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Part II

Environmental Protection Agency

40 CFR Part 98

**Mandatory Reporting of Greenhouse
Gases; Final Rule**

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 98****[EPA-HQ-OAR-2008-0508; FRL-9234-7]****RIN 2060-AQ33****Mandatory Reporting of Greenhouse Gases****AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Final rule.

SUMMARY: EPA is amending specific provisions in the greenhouse gas reporting rule to clarify certain provisions, to correct technical and editorial errors, and to address certain questions and issues that have arisen since promulgation. These final changes include generally providing additional information and clarity on existing requirements, allowing greater flexibility or simplified calculation methods for certain sources, amending data reporting requirements to provide additional clarity on when different types of greenhouse gas emissions need to be calculated and reported, clarifying terms and definitions in certain equations and other technical corrections and amendments.

DATES: The final rule is effective on December 31, 2010. The incorporation by reference of certain publications listed in the final rule amendments are approved by the director of the **Federal Register** as of December 31, 2010.

ADDRESSES: EPA has established a docket under Docket ID No. EPA-HQ-OAR-2008-0508 for this action. All documents in the docket are listed in the <http://www.regulations.gov> index. 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 Ave., NW., Washington, DC. 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) 566-1742.

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 Greenhouse Gas Reporting Program 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"). These are final amendments to existing regulations. These amended regulations affect owners or operators of certain suppliers and 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
General Stationary Fuel Combustion Sources.		Facilities operating boilers, process heaters, incinerators, turbines, and internal combustion engines.
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.
Electricity Generation	221112	Fossil-fuel fired electric generating units, including units owned by Federal and municipal governments and units located in Indian Country.
Adipic Acid Production	325199	Adipic acid manufacturing facilities.
Aluminum Production	331312	Primary aluminum production facilities.
Ammonia Manufacturing	325311	Anhydrous and aqueous ammonia production facilities.
Cement Production	327310	Portland Cement manufacturing plants.
Ferroalloy Production	331112	Ferroalloys manufacturing facilities.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
	325120	Chlorodifluoromethane manufacturing facilities.
HCFC-22 Production and HFC-23 Destruction.		
Hydrogen Production	325120	Hydrogen production facilities.
Iron and Steel Production	331111	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace shops.
Lead Production	331419	Primary lead smelting and refining facilities.
	331492	Secondary lead smelting and refining facilities.
Lime Production	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Nitric Acid Production	325311	Nitric acid production facilities.
Petrochemical Production	32511	Ethylene dichloride production facilities.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
Petroleum Refineries	325199	Acrylonitrile, ethylene oxide, methanol production facilities.
Phosphoric Acid Production	325110	Ethylene production facilities.
Pulp and Paper Manufacturing	325182	Carbon black production facilities.
	324110	Petroleum refineries.
	325312	Phosphoric acid manufacturing facilities.
	322110	Pulp mills.
	322121	Paper mills.
	322130	Paperboard mills.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing facilities.
Soda Ash Manufacturing	325181	Alkalies and chlorine manufacturing facilities.
	212391	Soda ash, natural, mining and/or beneficiation.
Titanium Dioxide Production	325188	Titanium dioxide manufacturing facilities.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust reclaiming facilities, recovering from scrap and/or alloying purchased metals.
Municipal Solid Waste Landfills	562212	Solid waste landfills.
Manure Management ^a	221320	Sewage treatment facilities.
	112111	Beef cattle feedlots.
	112120	Dairy cattle and milk production facilities.
	112210	Hog and pig farms.
	112310	Chicken egg production facilities.
	112330	Turkey Production.
	112320	Broilers and other meat type chicken production.
Suppliers of Natural Gas and NGLs	221210	Natural gas distribution facilities.
	211112	Natural gas liquid extraction facilities.
Suppliers of Industrial GHGs	325120	Industrial gas production facilities.
Suppliers of Carbon Dioxide (CO ₂)	325120	Industrial gas production facilities.

^aEPA will not be implementing subpart JJ of 40 CFR part 98 using funds provided in its FY2010 appropriations or Continuing Appropriations Act, 2011 (Pub. L. 111–242), due to a Congressional restriction prohibiting the expenditure of funds for this purpose.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities and suppliers likely to be affected by this action. Table 1 of this preamble lists the types of facilities and suppliers that EPA is now aware could be potentially affected by the reporting requirements. Other types of facilities and suppliers than those 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 or the relevant criteria in the subparts. If you have questions regarding the applicability of this action to a particular facility or supplier, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on December 31, 2010. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. EPA is issuing this final rule under section 307(d)(1) of the Clean Air Act, which states: “The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies.” Thus, section

553(d) of the APA does not apply to this rule. EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making this rule effective on December 31, 2010. Section 5 U.S.C. 553(d)(3) allows an effective date less than 30 days after publication “as otherwise provided by the agency for good cause found and published with the rule.” As explained below, EPA finds that there is good cause for this rule to become effective on December 31, 2010, even though this results in an effective date fewer than 30 days from date of publication in the **Federal Register**.

While this action is being signed prior to December 1, 2010, there is likely to be a significant delay in the publication of this rule as it contains complex equations and tables and is relatively long in length. As an example, EPA signed a shorter technical amendments package related to the same underlying reporting rule on October 7, 2010, and it was not published until October 28, 2010 (75 FR 66434), three weeks later.

The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Where, as here, the final rule will be signed and made available on the EPA Web site more than 30 days before the effective date, but where the publication is likely

to be delayed due to the complexity and length of the rule, that purpose is still met. Moreover, most of the revisions being made in this package provide flexibilities to sources covered by the reporting rule, or otherwise relieve a restriction. Thus, a shorter effective date in such circumstances is consistent with the purposes of APA section 553(d), which provides an exception for any action that grants or recognizes an exemption or relieves a restriction. Accordingly, we find good cause exists to make this rule effective on December 31, 2010, consistent with the purposes of 5 U.S.C. 553(d)(3).

Judicial Review. Under section 307(b)(1) of the CAA, 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 (the Court) by February 15, 2011. 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. CAA section 307(d)(7)(B) also provides a mechanism for EPA 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 the 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 20460, 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.

API American Petroleum Institute
 ARP Acid Rain Program
 ASME American Society of Mechanical Engineers
 ASTM American Society for Testing and Materials
 BAMM best available monitoring method
 CAA Clean Air Act
 cc cubic centimeters
 CE calibration error
 CEMS continuous emission monitoring system
 CFR Code of Federal Regulations
 CGA Cylinder gas audit
 CH₄ methane
 CO carbon monoxide
 CO₂ carbon dioxide
 CO₂e CO₂-equivalent
 CWPB center worked prebake
 FR Federal Register
 FTIR Fourier transform infrared
 GC gas chromatography
 GHG greenhouse gas
 GHGRP Greenhouse Gas Reporting Program
 GPA Gas Processors Association
 GWP global warming potential
 HFCs hydrofluorocarbons
 HHV high heat value
 HSS horizontal stud Söderberg
 IPCC Intergovernmental Panel on Climate Change
 IR infrared
 LDCs local natural gas distribution companies
 mmBtu/hr million British thermal units per hour
 mscf thousand standard cubic feet
 MSW municipal solid waste
 mtCO₂e metric tons of CO₂ equivalents
 MVC molar volume conversion factor
 NESHAP National Emission Standards for Hazardous Air Pollutants
 NIST National Institute of Standards and Technology
 NMR nuclear magnetic resonance
 NSPS New Source Performance Standards

N₂O nitrous oxide
 NAICS North American Industry Classification System
 NGLs natural gas liquids
 O₂ oxygen
 OMB Office of Management and Budget
 PFC perfluorocarbon
 psia pounds per square inch absolute
 QA quality assurance
 QA/QC quality assurance/quality control
 RATA relative accuracy test audit
 RFA Regulatory Flexibility Act
 scf standard cubic feet
 scfm standard cubic feet per minute
 SF₆ sulfur hexafluoride
 SO₂ sulfur dioxide
 SWPB side worked prebake
 U.S. United States
 VSS vertical stud Söderberg

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I. Background

A. How is this preamble organized?

The first section of this preamble contains the basic background information about the origin of these rule amendments. This section also discusses EPA's use of our legal authority under the CAA to collect data on GHGs.

The second section of this preamble describes in detail the rule changes that are being promulgated to, among other things, correct technical errors, provide clarification, and address implementation issues identified by EPA and others. This section also presents a summary and EPA's response to the major public comments submitted on the proposed rule amendments, and significant changes, if any, made since proposal in response to those comments.

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

B. Background on This Action

The final Mandatory Reporting of Greenhouse Gases Rule was signed by EPA Administrator Lisa Jackson on September 22, 2009 and published in the **Federal Register** on October 30, 2009 (74 FR 56260–56519). This rule, which added Part 98 to chapter 40 of the Code of Federal Regulations (CFR) as well as amending other parts of 40 CFR, became effective on December 29, 2009, and included reporting of GHG information from facilities and suppliers, consistent with the 2008 Consolidated Appropriations Act.¹ These source categories capture approximately 85 percent of U.S. GHG emissions through reporting by direct emitters as well as certain suppliers (e.g., fossil fuel, petroleum products, industrial gases and CO₂) and manufacturers of mobile sources.

EPA published a notice proposing these amendments to Part 98 to, among other things, correct certain technical and editorial errors that have been identified since promulgation and clarify or propose amendments to certain provisions that have been the subject of questions from reporting entities. The proposal was published on

¹ Consolidated Appropriations Act, 2008, Pub. L. 110–161, 121 Stat. 1844, 2128.

August 11, 2010 (75 FR 48744). The public comment period for the proposed rule amendments ended on September 27, 2010. EPA did not receive any requests to hold a public hearing.

This is the second time that EPA has published a notice promulgating amendments to Part 98 to, among other things, correct certain technical and editorial errors identified since Part 98 was originally promulgated and to clarify and amend certain provisions that have been the subject of questions from reporting entities. The first final rule amendments were published on October 28, 2010 (75 FR 66434). This final rule complements the final rule published on October 28, 2010 and is not intended to duplicate or replace those amendments.

C. Legal Authority

EPA is promulgating these rule amendments under its existing CAA authority, specifically authorities provided in CAA section 114.

As stated in the preamble to the 2009 final rule (74 FR 56260, October 30, 2009), CAA section 114 provides EPA broad authority to require the information mandated by Part 98 because such data would inform and are relevant to EPA's obligation to carry out a wide variety of CAA provisions. As discussed in the preamble to the initial proposal (74 FR 16448, April 10, 2009), CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, manufacturers of process or control equipment, and 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. For further information about EPA's legal authority, see the preambles to the proposed and final rule, and Response to Comments Documents.²

D. How will these amendments apply to 2011 reports?

We have determined that it is feasible for sources to implement these changes for the 2010 reporting year because the revisions primarily provide additional clarifications regarding the existing regulatory requirements, generally do not affect the type of information that must be collected and do not substantially affect how emissions are calculated. Our rationale for this determination is explained in the

preamble to the proposed rule amendments.³ In response to general comments submitted on the proposed rulemaking, we have again reviewed the final amendments and determined that, with one limited exception, they can be implemented, as finalized, for the 2010 reporting year.

The one new requirement, regarding reporting of biogenic CO₂ emissions from units subject to 40 CFR Part 75, is being phased in, so that it remains optional for reporting year 2010, but becomes mandatory for each subsequent year. Therefore this revision, as finalized, already accommodates implementation for the 2010 reporting year.

In summary, except for the exception discussed above regarding biogenic CO₂ emissions, these amendments do not require any additional monitoring or data collection above what was already included in Part 98. Therefore, we have determined that reporters can use the same information that they have been collecting under Part 98 for each subpart to calculate and report GHG emissions for 2010 and submit reports in 2011 under the amended subparts.

Following is a brief summary of major comments and responses. Several comments were received on this topic. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: Several commenters requested that we make use of the amendments optional for the 2010 reporting year and mandatory beginning with the 2011 reporting year. The commenters expressed concern that in 2010, sources may not have been collecting the required data to implement certain amendments.

Response: We sought comment on the feasibility of incorporating the proposed revisions for the 2010 reporting year. In the proposal, we explained that we felt implementation for the 2010 reporting year would be feasible because the proposed revisions, to a great extent, would simply clarify existing regulatory requirements or add flexibility to the rule. Further, the proposed amendments would not substantially affect the type of information that must be collected or how emissions are calculated. We sought comment on this conclusion and whether this timeline is feasible or appropriate, considering the nature of the proposed changes and the way in which data have been collected thus far

in 2010. We requested that commenters provide specific reasons why they believe that the proposed implementation schedule would or would not be feasible. We received some comments about making optional the use of the amendments in 2010, as well as comments proposing to extend submission of the first reports until June 1, 2011. We received a few industry-specific examples providing a rationale for extending the deadline for reporting, or making use of the amendments optional for the 2010 reporting year. For example, some commenters expressed concern that the proposed clarification of the definition of natural gas, as well as the introduction of fuel gas into Table C-1, could affect applicability under the rule and the use of the tiers under subpart C. We have addressed the underlying concerns expressed by these commenters, as EPA did not intend to change applicability or force facilities to use higher tiered calculation methodologies. Therefore, because we addressed the underlying concerns, we are finalizing requirements to incorporate the amendments into 2010 reporting year data.

II. Final Amendments and Responses to Public Comments

We are amending various subparts in Part 98 to correct errors in the regulatory language that were identified as a result of working with reporters to implement the various subparts of Part 98. We are also amending certain rule provisions to provide greater clarity. The amendments to Part 98 include the following types of changes:

- Additional information to understand better or more fully compliance obligations in a specific provision, such as the reference to a standardized method that must be followed.
- Amendments to certain equations to better reflect actual operating conditions.
- Corrections to terms and definitions in certain equations.
- Corrections to data reporting requirements so that they more closely conform to the information used to perform emission calculations.
- Amendments, in limited cases, to allow for the use of simplified emissions calculation methods.
- Changes to correct cross references within and between subparts.
- Other amendments related to certain issues identified as a result of working with reporters during rule implementation and outreach.
- Applying a threshold for reporting for local distribution companies of equal to or greater than 460,000 thousand

² 74 FR 16448 (April 10, 2009) and 74 FR 56260 (October 30, 2009). Response to Comments Documents can be found at <http://www.epa.gov/climatechange/emissions/responses.html>

³ 75 FR 48747 (August 11, 2010).

standard cubic feet (mscf) of natural gas delivered per year.

- Requiring separate reporting of biogenic CO₂ emissions for units that are also subject to 40 CFR part 75, beginning with the 2011 reporting year.

The final amendments promulgated by this action reflect EPA's consideration of the comments received on the proposal. The major public comments and EPA's responses for each subpart are provided in this preamble. Our responses to additional significant public comments on the proposal are presented in a comment response document available in Docket ID No. EPA-HQ-OAR-2008-0508.

A. Subpart A—General Provisions: Best Available Monitoring Methods

1. Summary of Final Amendments and Major Changes Since Proposal

EPA is finalizing the petition process established in 40 CFR 98.3(j) that allows use of Best Available Monitoring Methods (BAMM) past December 31, 2010 for owners and operators required to report under subpart P (Hydrogen Production), subpart X (Petrochemical Production), or subpart Y (Petroleum Refineries), under limited circumstances. Owners or operators subject to these subparts can petition EPA to extend use of BAMM past December 31, 2010, if compliance with a specific provision in the regulation requires measurement device installation, and installation would necessitate an unscheduled process equipment or unit shutdown, or could be installed only through a "hot tap." If the application is approved, the owner or operator can postpone installation of the measurement device until the next scheduled maintenance outage, but initially no later than December 31, 2013. If, in 2013, owners or operators still determine and certify that a scheduled shutdown will not occur by December 31, 2013, they may re-apply to use best available monitoring methods for an additional two years.

Process for requesting an extension of best available monitoring methods. We are adding a similar petition process to that recently concluded for the use of BAMM for 2010 in 40 CFR 98.3(j). The process is for quantifying emissions from any source category at facilities subject to subparts P, X and/or Y, and solely for the installation of measurement devices that cannot be installed safely except during full process equipment or unit shutdown or through installation via a hot tap. BAMM is allowable initially no later than December 31, 2013. Subpart P, X, and/or Y owners or operators requesting

to use BAMM beyond 2010 are required to electronically notify EPA by January 1, 2011 that they intend to apply for BAMM for installation of measurement devices and certify that such installation will require a hot tap or unscheduled shutdown.

Owners or operators must submit the full extension request for BAMM by February 15, 2011. The full extension request must include a description of the measurement devices that could not be installed in 2010 without a process equipment or unit shutdown, or through a hot tap, a clear explanation of why that activity could not be accomplished in 2010 with supporting material, an estimated date for the next planned maintenance outage, and a discussion of how emissions will be calculated in the interim. More specifically, the full extension request must identify the specific monitoring instrumentation for which the request is being made, indicate the locations where each piece of monitoring instrumentation will be installed, and note the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed. The extension requests must also include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process equipment or unit shutdown, or through a hot tap, as well as providing the dates of the three most recent process equipment or unit shutdowns, the typical frequency of shutdowns for the respective equipment or unit, and the date of the next planned shutdown.

Once subpart P, X, and/or Y owners or operators have notified EPA of their plan to apply for BAMM for measurement device installation, by January 1, 2011, and subsequently submitted a full extension request, by February 15, 2011, they can automatically use BAMM consistent with their request through June 30, 2011. This automatic extension is necessary because the current BAMM requests submitted by these facilities will end no later than December 31, 2010. The BAMM must be extended automatically to provide EPA the time to review thoroughly the BAMM requests submitted for post-2010, while ensuring that the petitioning facilities are not out of compliance with the rule during that review process. All measurement devices must be installed by July 1, 2011 unless EPA approves the BAMM extension request before that date.

Approval of extension requests. In any approval of an extension request, EPA will approve the extension itself,

establish a date by which all measurement devices must be installed, and indicate the approved alternate method for calculating GHG emissions in the interim.

If EPA approves an extension request, the owner/operator has until the date approved by EPA to install the relevant remaining meters or other measurement devices, however initial approvals will not grant extensions beyond December 31, 2013. An owner/operator that already received approval from EPA to use BAMM during part or all of 2010 is required to submit a new request for use of BAMM beyond 2010. Unless EPA has approved an extension request, all owners or operators that submit a timely request under this new process for BAMM will be required to install all measurement devices by July 1, 2011.

We recognize that occasionally a facility may plan a scheduled process equipment or unit shutdown and the installation of required monitoring equipment, but the date of the scheduled shutdown is changed. We are adding a process by which owners or operators who receive an extension will have the opportunity to extend the use of BAMM beyond the date approved by EPA if they can demonstrate to the Administrator's satisfaction that they are making a good faith effort to install the required equipment. At a minimum, facilities that determine that the date of a scheduled shutdown will be postponed are required to notify EPA within 4 weeks of such a determination, but no later than 4 weeks before the date for which the planned shutdown was scheduled.

One-time request to extend best available monitoring methods past December 31, 2013. If subpart P, X, and/or Y owners or operators determine that a scheduled shutdown will not occur by December 31, 2013 and thus they want to continue to use BAMM, they are required to re-apply to use BAMM for one additional time period, not to extend beyond December 31, 2015. To obtain an extension for the use of BAMM past December 31, 2013, owners or operators are required to submit a new extension request by June 1, 2013 that contains the information required in 40 CFR 98.3(j)(4). All owners or operators that submit a request under this paragraph to extend the use of best available monitoring methods for measurement device installation are required to install all measurement devices by December 31, 2013, unless the additional extension request under this paragraph is approved by EPA.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this topic. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: EPA received several comments, both in support of and in opposition to, the proposed extension of BMM for facilities subject to subparts P, X and Y. Some commenters that supported the new BMM process also recommended that EPA extend the process beyond hydrogen producers, petrochemical facilities and petroleum refineries. They suggested that the same logic should apply to all facilities, that installation of monitoring equipment should not require process equipment or unit shutdown.

Other commenters were concerned that the new BMM process conflicts with the need for consistent data. The commenters urged that if EPA nevertheless decides to finalize the requirements, there should be only a one-time application process with BMM ending no later than December 2013. Further, they asserted that EPA should require facilities to make use of unplanned shutdowns as an opportunity to install equipment.

Response: EPA carefully considered the issues raised by commenters and decided to retain the BMM extension process, as proposed, only for facilities subject to subparts P, X and Y. The proposal preamble sought comment on this very issue and requested that commenters provide information on additional subparts, if any, that would need this flexibility, and include information on why installation could not be done in the absence of such a shutdown or why such shutdowns did not or could not occur in 2010 without unreasonable burden on the facility. Commenters did not provide the requested information to support their position that the provision should be extended to other industries. In summary, the commenters argued only that EPA should provide this flexibility, but did not provide a rationale as to why additional industries needed the flexibility.

Regarding concerns that the new BMM process would lead to inconsistent data, EPA has determined that this limited opportunity for a BMM extension will provide sufficiently consistent data for these

industries without causing the unnecessary burden or potential safety concerns that would be associated with installation of monitoring devices during unplanned shutdowns or hot taps. EPA notes that the BMM process will still require facilities to follow the calculation methods in the rule, but will allow owners or operators to use alternative methods to provide the inputs to those calculations. Further, unlike the BMM process that was established by promulgation of the October 30, 2009 reporting rule (74 FR 56379-56380), any request for BMM after 2010 will require EPA approval of a facility's proposed approach to be implemented in lieu of the requirements in the rule. This further ensures that EPA will continue to receive data of the appropriate quality.

EPA decided not to limit BMM to a one-time extension through 2013, because we determined that the reasons supporting extension through 2013 were still valid post 2013. Specifically, facilities in these particularly complex industries should not have to shut down unnecessarily in order to install equipment. Data provided by these industries show that some units, for example crude distillation units, are shut down only every 4 to 7 years. Other units such as vacuum distillation units, fluid catalytic cracking units, distillate hydrotreating units, catalytic feed hydrotreaters, hydrocrackers, coking units, sulfur recovery units and cogeneration units can be shut down as infrequently as every 5 years (see final Background Technical Support document to the Revision of Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule). Thus, providing a potential end date for BMM of December 31, 2015, is appropriate based on information presented for these industries on the typical frequency of shutdown for these facilities.

We also are not requiring a facility to order the measurement equipment early and have it on hand in the event of an unplanned shutdown before the scheduled shutdown. First, it would be hard to enforce a requirement to install equipment during an unplanned shutdown "if feasible" because it would be hard to objectively determine whether a facility should have installed equipment during an unplanned shutdown. Moreover, during an unplanned shutdown, the priority is often to get the equipment up and running as quickly and safely as possible; therefore, there is not necessarily time to install the measurement equipment.

Comment: In a related comment, one commenter raised concerns about Tier 3 monitoring requirements for a stream at its facility that is dangerous to monitor due to the presence of hydrogen cyanide. They indicated that they used BMM to implement an approach other than direct sampling of the inputs to the equations for the 2010 reporting year, and now are considering implementing the Tier 4 method for future years. However, they argued the rule should provide a mechanism to address these dangerous streams.

Response: No rule change has been made as a result of the comment. For the 2010 reporting year, the BMM provisions were designed for use where it was not possible to acquire, install and operate a required piece of equipment during the early months of the GHG Reporting Program. Safety concerns were a valid reason for approving these early BMM applications.

Although the commenter notes concerns with conducting the Tier 3 method for quantifying emissions from stationary combustion at the facility due to the presence of a hydrogen cyanide stream, EPA notes that the rule does not limit them to use of a Tier 3 approach. As acknowledged by the commenter, they also have the opportunity to use Tier 4 to meet the requirements of the rule and, by taking advantage of BMM for 2010, had one year to install the Tier 4 equipment. The commenter merely wants additional time beyond that already provided in the rule to comply with the Tier 4 requirements. The commenter does not justify the requested extension by pointing to issues like unplanned shutdowns or hot taps, as discussed in the proposal. EPA has determined the unique situation raised by the commenter does not warrant expanding the BMM process generally beyond industries subject to subparts P, X and Y.

B. Subpart A—General Provisions: Calibration Requirements

1. Summary of Final Amendments and Major Changes Since Proposal

EPA has finalized amendments to 40 CFR 98.3(i)(1) to specify that the calibration accuracy requirements of 40 CFR 98.3(i)(2) and (i)(3) are required only for flow meters that measure liquid and gaseous fuel feed rates, feedstock flow rates, or process stream flow rates that are used in the GHG emissions calculations, and only when the calibration accuracy requirement is specified in an applicable subpart of Part 98. For instance, the QA/QC requirements in 40 CFR 98.34(b)(1) of

subpart C require all flow meters that measure liquid and gaseous fuel flow rates for the Tier 3 CO₂ calculation methodology to be calibrated according to 40 CFR 98.3(i); therefore, the accuracy standards in 40 CFR 98.3(i)(2) and (i)(3) will continue to apply to these meters.

We are also amending 40 CFR 98.3(i) to clarify that the calibration accuracy specifications of 40 CFR 98.3(i)(2) and (i)(3) do not apply where the use of company records or the use of best available information is specified to quantify fuel usage or other parameters, nor do they apply to sources that use Part 75 methodologies to calculate CO₂ mass emissions because the Part 75 quality-assurance is sufficient. Although calibration accuracy requirements are not applicable for these data sources, per the requirements of 98.3(g)(5), reporters are still required to explain in their monitoring plan the processes and methods used to collect the necessary data for the GHG calculations.

We are also amending 40 CFR 98.3(i)(1) to clarify that the calibration accuracy specifications in 40 CFR 98.3(i)(2) and (i)(3) do not apply to other measurement devices (e.g., weighing devices) that provide data for the GHG emissions calculations. Rather, these devices must be calibrated to meet the accuracy requirements of the relevant subpart(s), or, in the absence of such requirements, meet appropriate, technology-based error-limits, such as industry consensus standards or manufacturer's accuracy specifications. Consistent with 40 CFR 98.3(g)(5)(i)(C), the procedures and methods used to quality-assure the data from the measurement devices must be documented in the written monitoring plan.

We are adding a new paragraph 40 CFR 98.3(i)(1)(ii) to clarify that flow meters and other measurement devices need to be installed and calibrated by the date on which data collection needs to begin, if a facility or supplier becomes subject to Part 98 after April 1, 2010.

We are adding new paragraph 40 CFR 98.3(i)(1)(iii) to specify the frequency at which subsequent recalibrations of flow meters and other measurement devices must be performed. Recalibration must be at the frequency specified in each applicable subpart, or at the frequency recommended by the manufacturer or by an industry consensus standard practice, if no recalibration frequency was specified in an applicable subpart.

We are adding new paragraph 40 CFR 98.3(i)(7) to specify the consequences of a failed flow meter calibration. Data become invalid prospectively, beginning

at the hour of the failed calibration and continuing until a successful calibration is completed. Appropriate substitute data values must be used during the period of data invalidation.

In 40 CFR 98.3(i)(2) and (3), we are adding absolute value signs to the numerators of Equations A-2 and A-3. These were inadvertently omitted in the October 30, 2009 Part 98.

We are also amending 40 CFR 98.3(i)(3) to increase the alternative accuracy specification for orifice, nozzle, and venturi flow meters (*i.e.*, the arithmetic sum of the three transmitter calibration errors (CE) at each calibration level) from 5.0 percent to 6.0 percent, since each transmitter is individually allowed an accuracy of 2.0 percent. We are also amending 40 CFR 98.3(i)(3) for orifice, nozzle, and venturi flow meters to account for cases where not all three transmitters for total pressure, differential pressure, and temperature are located in the vicinity of a flow meter's primary element. Instead of being required to install additional transmitters, reporters are, as described below, conditionally allowed to use assumed values for temperature and/or total pressure based on measurements of these parameters at remote locations. If only two of the three transmitters are installed and an assumed value is used for temperature or total pressure, the maximum allowable calibration error is 4.0 percent. If two assumed values are used and only the differential pressure transmitter is calibrated, the maximum allowable calibration error is 2.0 percent.

We are also amending 40 CFR 98.3(i)(3) to add five conditions that must be met in order for a source to use assumed values for temperature and/or total pressure at the flow meter location, based on measurements of these parameters at a remote location (or locations).

- The owner or operator must demonstrate that the remote readings, when corrected, are truly representative of the actual temperature and/or total pressure at the flow meter location, under all expected ambient conditions. Pressure and temperature surveys can be performed to determine the difference between the readings obtained with the remote transmitters and the actual conditions at the flow meter location.

- All temperature and/or total pressure measurements in the demonstration must be made with calibrated gauges, sensors, transmitters, or other appropriate measurement devices.

- The methods used for the demonstration, along with the data from the demonstration, supporting engineering calculations (if any), and the mathematical relationship(s) between the remote readings and the actual flow meter conditions derived from the demonstration data must be documented in the monitoring plan for the unit and maintained in a format suitable for auditing and inspection.

- The temperature and/or total pressure at the flow meter must be calculated on a daily basis from the remotely measured values, and the measured flow rates must then be corrected to standard conditions.

- The mathematical correlation(s) between the remote readings and actual flow meter conditions must be checked at least once a year, and any necessary adjustments must be made to the correlation(s) going forward.

We are amending 40 CFR 98.3(i)(4) to include an additional exemption from the calibration requirements of 40 CFR 98.3(i) for flow meters that are used exclusively to measure the flow rates of fuels used for unit startup. For instance, a meter that is used only to measure the flow rate of startup fuel (e.g., natural gas) to a coal-fired unit is exempted.

Section 98.3(i)(4) is being further amended to clarify that gas billing meters are exempted from the monitoring plan and recordkeeping provisions of 40 CFR 98.3(g)(5)(i)(c), (g)(6) and (g)(7), which require, respectively, that a description of the methods used to quality-assure data from instruments used to provide data for the GHG emissions calculations be included in the written monitoring plan, that the results of all required certification and QA tests be kept, and that maintenance records be kept for those instruments.

We are amending 40 CFR 98.3(i)(5) to clarify that flow meters that were already calibrated according to 40 CFR 98.3(i)(1) following a manufacturer's recommended calibration schedule or an industry consensus calibration schedule do not need to be recalibrated by the date specified in 40 CFR 98.3(i)(1) as long as the flow meter is still within the recommended calibration interval. This paragraph is also being amended to clarify that the deadline for successive calibrations will be according to the manufacturer's recommended calibration schedule or an industry consensus calibration schedule.

We are amending 40 CFR 98.3(i)(6) to account for units and processes that operate continuously with infrequent outages and cannot meet the flow meter calibration deadline without disrupting

normal process operation. Part 98 allowed the owner or operator to postpone the initial calibration until the next scheduled maintenance outage. Although the rule allowed postponement of calibration, it did not specify how to report fuel consumption for the entire time period extending from January 1, 2010 until the next maintenance outage. We are amending 40 CFR 98.3(i)(6) to permit sources to use the best available data from company records to quantify fuel usage until the next scheduled maintenance outage. This revision addresses situations where the next scheduled outage is in 2011, or later.

The major change since proposal is identified in the following list. The rationale for this and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

- Removed the words "ignition" and "ignition fuel" from 40 CFR 98.3(i)(4), so that only fuel flow meters that are used exclusively for startup are exempted from the calibration requirements of 40 CFR 98.3(i).

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this topic. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: We received several comments relating to the proposed changes to the calibration accuracy requirements set in 40 CFR 98.3(i). Commenters expressed concern that removing the rule-wide 5 percent calibration accuracy requirement would compromise the rule's data quality. The commenters noted that a global calibration accuracy requirement is necessary to provide data that are accurate and comparable within and across industries. By dropping this requirement, the commenters believed small calibration errors will systematically produce major errors in reported data. For measuring devices other than flow meters they argued that it is not clear what an "appropriate" error range is, or what calibration standards a reporter would deem "applicable," and suggest that by stating calibration standards are "not limited to industry standards * * *," EPA is

waiving calibration requirements for other measuring devices altogether. They acknowledge that there is a requirement to document the calibration procedure used in the monitoring plan, but they believe it is not enforceable and severely reduces transparency. The commenters contend that the use of different calibration methods and varying levels of accuracy would make it difficult to correctly interpret and compare the emissions data, and would render future policy development very difficult.

In summary, commenters that were concerned about our removal of the blanket 5 percent calibration accuracy requirements asserted that EPA has a mandate to implement the rule and cannot promulgate any subsequent rule that would compromise the quality of the data reported. They further argue that it is arbitrary and capricious, in light of EPA's reporting mandate, to waive the calibration accuracy requirements for any flow meters. All such meters, they contend, should be required to meet these minimum accuracy requirements, with no exceptions.

Response: We acknowledge the concerns of the commenters and agree that a high level of data quality is a valuable component of any environmental program. However, we believe the changes to the calibration accuracy requirements of 40 CFR 98.3(i) do not jeopardize the integrity of the reporting program nor compromise EPA's ability to use the data in the future to support climate policy development.

As originally promulgated, 40 CFR 98.3(i) required that "all measurement devices shall be calibrated to an accuracy of 5 percent." However, as promulgated, 40 CFR 98.3(i)(2) and (i)(3) only provided calibration procedures for flow meters. No specific procedures were provided for other measurement devices. As a result, measurement devices other than flow meters would necessarily be calibrated according to procedures specified in other subparts, industry consensus methods, or manufacturer specifications.

In the "Technical Support Document for Revision of Certain Provisions: Proposed Rule for Mandatory Reporting of Greenhouse Gases," dated July 8, 2010 (the TSD), vendor information on various types of measuring devices shows accuracy ranges of significantly less than 5 percent. Requiring the calibrations to be performed according to the accuracy specified by the device manufacturer, rather than 5 percent, would likely actually increase the data accuracy of the rule. In addition, we

recognize that other programs to which reporters may be subject impose calibration standards that will affect many of the instruments used for reporting under Part 98. For example, the tested accuracy of fuel flow meters and transmitter transducers used in the Acid Rain Program from 2005 through 2009 was well below 1 percent.

As a result of the wide range of industries and measuring devices used within each industry, we have determined it is not practical to set a global calibration standard or method that would apply generically to every measurement device. Replacing the 5 percent requirement from the 2009 fine rule with manufacturer's specifications or industry specific standards will provide a higher level of data certainty across the rule while accommodating the wide variety of industries and equipment covered by the rule. We think it is highly unlikely that companies will choose to use arbitrary standards, as the procedures and methods used to quality-assure the measurement data must be listed in the facility or supplier's monitoring plan.

The commenters correctly note that the calibration accuracy requirements of 40 CFR 98.3(i) have been removed where company records or best available information are used. Since promulgation, we have consistently affirmed that meters used to generate company records are not required to be calibrated according to 40 CFR 98.3(i). The purpose behind allowing the use of company records and best available information was to permit companies to use fuel billing receipts or other quality assured information they currently maintain. EPA authorized the use of company records to alleviate burden and did not intend for such data to be subject to additional calibration requirements, which would defeat the purpose of this flexibility.

To be clear, we disagree with the commenter's assertions that we are "waiving" any calibration accuracy requirements or that certain types of flow meters would not have to be calibrated. All measurement technologies, except for the limited exceptions in 40 CFR 98.3(i) must meet calibration accuracy requirements. Further, most major emission sources should be covered by either the requirements of 40 CFR 98.3(i) or another program that provides a similarly, if not significantly more, stringent accuracy requirement. We have concluded that the amendments to the calibration accuracy requirements do not compromise our ability to implement successfully this reporting rule.

Comment: One commenter pointed out an inconsistency in the proposed rule regarding the term “ignition fuel.” EPA proposed to amend 40 CFR 98.3(i)(4) to exempt fuel flow meters that are used exclusively for startup and ignition fuel from the calibration requirements of 40 CFR 98.3(i). However, EPA also proposed in 40 CFR 98.30(d) to exempt pilot lights from GHG emission reporting requirements. The commenter noted that pilot lights are essentially the same as ignitors, and the reference in 40 CFR 98.3(i)(4) to flow meters that measure ignition fuel appears to imply that GHG emissions from the combustion of ignition fuel must be reported.

Response: The GHG emissions reporting exemption for pilot lights in 40 CFR 98.30(d) refers to emissions from combustion of the fuel that supplies the pilot light. Therefore, in the final rule, we have removed the words “ignition” and “ignition fuel” from 40 CFR 98.3(i)(4). Paragraph (i)(4) now refers only to startup fuel, which is distinctly different from ignition fuel. For instance, at startup, a coal-fired boiler may burn natural gas for several hours at high heat input values, whereas a pilot light is a small flame that simply ignites or initiates combustion of the main fuel (e.g., fuel oil).

C. Subpart A—General Provisions: Reporting of Biogenic Emissions

1. Summary of Final Amendments and Major Changes Since Proposal

Under the proposed amendments, EPA’s goal was to reflect in regulatory language clarifications that have been issued stating that separate reporting of biogenic emissions for units subject to 40 CFR part 75 was optional. To clarify this optional reporting, we proposed to amend the data elements in subpart A (specifically 40 CFR 98.3(c)(4)) and subpart C that currently require separate accounting and reporting of biogenic CO₂ emissions so that it is optional for units that are subject to subpart D of this part or units that use the methods in part 75 to quantify CO₂ mass emissions in accordance with 40 CFR 98.33(a)(5) (40 CFR part 75 units or “part 75 units”). More specifically, to effect this clarification, we proposed to revise the reporting for all facilities such that all facilities would report combined non-biogenic and biogenic CO₂, and all facilities, except those with “part 75 units,” would still have been required to calculate and report biogenic CO₂ emissions separately.

We received numerous adverse comments on the proposed amendments that would re-structure 40 CFR

98.3(c)(4) and clarify that separate reporting of biogenic CO₂ emissions was optional for “part 75 units”. Most commenters urged EPA to make separate reporting of biogenic emissions mandatory for all reporters. Many commenters also objected to the restructuring of 40 CFR 98.3(c)(4), which would have had all units reporting combined biogenic and non-biogenic CO₂ emissions.

Based on the comments received, we have decided to withdraw the proposed re-structuring of 40 CFR 98.3(c)(4). We have also reconsidered the optional reporting of biogenic CO₂ emissions reporting for “part 75 units”. In the final rule, a new paragraph, (c)(12), has been added to 40 CFR 98.3(c), which states that reporting biogenic CO₂ is optional for “part 75 units” only for the first year of the program (i.e., for the 2010 reporting year). Thereafter, all “part 75 units” must separately report their biogenic CO₂ emissions. We are allowing the optional biogenic CO₂ emissions reporting for the 2010 reporting year in light of the 2009 final rule, as well as our previous statements and guidance on the issue. It is likely that at least some 40 CFR part 75 sources are following that policy guidance and have elected not to separately report biogenic CO₂ emissions. It is equally likely that these sources have not been keeping the necessary records or performing the required emission testing to enable them to report these emissions for 2010.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA–HQ–OAR–2008–0508).

- Retaining the facility level reporting requirements from the 2009 final rule (74 FR 56373) in 40 CFR 98.3(c)(4) that requires reporting of CO₂ emissions (excluding biogenic CO₂) and separate reporting of biogenic emissions.

- Introducing new paragraph 40 CFR 98.3(c)(12) that allows facilities with 40 CFR part 75 units the option to include biogenic emissions in their facility totals for the 2010 reporting year only.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this topic. Responses to additional significant comments received can be found in the document, “Response to Comments: Revision to Certain

Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA–HQ–OAR–2008–0508).

Comment: EPA received a large number of comments related to the proposed amendments to make separate reporting of biogenic CO₂ emissions optional for units subject to 40 CFR part 75. The three main concerns, each raised by multiple commenters, were that (1) all reporters should be required to separately report biogenic CO₂ emissions; (2) reporters should never be required to combine fossil CO₂ and biogenic CO₂; and, (3) if EPA nevertheless finalizes requirements allowing separate reporting of biogenic CO₂ to be optional for units subject to 40 CFR part 75, then EPA’s implementation of the proposed revisions should be narrower in scope and not affect reporting requirements for all reporters.

Regarding the first issue, some commenters argued that the requirements of the Acid Rain Program (ARP) should not constrain EPA in the GHG context and that all reporters under 40 CFR part 98 should be required to report biogenic CO₂ emissions, regardless of the fact that such separate reporting is not a requirement in ARP. Commenters suggested that this is important for consistency across the GHG Reporting Program.

Several commenters suggested that it is never appropriate to combine fossil CO₂ and biogenic CO₂ into a single reported value. Commenters noted that there is a distinction between fossil CO₂ and biogenic CO₂ and that in order to ensure transparency for future climate policy these two values should not be combined into a single reported emissions value. Further, they argued that EPA’s proposed requirement for sources to combine fossil and biogenic emissions together in one total ignores the natural biomass carbon cycle and is counter to the principle of “carbon neutrality,” thereby overstating net CO₂ entering the atmosphere.

The commenters suggested that requiring separate reporting of biogenic CO₂ is consistent with the Intergovernmental Panel on Climate Change and national, regional, and corporate GHG protocols and that EPA should not depart from this established accounting convention. These commenters also pointed out that EPA uses this same rationale for requiring separate reporting of biogenic CO₂ emissions in its own response to comments to the GHG Reporting Rule (74 FR 56351). Further, the commenters articulated that separate reporting of biogenic emissions is necessary to

provide the public and policymakers with information on the extent of biomass combustion and the sectors of the economy where biomass fuels are used, which is information important for developing future climate policy. Several organizations also commented that an accurate, economy-wide inventory of biogenic CO₂ emissions is important because the evidence to date demonstrates that biomass is not inherently carbon neutral.

Finally, commenters noted that if EPA nevertheless decides to finalize the rule allowing optional reporting of biogenic CO₂ emissions for 40 CFR part 75 units, EPA should modify the proposed rule so the amendments affect only facilities with part 75 units, and do not change the reporting requirements for all other reporters. Commenters were concerned that EPA's proposed change required all reporters to report total CO₂ (including biogenic CO₂ emissions), but only required facilities with non-part 75 units to report their biogenic emissions separately. Facilities with part 75 units would have the option to report separately biogenic CO₂ from those units. The commenters suggested that if EPA chooses to finalize optional separate reporting for part 75 units, then EPA should revert to the reporting requirements in subpart A that were in the 2009 final rule (*i.e.*, report CO₂ excluding biogenic CO₂) (74 FR 56379) for all other reporters and add a new paragraph specifically for facilities with part 75 units.

Response: We appreciate the significant feedback generated by the proposed amendments designed to clarify that separate reporting of biogenic emissions was optional for units subject to 40 CFR part 75. We also recognize that many industry and environmental groups have significant interest in the treatment of biomass in GHG reports, and specifically in the accounting of biogenic CO₂ emissions. Based on the significant feedback received, including comments received from facilities with 40 CFR part 75 units, as well as the fact that one of the fundamental goals of the Greenhouse Gas Reporting Program (GHGRP) is to collect data to support a range of potential future climate policies, we have reconsidered our position and decided to make the separate reporting of biogenic emissions mandatory for part 75 units beginning in the 2011 reporting year. Separate reporting of biogenic CO₂ emissions is optional for these units in the 2010 reporting year.

Per the requirements in the new paragraph 40 CFR 98.3(c)(12), facilities with one or more part 75 units must elect in the 2010 reporting year whether

to report biogenic CO₂ emissions from 40 CFR part 75 units separately, or report only total CO₂ emissions (including biogenic CO₂) for the 40 CFR part 75 units at their facility. Beginning in the 2011 reporting year, these facilities must separately report biogenic CO₂ emissions for the entire facility per the requirements in 40 CFR 98.3(c)(4), like all other facilities.

In addition, the final rule does not adopt the proposed restructuring of 40 CFR 98.3(c)(4) and leaves in place the facility-level reporting requirements in 40 CFR 98.3(c)(4) for any facility in 2010 or for future years. All other facilities, except those with part 75 units, must, as finalized in the 2009 final rule, report CO₂ (excluding biogenic CO₂) and then report separately biogenic CO₂ emissions. We would note that neither the original proposed amendments, nor the amendments finalized today, affect the fact that biogenic CO₂ emissions are excluded from the applicability determination under 40 CFR 98.2.

Commenters provided many reasons for supporting mandatory separate reporting of biogenic CO₂ emissions from all facilities, including the increased transparency that such reporting brings. Some commenters supported the assumption of the carbon neutrality of biomass while others dispelled it, but both sides were united in their comments that it is important to understand the GHG emissions associated with biomass consumption. Our decision to also require separate reporting of biogenic emissions for units that use the methods in 40 CFR part 75 is founded solely on the principle that having data available at a more disaggregated level for a reporting program like this one improves transparency and better enables us and other stakeholders to use the data to evaluate future potential policy options, without prejudging what those policies might be. This decision is not based on any conclusions about "carbon neutrality" or the appropriateness of combining fossil CO₂ and biogenic CO₂ into a single value.⁴ Rather, EPA's approach preserves the flexibility for the Agency and for stakeholders to understand reported CO₂ emissions in multiple ways. Despite the benefits of having separate data with which to distinguish biogenic CO₂ emissions, which we do not dispute, the 2009 final

⁴ EPA requested comment on approaches to accounting for GHG emissions from bioenergy and other biogenic sources earlier this year. The Call for Information (75 FR 41173 and 75 FR 45112), supporting information and comments can be found in docket EPA-HQ-OAR-2010-0560. Please refer to those documents for more information about this issue.

rule did not require this reporting for units subject to 40 CFR part 75. This is consistent with the Response to Comments document for subpart D of the final rule⁵ where it states "It is EPA's intent that Acid Rain Program units will be able to continue to measure and report CO₂ emissions as they do under the Acid Rain Program" which did not require separate reporting of biogenic CO₂. However, when we opened the relevant paragraphs to notice and comment, we received overwhelming support for making the separate reporting of biogenic CO₂ emissions mandatory, including from facilities with part 75 units. This support, in combination with the value of having the data for policy analysis, led us to reconsider our position and require separate reporting of biogenic CO₂ emissions beginning in the 2011 reporting year for the 40 CFR part 75 units. We decided to retain optional reporting for the 2010 reporting year due to the fact that we have provided guidance indicating that separate reporting was optional for these part 75 units, and therefore, some facilities may not have incorporated procedures into their monitoring plans or developed internal systems for collecting the necessary information to facilitate the biogenic CO₂ emissions calculations.

To implement the changes described above, we are adding new paragraph 40 CFR 98.3(c)(12), as well as amending paragraphs 40 CFR 98.33(e) (to provide an additional option for part 75 units to calculate the biogenic CO₂ emissions), 40 CFR 98.34(f), several paragraphs in 40 CFR 98.36(d), and 40 CFR 98.43.

D. Subpart A—General Provisions: Requirements for Correction and Resubmission of Annual Reports

1. Summary of Final Amendments and Major Changes Since Proposal

Subpart A, as promulgated in October 2009, required that an "owner or operator shall submit a revised report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors. * * *" We are amending 40 CFR 98.3(h) to clarify the types of errors that trigger a resubmission and the process for resubmitting annual GHG reports.

First, reports only have to be resubmitted when the owner or operator or the Administrator determines that a

⁵ Mandatory Greenhouse Gas Reporting Rule, EPA's Response to Public Comments, Volume 16, Subpart D Electricity Generation. Found at <http://www.epa.gov/climatechange/emissions/downloads09/documents/SubpartD-CommentResponses.pdf>.

substantive error exists. A substantive error is defined as one that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified. This clarification is important because some errors are not significant (e.g., an error in the zip code) and do not impact emissions. Such non-significant errors will not obligate the owner or operator to resubmit the annual report.

The owner or operator is required to resubmit the report within 45 days of identifying the substantive error, or of being notified by the Administrator of a substantive error, unless the owner or operator provides information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. This amendment provides owners and operators the opportunity to demonstrate whether an error the Administrator has deemed to be a substantive error is not, in fact, a substantive error.

Finally, we are also allowing owners and operators to request an extension of the 45-day resubmission deadline to address facility-specific circumstances that arise in either correcting an error or determining whether or not an identified error is, in fact, a substantive error. Owners and operators are required to notify EPA by e-mail at least two business days prior to the end of the 45-day resubmission deadline if they seek an extension. An automatic 30-day extension will be granted if EPA does not respond to the extension request by the end of the 45-day period.

We are including the opportunity to extend the period for resubmission in recognition that the data system is still under development and we do not yet fully know the full range of errors that will be identified and, therefore, the time required to address such errors. Verification and quality assurance and quality control checks are currently under development in the data system. Some flags that the data system might generate will not necessarily reflect substantive errors, but rather will be flags to alert the owner or operator to review the submission carefully to make sure the information provided is correct. On the other hand, some flags could identify substantive errors that affect the overall GHG emissions reported to EPA. Although we have concluded that it is important to provide facilities and suppliers the opportunity to extend this deadline, we believe that the 45-day time period is a sufficient time period for the vast majority of facilities and suppliers.

There have been no major changes from proposal regarding requirements for correction and resubmission of annual reports.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: One commenter, representing several organizations, was concerned that the amended process for submitting revised annual GHG reports upon identification or notification by EPA of an error was too complex and would substantially slow down correction of reported errors. Generally, they asserted that the 45-day process that was in the final Part 98 (74 FR 56381) should be appropriate for most reporters, and to the extent there were any outliers, then EPA could use enforcement discretion for those specific reporters as opposed to changing the rule for all reporters. The commenter was further concerned that EPA proposed to allow reporters to extend their resubmission deadline in the event of a disagreement between EPA and the reporter, by at least 30 days. The commenters suggested that the process does not give EPA a clear method to dispute these points with operators, does not specify that EPA's view trumps the operator's opinion, and does not allow members of the public to argue that an error is, in fact, substantive, and must be corrected. They contended that the overall process could take months or years to correct errors, and the operators may still refuse to correct some of them. They argued this is a departure from the existing rule, and serves only to hinder what was a straightforward and effective process.

Response: The process in these final rule amendments for submission of revised annual GHG reports to correct any substantive errors in these reports is reasonable and consistent with the purpose of the GHG Reporting Program. The purpose of these reporting requirements is to provide EPA with accurate and timely information on greenhouse gases in order to gain a better understanding of the relative emissions of specific industries and facilities, the factors that influence emission rates, and the actions that facilities could in the future, or already take, to reduce emissions. In light of this

purpose, it is reasonable to focus an ongoing requirement to correct errors in an annual report on "substantive errors," i.e., errors that affect emissions data quality, validation, or verification. Further, because this is a new program covering a wide variety of industries and processes, some of whom may not be familiar with GHG accounting and reporting, we have determined that under these circumstances it is reasonable to establish a procedure engaging owners and operators on whether the annual report actually contains identified "substantive errors."

The commenters' claims that this procedure provides no "clear method" of determining what are substantive errors, may take "months, perhaps years," may result in owners refusing to correct errors, and is unnecessary are unsupported and speculative. First, EPA has concluded that the definition of "substantive error"—an error that impacts emissions data quality or otherwise prevents the data from being validated or verified—is reasonably clear and is consistent with the purposes of GHG emissions reporting. The commenter fails to show what is unclear about this definition, nor why it is unreasonable to focus corrections on substantive errors, versus insignificant ones that do not impact the accuracy of submitted information.

Second, these final rule amendments set time limits for correction of substantive errors, i.e., correction through submission of a revised annual GHG report within 45 days of discovery (or notification by EPA of the errors) plus any "reasonable extensions" of time (including one automatic 30 day extension). The commenter fails to provide any basis for conflating these limited time frames into periods of many months or years. Further, because refusal by an owner or operator to correct substantive errors within the appropriate time frame would be a violation of the CAA and subject to significant civil penalties, the commenter has no basis for assuming that owners and operators would simply refuse to make the corrections.

Third, the error correction process provides a standard process that is applicable to all owners and operators and that owners and operators and EPA can use to attempt to resolve issues concerning error correction. EPA has determined that this process will likely result in more efficient error correction and resolution of error correction issues by setting a limited time for contesting EPA's identification of substantive errors. In addition, EPA's provision of a standard process provides more certainty for owners and operators of an

opportunity to resolve issues than if EPA were simply to rely on enforcement discretion, as recommended by a commenter.

The commenters also claimed the public will have no opportunity to argue that errors are substantive and should be corrected. However, this does not represent a change from the error correction process under the 2009 final rule. The amendments for resubmission of annual reports did not change public involvement in the resubmission process.

The process in today's rule better focuses the resources of EPA, regulated industries and the public on those errors that are most relevant to generating accurate data.

Comment: Several commenters requested that EPA provide a numerical determination of what is a "substantive error." One commenter proposed a +/– 10 percent change in the reported GHG emissions value as a result of the identified error. Another commenter requested that EPA clarify that substantive errors are only those that exceed 1 percent to 5 percent of the total annual CO₂ equivalent emissions.

One commenter requested that, in the final preamble, EPA clarify that any error not be considered substantive unless it exceeds 1 percent to 5 percent of the total annual CO₂ equivalent ("CO₂e") emission amount reported by an individual reporting facility. The commenter also requested that EPA modify the "contains one or more substantive errors" language to allow the agency flexibility to investigate potential as well as documented errors.

Response: The final rule defines substantive error as an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified. EPA has determined that it is not appropriate to establish a threshold below which errors do not have to be corrected and resubmitted. EPA has determined that if an error in the GHG emissions estimate occurs, then that emissions error should be corrected and the annual GHG emissions report resubmitted. If a facility were to go through the process of identifying the estimate in GHG emissions, calculating what the GHG emissions total should have been, and then determining the percent difference between the original reported estimate and the revised estimate, then the reporter has all of the information necessary to report that revised estimate.

E. Subpart A—General Provisions: Information To Record for Missing Data Events

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending 40 CFR 98.3(g)(4) by removing requirements to maintain records on the duration of a missing data event and actions taken to minimize future occurrences, while retaining the requirement that records be kept of the cause of each missing data event and the corrective actions taken. We are also clarifying that the records retained pursuant to 40 CFR 75.57(h) may be used to meet the recordkeeping requirements under Part 98 for the same missing data events.

There have been no major changes from proposal regarding recordkeeping requirements for missing data events.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA–HQ–OAR–2008–0508).

Comment: Some commenters stated that although EPA has justified this proposal by noting that 40 CFR part 75 does not require separate accounting of "the duration of missing data events or * * * actions taken to minimize occurrence in the future," that alone is not sufficient justification for not including these requirements under the reporting program. The commenters asserted that part 75's requirements do not constrain EPA's obligations in the GHG context. The commenters wrote that reporting the duration of a missing data event cannot be considered overly burdensome because reporters that accurately use missing data procedures must know the duration of missing data events and so must be collecting this information regardless. Also, the commenters indicated that most facilities covered by the rule do not use CEMS, and thus, EPA should not change the "minimize occurrence" requirement for all reporters (CEMS users and non-CEMS users) because missing data events associated with the use of CEMS often have no clear measures to avoid similar occurrences in the future.

Response: With respect to removal of the requirement to record the duration of a missing data event, EPA determined that the requirement in 40 CFR 98.3(c)(8) to report the total number of

hours in the year that missing data are used for each data element provides sufficient information for purposes of the GHG Reporting Program. Although the "total number of hours" will not provide information on the duration of each missing data event, EPA will know the total fraction of the year for which missing data are used for a particular data element. We have determined that this information provides EPA sufficient information on the extent of use of the missing data provisions for any given reporter.

EPA also decided to remove recordkeeping requirements related to "actions taken to prevent or minimize occurrence in the future" after considering the value of the potential loss of data as compared to the burden of compliance with the rule as written. As described below, we determined that sufficient information is available regarding missing data without requiring this additional information.

First, reporters must report annual hours for each missing data element. Through this reported data, EPA can identify whether missing data is particularly prevalent for a given data element at a given facility. Second, records must be retained on the cause of the event and actions taken to restore malfunctioning equipment. If EPA elects to review these records, this information, along with reported information on the total hours of missing data for each data element, will suggest whether the source is taking action to prevent or minimize occurrence in the future. Therefore, we have determined that it is not necessary to collect information specifically on actions taken to prevent or minimize occurrence of missing data in the future.

EPA acknowledges the point made by the commenters that most facilities subject to the rule do not use CEMS, and therefore, this fact can not be used as a justification for removing requirements related to minimizing future occurrence. Further, EPA agrees that information on duration would likely be collected when following the applicable missing data procedures. Nevertheless, based on the preceding discussion, EPA has concluded that sufficient data will be available on missing data through the required reporting of total number of hours in the year that missing data are used for each data element (per 40 CFR 98.3(c)(8)), and the recordkeeping requirements on cause of the event and actions taken to restore malfunctioning equipment. EPA has determined that requiring collection and retention of additional data on duration and actions taken to prevent or minimize occurrence

in the future is not necessary under the reporting program at this time.

F. Subpart A—General Provisions: Other Technical Corrections and Amendments

1. Summary of Final Amendments and Major Changes Since Proposal

We are making several additional amendments to subpart A, as follows.

We are making technical corrections to 40 CFR 98.3(c)(4)(i) through (c)(4)(iii) and (c)(4)(vi) to clarify that facilities must report GHG emissions from all applicable source categories, which includes general stationary fuel combustion, miscellaneous carbonates and any other source category covered by Part 98. This is consistent with the language in the 2009 final rule which required facilities to report emissions from all applicable source categories in subparts C through JJ. In a recent final rule (July 12, 2010, 75 FR 39736) we updated 40 CFR 98.2 to remove the lists of source categories covered by the rule and replace the list with Tables, specifically Table A–3 and Table A–4 of this chapter. This change was merely a reorganization and did not change applicability under the rule. The reformatting from lists to tables would enable EPA to add source categories in the future, and therefore add new subparts to the rule, without having to update all language referring to “subparts C through JJ.” In finalizing that rule, we made the appropriate changes to 40 CFR 98.2 indicating facilities must report GHG emissions from stationary fuel combustion sources, miscellaneous use of carbonates and all applicable source categories in Table A–3 and Table A–4. However, only the references to Table A–3 and Table A–4 were carried over to 40 CFR 98.3(c), which might suggest that facilities did not have to report emissions from general stationary combustion, because combustion is not in Table A–3 or Table A–4. We are therefore amending 40 CFR 98.3(c) to clarify that facilities must also report emissions from general stationary combustion and miscellaneous use of carbonates.

We are amending 40 CFR 98.3(c)(5)(i) to clarify that for the purposes of meeting the requirements of this paragraph, suppliers of industrial fluorinated GHGs only need to calculate and report GHG emissions in mtCO_2e for those fluorinated GHGs that are listed in Table A–1. Suppliers of industrial fluorinated GHGs do not need to calculate and report GHG emissions in metric tons CO_2 equivalents (mtCO_2e) for fluorinated GHGs not listed in Table A–1. However, it is important to note that suppliers are still required to report

these gases under 40 CFR 98.3(c)(5)(ii) (in metric tons of GHG).

We are amending 40 CFR 98.3(d)(3) to correct the year in which reporters that submit an abbreviated report for 2010 must submit a full report, from 2011 to 2012. The full report submitted in 2012 will be for the 2011 reporting year.

We are amending 40 CFR 98.3(f) to correct the cross-reference from “§ 98.3(c)(8)” to “§ 98.3(c)(9).” We are amending 40 CFR 98.3(g)(5)(iii) to correct a spelling error.

We are amending the elements required with a certificate of representation under 40 CFR 98.4(i)(2) to include organization name (company affiliation-employer). We are also adding the same element to the delegation by designated representative and alternate designated representative under 40 CFR 98.4(m)(2). Part 98 and the amendments do not require the designated representative, alternate designated representative, or agent to be an employee of the reporting entity. If a designated representative further delegates their authority to an agent the agent gains access to all data for that facility or supplier. To underline the importance of granting access to the correct person, EPA requires the designated representative (or alternate) to confirm each agent delegation. Adding organization name to the certificate of representation and notice of delegation adds a level of assurance to the confirmation process.

Finally, we are amending 40 CFR 98.6 (Definitions) and 40 CFR 98.7 (What standardized methods are incorporated by reference into this part?). We are adding or changing several definitions to subpart A, which are needed to clarify terms used in other subparts of Part 98.

We are amending the definitions of several terms in 40 CFR 98.6:

- Bulk natural gas liquid
- Distillate fuel oil
- Fossil fuel
- Fuel gas
- Municipal solid waste or MSW
- Natural gas
- Natural gas liquids, and
- Standard conditions

Bulk natural gas liquid. We are amending the definitions of “bulk natural gas liquid or NGL” and “natural gas liquids (NGL)” by removing the phrase “lease separators and field facilities” for enhanced clarity. We have retained the words “or other methods” in both definitions because the list of separation processes in the definitions (absorption, condensation, adsorption) is not exhaustive, and other separation/extraction processes may be employed at some facilities. We do not wish to

exclude the reporting of emissions associated with products separated/extracted by means not explicitly stated in the rule.

Distillate fuel oil. We are expanding the definition of “Distillate fuel oil” to include kerosene-type jet fuel.

Fossil fuel. We are amending the definition of fossil fuel, as proposed, to read, “Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for purpose of creating useful heat.” This amendment finalizes the same definition of fossil fuel that was originally proposed in April 2009 (74 FR 16621), but was subsequently amended in the final Part 98 (74 FR 56387). The change is not intended to have any impact on coverage of greenhouse gases under the GHG Reporting Program.

Fuel gas. We are amending the definition of fuel gas to clarify that it includes only gas generated at refineries or petrochemical processes subject to subpart X and to remove the phrase “or similar industrial process unit.” For a fuel explanation of this final change, please see the Comments and Response discussion under Section II.G of this preamble.

Municipal solid waste. We are amending the definition of municipal solid waste to be similar to, but not exactly the same as, the definition of “municipal solid waste” in subpart Ea of the NSPS regulations (40 CFR 60.51a). The amended definition explains what is meant by “household waste,” “commercial/retail waste,” and “institutional waste.” Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. 6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

Natural gas. We are finalizing the definition of natural gas to remove any specifications regarding Btu value or methane content. The final definition

reads, "Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. Natural gas may be field quality or pipeline quality." For a full explanation of this final change, please see the Comments and Response discussion under this section of the preamble.

Standard conditions. For consistency across the rule, and to reflect typical operating procedures at various types of industries covered by 40 CFR part 98, we are amending the definition of standard conditions to mean either 60 or 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

We are adding definitions of the following terms to 40 CFR 98.6 to address the large number of questions received requesting clarification on the meaning of these terms:

- Agricultural by-products,
- Primary fuel,
- Solid by-products,
- Used oil, and
- Wood residuals.

We received no comments on the definitions of "Agricultural by-products," "Primary fuel," and "Solid by-products." Therefore, these definitions have been finalized, as proposed. For the purposes of Part 98, "Agricultural by-products" includes the parts of crops that are not ordinarily used for food (e.g., corn straw, peanut shells, pomace, etc.). "Primary fuel" is defined as the fuel that contributes the greatest percentage of the annual heat input to a combustion unit. "Solid by-products" includes plant matter such as vegetable waste, animal materials/wastes, and other solid biomass, except for wood, wood waste and sulphite lyes (black liquor).

We proposed to add the term "waste oil" to Table C-1 but we received comment use of the term "waste oil" could result in used oil being classified as hazardous waste. We have therefore changed the term to "used oil." Used oil has been added to Table C-1 as a new fuel type, and is defined as a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of handling or use, such that the oil cannot be used for its original purpose. Used oil consists primarily of automotive oils (e.g., used motor oil, transmission oil, hydraulic fluids, brake fluid, etc.) and industrial oils (e.g., industrial engine oils, metalworking oils, process oils, industrial grease, etc.). For a full explanation of this final change, please see the Comments and Response discussion under this section of the preamble.

The definition of "wood residuals" has been finalized similar to the proposal, but EPA has also specifically included trim, sander dust, and sawdust from wood products manufacturing (including resinated wood product residuals) in the final definition.

We are amending 40 CFR 98.7 (Incorporation by reference) to accommodate changes in the standard methods that are allowed by other subparts of Part 98. The rationale for any additions or deletions of methods in a particular subpart is discussed in the relevant subpart.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

- Not adopting the proposed amendments to 40 CFR 98.3(c)(1) to report a facility or supplier ID number.
- Clarifying the definition of municipal solid waste. Clarifying that separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes, clean wood, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. 6921, are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.
- Finalizing the definition of natural gas to remove any specifications regarding Btu value or methane content.
- Amending the definition of standard conditions to provide two alternatives.
- Replacing the term "waste oil" with "used oil."
- Amending the definition of "wood residuals" to include trim, sander dust and sawdust from wood products manufacturing, including resinated wood product residuals.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the

Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: Several commenters objected to the proposed definition of municipal solid waste or MSW. One commenter in particular pointed to the regulatory history of the definition in 40 CFR 60, subpart Ea, indicating that some of the materials excluded by the proposed definition under 40 CFR part 98 are often included in MSW. According to the commenter, some of the exclusions in subpart Ea were added to the definition to provide an exemption to certain sources that combust materials such as used oil or wood pellets separately. By excluding materials often considered to be part of MSW, the commenter expressed concern that the proposed definition of MSW in 40 CFR part 98 might force some municipal waste combustors who considered themselves to be combusting MSW and would therefore otherwise be allowed to use Tier 2, to not meet the definition of MSW under 40 CFR part 98 and therefore have to install CEMS and use the Tier 4 methodology to quantify CO₂ emissions.

Response: EPA proposed to amend the definition of MSW to provide greater clarity on what is included as MSW. Several questions were raised during implementation of the GHGRP because the definition of MSW in the final Part 98 rule was too generic and did not define terms such as "house, commercial/retail, and institutional waste." To clarify the definition, EPA sought to use another EPA definition of the term, and did not intend to push some municipal waste combustors into a higher tier. Based on supplementary information provided by the commenter (please refer to EPA-HQ-OAR-2008-0508), the final definition of MSW includes materials that should not have been excluded, and clarifies that when these materials are extracted from MSW and combusted separately, they are not classified as MSW.

Comment: Two commenters on the definition of "Natural gas" pointed out that not all natural gas (particularly field gas) can consistently meet the proposed specifications. The commenters were concerned that EPA's proposal to include specifications that natural gas must be composed of at least 70 percent methane by volume or have a high heat value between 910 and 1,150 Btu per standard cubic foot would be problematic for subpart W, when finalized, because these ranges could exclude field gas.

Response: The definition of natural gas in the final rule caused significant confusion because it included not only

naturally occurring mixtures of hydrocarbons, but also fuels such as field gas, process gas and fuel gas. We proposed to change the definition of "natural gas" to include specifications on the methane content and a range of Btu values that must be achieved before the gas can be referred to as "natural gas." Clarifying the definition of natural gas is important, particularly given that it is a fuel in Table C-1 and if an owner or operator burns a fuel outside the range of the specifications, then they could be pushed into Tier 3 if any unit has a maximum rated heat input capacity greater than 250 million British thermal units per hour (mmBtu/hr).

Based on the comments received we have decided to finalize the definition of natural gas without any specifications regarding minimum or maximum Btu values or a minimum methane content. Although the commenters were concerned specifically about the implications of the definition of natural gas for the oil and gas industry, where the fuels combusted can often fall outside the listed specifications thereby potentially forcing them into Tier 3, these concerns did not weigh heavily into our determination to remove the specifications. Rather, we considered that most facilities subject to subpart C only typically burn natural gas within the proposed specifications. For these facilities, it was not necessary to list specifications, because most would already fall into the specifications we had proposed. Further, we were concerned that by introducing specifications to the definition of natural gas we could inadvertently push a small number of owners or operators into Tier 3, if they have been combusting a fuel outside that range.

It is true that facilities in the oil and gas industry are more likely to combust gas outside the listed specifications (e.g., field gas). However, facilities in the oil and gas industry will be subject to the reporting requirements under subpart W beginning with the 2011 reporting year. The concerns raised by the commenters with respect to calculating combustion-related emissions from natural gas were explicitly considered within the context of subpart W.

Comment: One commenter brought to our attention that the term "used oil" is more appropriate than "waste oil." According to the commenter, the term "waste oil" could result in used oil being classified as hazardous waste rather than traditional fuel, and might bring the Resource Conservation and Recovery Act program into view.

Response: Without indicating whether we agree with the commenter's concern

or not, we have decided to avoid potential complication or confusion and have replaced the term "waste oil" with "used oil" in the final rule.

Comment: We received two comments on the definition of "wood residuals." Both commenters requested that the definition explicitly include trim, sander dust and sawdust from wood products manufacturing, including resinated wood product residuals because they were concerned that the proposed definition was too broad and it was not clear if these products were included.

Response: We agree with the commenter. We did not intend to exclude these types of products from the definition of wood residuals and agree that these terms should be included in the definition in order to provide clarity.

Comment: Several commenters expressed concern about EPA's proposal to add a reporting requirement for facility ID. Two commenters suggested that EPA provide a separate public comment period for including a facility ID reporting requirement, and in that proposal, include a specific mechanism for assigning the ID numbers.

Response: Although we maintain that assigning a unique ID number to each facility or supplier, for administrative purposes, is important to facilitate program implementation, we have decided it is not necessary to finalize this reporting requirement at this time, given the concerns raised by the commenters. We will consider this issue further for future rulemakings. Note that we are still finalizing the technical clarification in 40 CFR 98.3(c)(1) that it is the physical street address of the facility or supplier that must be reported.

G. Subpart C—General Stationary Fuel Combustion

1. Summary of Final Amendments and Major Changes Since Proposal

Numerous issues have been raised by owners and operators in relation to the requirements in subpart C for general stationary fuel combustion. The issues being addressed by the final amendments include the following:

- Definition of the source category.
- GHGs to report.
- Calculating GHG emissions.
- Natural gas consumption expressed in therms.
- Use of Equation C-2b.
- Categories of gaseous fuels.
- Use of mass-based gas flow meters.
- Site-specific stack gas moisture content values.

- Determining emissions from an exhaust stream diverted from a CEMS monitored stack.

- Biomass combustion in Part 75 units using the CO₂ calculation methodologies in 40 CFR 98.33(a)(5).

- Use of Tier 3.
- Tier 4 monitoring threshold for units that combust MSW.
- Applicability of Tier 4 to common stack configurations.
- Starting dates for the use of Tier 4.
- Methane (CH₄) and nitrous oxide (N₂O) calculations.

- CO₂ emissions from sorbent.

- Biogenic CO₂ emissions from biomass combustion.

- Fuel sampling for coal and fuel oil.

- Tier 3 sampling frequency for gaseous fuels.

- GHG emissions from blended fuel combustion.

- Use of consensus standard methods.

- CO₂ monitor span values.

- CEMS data validation.

- Use of American Society of Testing and Materials (ASTM) Methods D7459–08 and D6866–08.

- Electronic data reporting and recordkeeping.

- Common stack reporting option.

- Common fuel supply pipe reporting option.

- Table C-1 default HHV and CO₂ emission factors.

- Table C-2 default CH₄ and N₂O emission factors.

Definition of the source category. We are adding new paragraph 40 CFR 98.30(d), clarifying that the GHG emissions from a pilot light need not be included in the emissions totals for the facility. A pilot light is a small auxiliary flame that simply ignites the burner of a combustion process in a boiler, turbine, or other fuel combustion device, and is not used to produce electricity or steam, or provide useful energy to an industrial process, or reduce waste by removing combustible matter.

GHGs to report. We are amending 40 CFR 98.32 to clarify that CO₂, CH₄, and N₂O mass emissions from a stationary fuel combustion unit do not need to be reported under subpart C if such an exclusion is indicated elsewhere in subpart C.

Calculating GHG emissions. We are amending the introductory text of 40 CFR 98.33(a) to provide additional detail and clarify who may (or must) use the calculation methods in the subsequent paragraphs to calculate and report GHG emissions. Specifically, we are amending this text to point out that certain sources may use the methods in 40 CFR part 75 to calculate CO₂ emissions, if they are already using part

75 to report heat input data year-round under another CAA program. The introductory text of 40 CFR 98.33(a) is also being amended to clarify the reporting of CO₂ emissions from biomass combustion when a unit combusts both biomass and fossil fuels.

Natural gas consumption expressed in therms. We are amending 40 CFR 98.33(a)(1) by adding two new equations to Tier 1. When natural gas consumption is expressed in therms, Equation C-1a enables sources to calculate CO₂ mass emissions directly from the information on the billing records, without having to request or obtain additional data from the fuel suppliers. We are also allowing Equation C-1a to be used for units of any size when the fuel usage information on natural gas billing records is expressed in units of therms. A new paragraph, (b)(1)(v), has been added to 40 CFR 98.33 to reflect this. Section 98.36(e)(2)(i) is also amended to allow gaseous fuel consumption to be reported in units of therms.

Equation C-1b has been added to Tier 1 to accommodate situations in which the fuel usage information on gas billing records is expressed in mmBtu. We are also adding two new equations to 40 CFR 98.33(c), *i.e.*, Equations C-8a and C-8b, for calculating CH₄ and N₂O emissions when the fuel usage information on natural gas billing records is in units of therms or mmBtu.

Use of Equation C-2b. We are amending 40 CFR 98.33(a)(2)(ii), to require calculation of a weighted HHV, using Equation C-2b, only for individual Tier 2 units with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr, and for groups of units that contain at least one unit of that size. For Tier 2 units smaller than 100 mmBtu/hr and for aggregated groups of Tier 2 units under 40 CFR 98.36(c)(1) in which all units in the group are smaller than 100 mmBtu/hr, we are allowing reporters to use either an annual arithmetic average HHV or an annual fuel-weighted average HHV in Equation C-2a.

Categories of gaseous fuels. We have revised 40 CFR 98.34(a)(2)(iii) by replacing the term “fossil fuel-derived gaseous fuels” with a more inclusive term, *i.e.*, “gaseous fuels other than natural gas.” Corresponding changes to Table C-1 were also made for consistency, placing blast furnace gas, coke oven gas, fuel gas, and propane in a new category, “Other fuels (gaseous).”

Use of mass-based gas flow meters. The Tier 3 CO₂ emissions calculation methodology in 40 CFR 98.33(a)(3) allows reporters to use flow meters that measure mass flow rates of liquid fuels

to quantify fuel consumption, provided that they (the reporters) determine the density of the fuel and convert the measured mass of fuel to units of volume (*i.e.*, gallons), for use in Equation C-4. In response to a number of requests, we are amending 40 CFR 98.33(a)(3)(iv), to conditionally allow reporters to use flow meters that measure mass flow rates of gaseous fuels for Tier 3 applications, as well as for liquid fuels. A reporter wanting to use this option will have to measure the density of the gaseous fuel, either with a calibrated density meter or by using a consensus standard method or standard industry practice, in order to convert the measured mass of fuel to units of standard cubic feet, for use in Equation C-5.

Site-specific stack gas moisture content values. We are amending 40 CFR 98.33(a)(4)(iii) to allow the use of site-specific moisture constants under the Tier 4 methodology. The site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in stack gas moisture content associated with different process operating conditions. Generally, for each site-specific default moisture percentage, at least nine runs are required using EPA Method 4—Determination of Moisture Content In Stack Gases (40 CFR part 60, appendix A-3). Each site-specific default moisture value would be calculated by taking the arithmetic average of the Method 4 runs. Moisture data from the relative accuracy test audit (RATA) of a CEMS could be used for this purpose. The final rule does allow the site-specific moisture default values to be based on fewer than nine Method 4 runs in cases where moisture data from the RATA of a CEMS are used to derive the default value and the applicable regulation allows a single moisture run to represent two or more RATA runs.

Each site-specific moisture default value must be updated at least annually and whenever the reporter determines the current value is non-representative due to changes in unit or process operation. The updated moisture value must be used in the subsequent CO₂ emissions calculations.

Determining emissions from an exhaust stream diverted from a CEMS monitored stack. We are finalizing amendments to 40 CFR 98.33(a)(4) by adding a new paragraph, (a)(4)(viii), to address the determination of CO₂ mass emissions from a unit subject to the Tier 4 calculation methodology when a portion of the flue gases generated by

the unit exhaust through a stack that is not equipped with a CEMS to measure CO₂ emissions (herein referred to as an “unmonitored stack”). The final amendments require annual emission testing of a diverted gas stream to be performed at a set point that best represents normal operation, using EPA Methods 2 and 3A and (if moisture correction is necessary) Method 4. A CO₂ mass emission rate is calculated from the test results. If, over time, flow rate of the diverted stream varies little from the tested flow rate, then the annual CO₂ mass emissions for the diverted stream (which must be added to the CO₂ mass emissions measured at the main stack) are determined simply by multiplying the CO₂ mass emission rate from the emission testing by the number of operating hours in which a portion of the flue gas was diverted from the main flue gas exhaust system. However, if the flow rate of the diverted stream varies significantly over the reporting year, the owner or operator must either perform additional stack testing or use the best available information (*e.g.*, fan settings and damper positions) and engineering judgment to estimate the CO₂ mass emission rate at a minimum of two additional set points, to represent the variation across the normal operating range. Then, the most appropriate CO₂ mass emission rate must be applied to each hour in which a portion of flue gas is diverted from the main exhaust system. The procedures used to determine the annual CO₂ mass emissions for the diverted stream must be documented in the GHG monitoring plan.

Biomass combustion in Part 75 units using the CO₂ calculation methodologies in 40 CFR 98.33(a)(5).

We are amending 40 CFR 98.33(a)(5)(iii)(D) to redesignate it as 40 CFR 98.33(a)(5)(iv). This is to correct a paragraph numbering error in subpart C, because this paragraph applies to all of 40 CFR 98.33(a)(5) and not just to 40 CFR 98.33(a)(5)(iii).

We had proposed to amend 40 CFR 98.33(c) in subpart A and 40 CFR 98.33(a)(5) to clarify that the separate reporting of biogenic CO₂ is optional for units that are not subject to the Acid Rain Program, but are using 40 CFR part 75 methodologies to calculate CO₂ mass emissions, as described in 40 CFR 98.33(a)(5)(i) through (a)(5)(iii). After considering the comments received on this proposal and other information (*see* EPA-HQ-OAR-2008-0508), however, we are finalizing language which makes it clear that reporting of biogenic CO₂ emissions from these units is optional for reporting year 2010, and mandatory

thereafter. Please see the discussion in Section II.C of this preamble regarding separate reporting of biogenic emissions for units subject to 40 CFR part 75.

Use of Tier 3. We are amending 40 CFR 98.33(b)(3)(iii) to clarify that the paragraph applies also to common pipe configurations where at least one unit served by the common pipe has a heat input capacity greater than 250 mmBtu/hr.

We are also adding a new paragraph, (b)(3)(iv), to 40 CFR 98.33, requiring Tier 3 to be used when specified in another subpart of Part 98, regardless of unit size. For example, subpart Y requires certain units that combust fuel gas to use Equation C-5 in subpart C (which is the Tier 3 equation for gaseous fuel combustion) to calculate CO₂ mass emissions, without regard to unit size.

Tier 4 monitoring threshold for units that combust MSW. We are amending 40 CFR 98.33(b)(4)(ii)(A) to change the Tier 4 monitoring threshold from 250 tons MSW per day to 600 tons MSW per day, based on analysis that this value is approximately equivalent to the 250 mmBtu/hr Tier 4 heat input threshold for other large stationary combustion units. Units less than 600 tons MSW per day that do not meet the requirements in 40 CFR 98.33(b)(4)(iii) are allowed to use Tier 2 to calculate CO₂ mass emissions (specifically, Equation C-2c).

Applicability of Tier 4 to common stack configurations. We are amending 40 CFR 98.33(b)(4) by adding provisions to clarify how the Tier 4 criteria apply to common stack configurations. Paragraph (b)(4)(i) is expanded to include monitored common stack configurations that consist of stationary combustion units, process units, or both types of units. A new paragraph, (b)(4)(iv) is also added describing the following three distinct common stack configurations to which Tier 4 might apply.

The first, most basic configuration is one in which the combined effluent gas streams from two or more stationary fuel combustion units are vented through a monitored common stack (or duct). In this case, Tier 4 applies if the following conditions are met:

- There is at least one large unit in the configuration that has a maximum rated heat input capacity greater than 250 mmBtu/hr or an input capacity greater than 600 tons/day of MSW (as applicable).
- At least one large combustion unit in the configuration meets the conditions of 40 CFR 98.33(b)(4)(ii)(A) through (b)(4)(ii)(C).
- The CEMS installed at the common stack (or duct) meets all of the

requirements of 40 CFR 98.33 (b)(4)(ii)(D) through (b)(4)(ii)(F).

Tier 4 also applies when all of the combustion units in the configuration are small (not greater than 250 mmBtu/hr or 600 tons/day of MSW), if at least one of the units meets the conditions of 40 CFR 98.33(b)(4)(iii).

The second configuration is one in which the combined effluent gas streams from a stationary combustion unit and a process or manufacturing unit are vented through a common stack or duct. Many subparts of Part 98 describe this situation (*see* subparts F, G, K, Q, Z, BB, EE, and GG). In this case, the use of Tier 4 is required if the stationary combustion unit and the monitors installed at the common stack or duct meet the applicability criteria of 40 CFR 98.33(b)(4)(ii) or 98.33(b)(4)(iii). If multiple stationary combustion units and a process unit (or units) are vented through a common stack or duct, Tier 4 is required if at least one of the combustion units and the monitors installed at the common stack or duct meet the conditions of 40 CFR 98.33(b)(4)(ii) or 98.33(b)(4)(iii).

The third configuration is one in which the combined effluent streams from two or more process or manufacturing units are vented through a common stack or duct. In this case, if any of these units is required to use Tier 4 under an applicable subpart of Part 98, the owner or operator can either monitor the CO₂ mass emissions at the Tier 4 unit(s) before the effluent streams are combined together, or monitor the combined CO₂ mass emissions from all units at the common stack or duct. However, if it is not feasible to monitor the individual units, the combined CO₂ mass emissions will have to be monitored at the common stack or duct, using Tier 4.

Starting dates for the use of Tier 4. In the October 30, 2009 final rule, 40 CFR 98.33(b)(5) of subpart C states that units that are required to use the Tier 4 methodology must begin using it on January 1, 2010 if all required CEMS are in place. Otherwise, use of Tier 4 begins on January 1, 2011, and Tier 2 or Tier 3 may be used to report CO₂ mass emissions in 2010. We are amending 40 CFR 98.33(b)(5) to clarify that sources can begin monitoring CO₂ emissions data prior to January 1, 2011 from CEMS that successfully complete certification testing in 2010. Note that changes in methodology during a reporting year are allowed by Part 98, and must be documented in the annual GHG emissions report (*see* 40 CFR 98.3(c)(6)).

This revision will allow sources to discontinue using Tier 2 or 3 and begin reporting their 2010 emissions under

Tier 4 as of the date on which all required certification tests are passed. Data recorded during the certification test period for a CEMS can also be used for Part 98 reporting, provided that: All required certification tests are passed in sequence, with no test failures; and no unscheduled maintenance or repair of the CEMS is required during the test period.

We are also amending 40 CFR 98.33(b)(5) by adding a new paragraph, (b)(5)(iii), to address situations where the owner or operator of an affected unit that has been using Tier 1, 2, or 3 to calculate CO₂ mass emissions makes a change that triggers Tier 4 applicability by changing: The primary fuel, the manner of unit operation, or the installed continuous monitoring equipment. In such cases, the owner or operator will be required to begin using Tier 4 no later than 180 days from the date on which the change is implemented. This allows adequate time for the owner or operator to obtain and/or certify any of the required Tier 4 continuous monitors.

Methane and nitrous oxide calculations. Today's amendments remove the term "normal operation" from 40 CFR 98.33(c)(4)(i) and (c)(4)(ii). Therefore, calculation of CH₄ and N₂O emissions is simply required for each Table C-2 fuel combusted in the unit during the reporting year.

We are also further amending 40 CFR 98.33(c)(4)(ii), to allow additional reporting flexibility for certain units that combust more than one type of fuel; specifically, for units that report heat input data to EPA year-round using part 75 CEMS. Under the final amendments to 40 CFR 98.33(c)(4)(ii), 40 CFR part 75 units that use the worst-case F-factor reporting option can attribute 100 percent of the unit's annual heat input to the fuel with the highest F-factor, as though it were the only fuel combusted during the report year.

For Tier 4 units, the requirement to use the best available information to determine the annual heat input from each type of fuel is being retained in 40 CFR 98.33(c)(4)(i), but we are also now allowing it under 40 CFR 98.33(c)(4)(ii)(D) as an alternative for part 75 units, in cases where fuel-specific heat input values cannot be determined solely from the part 75 electronic data reports.

Carbon dioxide emissions from sorbent. We are amending 40 CFR 98.33(d) to make it more generally applicable to different types of CO₂-producing sorbents. The term "R" is redefined as the number of moles of CO₂ released upon capture of one mole of acid gas. When the sorbent is CaCO₃, the

value of R is 1.00. For other CO₂-producing sorbents, a specific value of R is determined by the reporting facility from the chemical formula of the sorbent and the chemical reaction with the acid gas species that is being removed.

Biogenic CO₂ emissions from biomass combustion.

The title and introductory text of 40 CFR 98.33(e) are being amended to more precisely define the requirements for reporting biogenic CO₂ emissions. In general, biogenic CO₂ emissions reporting is required only for the combustion of the biomass fuels listed in Table C-1 and for municipal solid waste (which consists partly of biomass and partly of fossil fuel derivatives).

We are also amending 40 CFR 98.33(e) to describe three cases in which reporters may not need to report biogenic CO₂ emissions separate from total CO₂ emissions, for units that combust biomass:

1. If a biomass fuel is not listed in Table C-1 and is combusted in a unit that is not required to use Tier 4, a reporter is not required to separately report the biogenic CO₂ emissions from combustion of that fuel unless:

- The fuel is combusted in a large unit (greater than 250 mmBtu/hr heat input capacity).
- The biomass fuel accounts for 10 percent or more of the annual heat input to the unit.

In that case, according to 40 CFR 98.33(b)(3)(iii), Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO₂ emissions.

2. If a unit is subject to subpart C or D and uses the CO₂ mass emissions calculation methodologies in 40 CFR part 75 to satisfy the Part 98 reporting requirements, the reporter has the option to report biogenic CO₂ emissions for the 2010 reporting year, but is required to report them thereafter.

3. For the combustion of tires, which are also partly biogenic (typically about 20 percent biomass, for car and truck tires), the reporter has the option, but not the requirement, to separately report the biogenic CO₂ emissions, by following the applicable provisions in 40 CFR 98.33(e).

No comments were received on the proposal to make biogenic CO₂ emissions reporting optional for the combustion of tires, and the proposal has been finalized without modification. However, tire-derived fuel has a biomass component, and perhaps it should be treated in the same manner as MSW, which is also partly biogenic. A number of units that are subject to Part

98 combust tires as the primary fuel or as a secondary fuel. Therefore, we are considering whether these units should be required to account for their biogenic CO₂ emissions. However, before making this mandatory we intend to open it to notice and comment in a future rulemaking.

We are amending 40 CFR 98.33(e)(1) by removing the restriction against using Tier 1 to calculate biogenic CO₂ emissions on units that use CEMS to measure the total CO₂ mass emissions. However, the use of Tier 1 is not allowed for calculating biogenic CO₂ emissions for combustion of MSW, as originally specified in 40 CFR 98.33(e)(1) of subpart C, and is also not allowed for the combustion of tires, if biogenic CO₂ emissions are calculated for tires.

We are amending the methodology in 40 CFR 98.33(e)(2), which is specifically for units using a CEMS to measure CO₂ mass emissions, by limiting it to cases where the CO₂ emissions measured by the CEMS are solely from combustion, *i.e.*, the stack gas contains no additional process CO₂ or CO₂ from sorbent; and prohibiting its use if the unit combusts MSW or tires.

For sources that combust MSW, we are amending 40 CFR 98.33(e)(3) to require, except as provided below, the quarterly use of ASTM methods D7459-08 and D6866-08, as described in 40 CFR 98.34(d), when any MSW is combusted either as the primary fuel or as the only fuel with a biogenic component. We are also amending 40 CFR 98.33(e)(3) to allow the ASTM methods to be used, as described in 40 CFR 98.34(e), for any unit in which biogenic (or partly biogenic) fuels, and non-biogenic fuels are combusted, in any proportions.

In response to comments, we have added an alternative calculation methodology for biogenic CO₂ emissions from the combustion of MSW and/or tires, which may be used when the total contribution of these fuels to the unit's heat input is 10 percent or less. If a unit combusts both MSW and tires and the reporter exercises the option not to separately report biogenic CO₂ emissions from the tires, the alternative calculation methodology may still be used for the MSW, provided that the contribution of MSW to the unit's total heat input does not exceed 10 percent. The methodology may also be used for small, batch incinerators that burn no more than 1,000 tons of MSW per year.

Units that qualify for and elect to use the alternative methodology will use Tier 1 to calculate the total annual CO₂ emissions from the combustion of the MSW or tires, and multiply the result by

an appropriate default factor that represents the biomass fraction of the fuel, to obtain an estimate of the annual biogenic CO₂ emissions. Based on additional background research conducted, we have concluded that reasonable default factors are 0.20 for tires and 0.60 for MSW (please refer to the Background Technical Support Document—Revision of Certain Provisions).

We are also amending 40 CFR 98.33(e) to delete and reserve 40 CFR 98.33(e)(4) and the related subparagraphs. Although 40 CFR 98.33(e)(4) allowed the ASTM methods to be used to determine biogenic CO₂ emissions for various combinations of biogenic and fossil fuels, we are deleting and reserving that paragraph because the paragraph also included an unnecessary restriction, *i.e.*, it only applied to units that use CEMS to measure total CO₂ mass emissions. The amendments to 40 CFR 98.33(e)(3) described above will achieve the same intended purpose as paragraph (e)(4), without imposing this restriction, so paragraph (e)(4) is no longer needed.

We are amending 40 CFR 98.33(e)(5) so that it also applies to units that are using Tier 2 (Equation C-2a), as well as Tier 1 (Equation C-1), for calculating biogenic CO₂ mass emissions. The approach in 40 CFR 98.33(e)(5) for estimating solid biomass fuel consumption is equally applicable to units using those two equations to calculate biogenic CO₂ emissions. Equation C-2a applies when HHV data for a biomass fuel are available at the minimum frequency specified in 40 CFR 98.34(a)(2).

Finally, one commenter asked EPA to allow Part 75 units to calculate biogenic CO₂ emissions using the same general approach that is used in 40 CFR 98.33(c)(4)(ii) for the CH₄ and N₂O emissions calculations. This requires a heat input-based equation similar to Equation C-10 to be added to the rule. We find this request to be reasonable and have added a new paragraph, (e)(6), to 40 CFR 98.33(e). Paragraph (e)(6) provides the required equation, *i.e.*, Equation C-15a. In cases where (HI)_A, the fraction of unit heat input from combustion of the biomass fuel, cannot be determined from the information in Part 75 electronic data reports (*e.g.*, for units that measure the total CO₂ emissions with CEMS, if the “worst-case” F-factor option is used, or if biomass and fossil fuels with identical F-factors are combusted), facilities must use the “best available information” (as described in 40 CFR 98.33(c)(4)(ii)(C) and (c)(4)(ii)(D)) to determine (HI)_A.

Fuel sampling for coal and fuel oil. We are amending 40 CFR 98.34(a)(2), to clarify the frequency at which the HHV needs to be determined for different types of fuels.

First, we are amending 40 CFR 98.34(a)(2)(ii) to expand the list of fuels for which sampling of each fuel lot is sufficient to include other solid or liquid fuels that are delivered in lots.

Second, we are amending the definition of the term “fuel lot” in 40 CFR 98.34(a)(2)(ii), as it pertains to facilities that receive multiple deliveries of a particular type of fuel from the same supply source each month, either by truck, rail, or pipeline. The amendment clarifies that a fuel lot consists of all of the deliveries of that fuel for a given calendar month. Thus, for these facilities, the required HHV sampling has to be no more frequent than once per month. We did receive requests to clarify the meaning of the terms “type of fuel” and “supply source,” pertaining to the proposal to require only one monthly sample to represent multiple fuel deliveries. The final rule clarifies that for coal, the type of fuel refers to the coal rank (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the type of fuel refers to the grade number or classification of the oil (*e.g.*, No. 2 oil, No. 6 oil, jet-A fuel, *etc.*). The term “supply source” is not so easily defined. For the reasons set forth in the Response to Comments (Section II.G.2 of this preamble), we have chosen not to include a definition of “supply source” in the final rule.

Third, we are adding parallel language to 40 CFR 98.34(b)(3)(ii), the Tier 3 fuel sampling provisions for coal and fuel oil, for consistency with the revisions to 40 CFR 98.34(a)(2)(ii).

Finally, we are amending 40 CFR 98.34(a)(2)(ii) and 40 CFR 98.34(b)(3)(ii) to allow manual oil samples to be taken after each addition of oil to the storage tank. Daily manual sampling, flow-proportional sampling, and continuous drip sampling are also allowed. The final rule requires at least one sample to be obtained from each storage tank that is currently in service, and whenever oil is added, for as long as the tank remains in service. If multiple additions (*e.g.*, from multiple deliveries) are made on a given day, taking one sample after the final addition is sufficient. No sampling is required for addition of fuel to a tank that is out of service. Rather, a sample must be taken when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If the daily manual sampling option is implemented, sampling from a particular tank is required only on those days when oil

from that tank is combusted in the unit(s).

Tier 3 sampling frequency for gaseous fuels.

We are amending 40 CFR 98.34(b)(3)(ii)(E) to clarify that daily sampling of gaseous fuels other than natural gas and biogas for carbon content and molecular weight is only required where continuous, on-line equipment is in place; weekly sampling is required in all other cases.

GHG emissions from blended fuel combustion. One of the most frequently asked questions by the regulated community since publication of the October 30, 2009 final Part 98 is, “How does one calculate CO₂ mass emissions from the combustion of blended fuels?” Subpart C provided only limited guidance on this issue. We are now finalizing amendments to 40 CFR 98.34(a)(3), (b)(1)(vi), and (b)(3)(v) to clarify reporting requirements for calculating emissions from blended fuels. The amendments make a clear distinction between cases where the mass or volume of each fuel in the blend is accurately measured prior to mixing (*e.g.*, using individual flow meters for each component) and cases where the exact composition of the blend is not known. In the former case, the fact that the fuels are blended is of no consequence; because the exact quantity of each fuel in the blend is known, the CO₂ emissions from combustion of each component must be calculated separately. In the latter case, the blend is considered to be a distinct “fuel type,” and the reporter must measure its mass or volume and essential properties (*e.g.*, HHV, carbon content, *etc.*) at a prescribed frequency.

When the mass or volume of each individual component of a blend is not precisely known prior to mixing, the appropriate method used to calculate the CO₂ mass emissions from combustion of the blend is as follows. For smaller combustion units (heat input capacity not more than 250 mmBtu/hr), Tier 2 (or possibly Tier 1) can be used when all components of the blend are listed in Table C–1 of subpart C. In order to perform these CO₂ emissions calculations for the blend, a reasonable estimate of the percentage composition of the blend would be required, using the best available information (*e.g.*, from the typical or expected range of values of each component). A heat-weighted CO₂ emission factor must be calculated, using new Equation C–16. For Tier 1 applications, a heat-weighted default HHV must be determined, using new Equation C–17.

In cases where a fuel blend consists of a mixture of fuel(s) listed in Table C–1 and fuel(s) not listed in Table C–1, calculation of CO₂ and other GHG emissions from combustion of the blend is required only for the Table C–1 fuel(s), using the best available estimate of the mass or volume percentage(s) of the Table C–1 fuel(s) in the blend. In these cases, the use of Tier 1 is required, with modifications to certain terms in Equations C–17 and C–1, to account for the fact that the blend is not composed entirely of Table C–1 fuels. An example calculation is provided in 40 CFR 98.34(a)(3)(iv).

For larger combustion units (heat input capacity greater than 250 mmBtu/hr) that do not qualify to use Tier 1 or 2, the owner or operator must use Tier 3 to calculate the CO₂ mass emissions from combustion of a blended fuel. The mathematics for Tier 3 are simpler than for Tiers 1 and 2, since no default values are used in the calculations, and an estimate of the percentage composition of the blend is not required. To apply Tier 3, the only requirements are to accurately measure the annual consumption of the blended fuel and to determine its carbon content and (if necessary) molecular weight, at a prescribed frequency. By considering the blended fuel to be a distinct “fuel type,” in cases where that fuel is not listed in Table C–1, GHG emissions reporting is required in accordance with 40 CFR 98.33(b)(3)(iii), if the blended fuel (as opposed to each individual component of the blend) provides at least 10 percent of the annual heat input to a unit or group of units, and if the use of Tier 4 is not required.

To address the calculation of CH₄ and N₂O mass emissions from the combustion of blended fuels, we are adding a new paragraph, (c)(6), to 40 CFR 98.33. Calculation of CH₄ and N₂O emissions is required only for components of a blend that are listed in Table C–2 of subpart C.

If the mass or volume of each component of a blend is measured before the fuels are mixed and combusted, the existing CH₄ and N₂O mass emissions calculation procedures in 40 CFR 98.33(c)(1) through (5) must be followed for each component separately. The fact that the fuels are mixed prior to combustion is of no consequence in this case.

If the mass or volume of each individual component is not measured prior to mixing, a reasonable estimate of the percentage composition of the blend is required, based on the best available information, and the procedures in 40 CFR 98.33(c)(6)(ii) will be followed. First, the annual consumption of each

component fuel in the blend is calculated by multiplying the total quantity of the blend combusted during the reporting year by the estimated mass or volume percentage of that component. Next, the annual heat input from the combustion of each component is calculated by multiplying its annual consumption by the appropriate HHV (either the default HHV from Table C-1 or, if available, the measured annual average value). The annual CH₄ and N₂O mass emissions for each component must then be calculated using the applicable equation in 40 CFR 98.33(c), *i.e.*, Equation C-8, C-9a, or C-10. Finally, the calculated CH₄ and N₂O emissions are summed across all components, and these sums are reported as the annual CH₄ and N₂O mass emissions for the blend.

Use of consensus standard methods. We are amending 40 CFR 98.33(a)(3)(iv) and (a)(3)(v) to remove reference to specific standard methods and allow the use of standards from consensus-based organizations or industry standard practice. We are amending 40 CFR 98.34 to remove the specific ASTM and GPA method list for fuel sampling and analysis in 40 CFR 98.34(a)(6), to remove the list of American Gas Association (AGA) and American Society of Mechanical Engineers (ASME) methods for fuel meter calibration in 40 CFR 98.34(b)(4), and to delete the list of ASTM methods to determine carbon content and molecular weight in 40 CFR 98.34(b)(5). We are also redesignating 40 CFR 98.34(b)(5) as 40 CFR 98.34(b)(4), and amending newly designated 40 CFR 98.34(b)(4). Finally, we are amending 40 CFR 98.34(b)(1)(A) to remove the cross-reference to the fuel flow meter test methods listed in 40 CFR 98.34(b)(4). These amendments allow the owner or operator to use manufacturers' procedures, appropriate methods published by consensus-based standards organizations such as ASTM, ASME, American Petroleum Institute (API), AGA, ISO, *etc.*; or use industry-accepted practice. The methods used must be documented in the monitoring plan under 40 CFR 98.3(g)(5).

CO₂ monitor span values. The Tier 4 calculation method in 40 CFR 98.33(a)(4) requires a CO₂ concentration monitor and a stack gas flow rate monitor to measure CO₂ mass emissions. The CO₂ monitor must be certified and quality-assured according to one of the following: 40 CFR part 60, 40 CFR part 75, or an applicable State CEM program. When the part 60 option is selected, one of the required quality assurance (QA) tests of the CO₂ monitor is a cylinder gas audit (CGA). The CGA

checks the response of the CO₂ analyzer at two calibration gas concentrations, *i.e.*, one between 5 and 8 percent CO₂ and one between 10 and 14 percent CO₂. These CO₂ concentration levels are appropriate for most stationary combustion applications. However, when CO₂ emissions from an industrial process (*e.g.*, cement manufacturing) are combined with combustion CO₂ emissions, the resultant CO₂ concentration in the stack gas can be substantially higher than for the combustion emissions alone. In such cases, a span value of 30 percent CO₂ (or higher) may be required.

When the CO₂ span exceeds 20 percent CO₂, the CGA concentrations specified in Part 60 only evaluate the lower portion of the measurement scale and are no longer representative. Therefore, we are amending 40 CFR 98.34(c) by adding a new paragraph (c)(6), which allows the CGA of a CO₂ monitor to be performed using calibration gas concentrations of 40 to 60 percent of span and 80 to 100 percent of span, when the CO₂ span value is set higher than 20 percent CO₂.

CEMS data validation. In subpart C, 40 CFR 98.34(c) provides the monitoring and QA requirements for Tier 4. However, no criteria for hourly CEMS data validation were specified in the final rule. We are adding a new paragraph, (c)(7), to 40 CFR 98.34, which requires hourly CEMS data validation to be consistent with the sections of 40 CFR part 60 or part 75 cited in the preceding paragraph of this preamble. Alternatively, the hourly data validation procedures in an applicable State CEM program can be followed.

Use of ASTM Methods D7459-08 and D6866-08. Sections 98.34(d) and (e) of subpart C, respectively, outline procedures for quantifying biogenic CO₂ emissions for units that combust MSW and other units that combust combinations of fossil fuels and biomass. Flue gas samples are taken quarterly using ASTM Method D7459-08 and analyzed using ASTM Method D6866-08. We are amending 40 CFR 98.34(d) and (e), as discussed in the following paragraphs.

The amendments to 40 CFR 98.34(d) require the ASTM methods to be used when MSW is combusted in a unit, either as the primary fuel, or as the only fuel with a biogenic component, unless the unit qualifies for the alternative Tier 1 calculation methodology described above, under "Biogenic CO₂ emissions from biomass combustion." Quarterly sampling with ASTM Method D7459-08 is required for a minimum of 24 cumulative hours of sampling per quarter, except as provided below.

We are amending 40 CFR 98.34(e) to remove the restriction limiting the use of ASTM Methods D7459-08 and D6866-08 to units with CEMS. Rather, any unit that combusts combinations of fossil and biogenic fuels (or partly biogenic fuels, such as tires), in any proportions, is allowed to determine biogenic CO₂ emissions using the ASTM methods on a quarterly basis. At least 24 cumulative hours of sampling per quarter are required, except as provided immediately below.

We are adding an option to 40 CFR 98.34(d) and (e), allowing sources to demonstrate that 8 hours of sampling per quarter is sufficient. The demonstration requires a minimum of two 8-hour tests and one 24-hour test, performed under normal, stable operating conditions. The demonstration tests must be distinct, *i.e.*, no overlapping of the 8-hour and 24-hour test periods is permitted. If the average biogenic fraction obtained from the 8-hour tests is within ± 5 percent of the results from the 24-hour test, then, in subsequent quarters, the Method D7459-08 sampling time may be reduced to 8 hours. The results of the demonstration must be documented in the monitoring plan.

We are also amending 40 CFR 98.34(d) by adding an alternative to allow the owner or operator to collect an integrated sample by extracting a small amount of flue gas (1 to 5 cubic centimeters (cc)) during every unit operating hour in the quarter, in order to obtain a more representative sample for analysis.

Procedures for estimating missing data. We are amending 40 CFR 98.35(a) to clarify that the missing data procedures in 40 CFR part 75 are only to be followed by units that are in the Acid Rain Program and those that monitor and report emissions and heat input data year round. Units that only monitor and report during the ozone season must follow the missing data procedures in 40 CFR 98.35(b).

Electronic data reporting and recordkeeping. We are amending the data element lists in 40 CFR 98.36 by adding a number of essential data elements and eliminating or modifying others. The most significant revisions to the data element lists are summarized in the following paragraphs. We are also adding an alternative reporting option to 40 CFR 98.36(c) to reduce the reporting burden for certain facilities.

We are adding the reporting of methodology start and end dates in several places throughout 40 CFR 98.36(b), (c), and (d).

We are amending the data element lists in 40 CFR 98.36 to be consistent

with respect to reporting of emissions by fuel type and reporting of biogenic CO₂ emissions. Specifically, for clarity and consistency with the changes to 40 CFR 98.3(c), we have modified the amendments to 40 CFR 98.36(d)(1)(ii), (d)(1)(ix), (d)(2)(ii)(I), and (d)(2)(iii)(I) from the proposal. These sections state that for units subject to 40 CFR part 75, reporting of biogenic CO₂ emissions is optional only for the 2010 reporting year. Reporting of these emissions becomes mandatory starting with the 2011 reporting year.

We are removing 40 CFR 98.36(b)(10) to remove the requirement to report the customer meter number for units that combust natural gas.

We are finalizing requirements in 40 CFR 98.36(c)(1)(ii) that only the maximum rated heat input capacity of the largest unit in a group must be reported. We are also finalizing requirements for 98.36(c)(3) in a similar manner, for groups of units served by a common pipe.

We are amending 40 CFR 98.36 to remove the requirement to report the combined annual GHG emissions from fossil fuel combustion in metric tons of CO₂e (*i.e.*, the sum of the CO₂, CH₄, and N₂O emissions) by removing 40 CFR 98.36(b)(9), (c)(1)(ix), (c)(2)(viii), and (c)(3)(viii). These data elements were duplicative of requirements in subpart A.

We are amending 40 CFR 98.36(b), (c), and (d) to require reporting the fuel-specific annual heat input estimates, for the purpose of verifying the reported CH₄ and N₂O emissions. Also, we are amending 40 CFR 98.36(e)(2)(iv) to require reporting of the annual average HHV when measured HHV data are used to calculate CH₄ and N₂O emissions for a Tier 3 unit, in lieu of using a default HHV from Table C-1.

We are amending 40 CFR 98.36(b) and (d) to make the data elements reported under Tiers 1 through 4 consistent for the reporting of biogenic CO₂ emissions and CO₂ from fossil fuel combustion. Also, as previously noted in Section II.C of this preamble, the amendments to 40 CFR 98.36(d) state that reporting of biogenic CO₂ emissions is optional only for the 2010 reporting year for units using the CO₂ mass emissions calculation methods in 40 CFR part 75.

For units that use the Tier 4 methodology to calculate CO₂ mass emissions, we are amending 40 CFR 98.36(b)(7)(i) and (b)(7)(ii) (redesignated as 40 CFR 98.36(b)(9)(i) and (b)(9)(ii), respectively) and 40 CFR 98.36(c)(2)(vi) (redesignated as 40 CFR 98.36(c)(2)(viii)). The amendments to these sections require the annual “non-biogenic” CO₂ mass emissions to be

reported instead of reporting the annual CO₂ mass emissions from fossil fuel combustion.

We are adding a new alternative reporting option, under 40 CFR 98.36(c)(4). This new option applies to specific situations where a common liquid or gaseous fuel supply is shared between large combustion units such as boilers or combustion turbines (including Acid Rain Program units and other combustion units that use the methods in 40 CFR part 75 to calculate CO₂ mass emissions), and small combustion sources such as space heaters, hot water heaters, *etc.* In such cases, a source can simplify reporting by attributing all of the GHG emissions from combustion of the shared fuel to the large combustion unit(s), provided that:

- The total quantity of the shared fuel supply that is combusted during the report year is measured, either at the “gate” to the facility or at a point inside the facility, using a fuel flow meter, a billing meter or tank drop measurements; and
- On an annual basis, at least 95 percent of the shared fuel supply (by mass or volume) is burned in the large combustion unit(s) and the remainder of the fuel is fed to the small combustion sources.

Company records can be used to determine the percentage distribution of the shared fuel to the large and small units. Facilities using this reporting option are required to document in their monitoring plan which units share the common fuel supply and the method used to determine that the reporting option applies. For the small combustion sources, a description of the type(s) and approximate number of units involved is sufficient.

Finally, we are amending 40 CFR 98.36(e)(2)(iii) to simplify the recordkeeping requirements in cases where the results of fuel analyses for HHV are provided by the fuel supplier. Parallel language is added in a new paragraph, 40 CFR 98.36(e)(2)(v)(E), for the results of carbon content and molecular weight analyses received from the fuel supplier. In both cases, the owner or operator is required to keep records of only the dates on which the fuel sampling results are received, rather than keeping records of the dates on which the supplier’s fuel samples were taken (which may not be readily available).

Common stack reporting option. Section 98.36(c)(2) of subpart C allows subpart C stationary fuel combustion units that share a common stack or duct to use the Tier 4 Calculation Methodology to monitor and report the

combined CO₂ mass emissions at the common stack or duct, in lieu of monitoring each unit individually. However, 40 CFR 98.36(c)(2) does not address circumstances where at least one of the units sharing the common stack is not a subpart C stationary fuel combustion unit, but is subject to another subpart of 40 CFR part 98. In view of this, we are amending 40 CFR 98.36(c)(2) by extending the applicability of the common stack monitoring and reporting option to situations where off-gases from multiple process units or mixtures of combustion products and process off-gases are combined together and vented through a common stack or duct.

The amendments to 40 CFR 98.36(c)(2) apply not only to ordinary common stack or duct situations where the gas streams from multiple units are combined together, but also apply when combustion and/or process off-gas streams from a single unit (*e.g.*, from a kiln, furnace, petrochemical process unit, or smelter) are routed to a stack. To accommodate this variation on the concept of a common stack, 40 CFR 98.36(c)(2)(ii) is amended to require sources to report “1” as the “Number of units sharing the common stack or duct” where combustion and/or process emissions from a single unit are vented through the same stack or duct.

Finally, since the concept of maximum rated heat input capacity may not be applicable to certain types of process or manufacturing units, we are amending 40 CFR 98.36(c)(2)(iii), to require that the “combined maximum rated heat input capacity of the units sharing the common stack or duct” only be reported when all of the units sharing the common stack or duct are stationary fuel combustion units.

Common fuel supply pipe reporting option. Section 98.36(c)(3) of subpart C allows units that are served by a common fuel supply pipe to report the combined CO₂ emissions from all of the units in lieu of reporting CO₂ emissions separately from each unit. To use this reporting option, the total amount of fuel combusted in the units must be accurately measured with a flow meter calibrated according to the requirements in 40 CFR 98.34. Section 98.36(c)(3) also states that the applicable tier to use for this reporting option is based on the maximum rated heat input of the largest unit in the group.

We are amending 40 CFR 98.36(c)(3) as follows. First, the erroneous citation of “§ 98.34(a)” is corrected to read “§ 98.34(b).” Second, we are amending the requirement in 40 CFR 98.36(c)(3) to calibrate the fuel flow meter to the accuracy required by 40 CFR 98.34(b)

(which cross-references the accuracy specifications in 40 CFR 98.3(i)), so that this calibration requirement applies only when Tier 3 is the required tier for calculating CO₂ mass emissions. This is consistent with the final amendments to 40 CFR 98.3(i), where we clarify that the equipment used to generate company records under Tier 1 and 2 is not required to meet the calibration accuracy specifications of 40 CFR 98.3(i).

The applicable measurement tier for the common pipe option, according to subpart C, is based on the rated heat input capacity of the largest unit in the group. On the surface, this appears to mean that the use of Tiers 1 and 2 is restricted to common pipe configurations where the highest rated heat input capacity of any unit is 250 mmBtu/hr or less, and that Tier 3 is required if any unit has a maximum rated heat input capacity greater than 250 mmBtu/hr. In general, this is true. However, there is one exception in the current rule and we are amending the rule to add a second one. Section 98.33(b)(2)(ii) of the current rule allows the use of Tier 2 instead of Tier 3 for the combustion of natural gas and/or distillate oil in a unit with a rated heat input capacity greater than 250 mmBtu/hr. Today's rule adds a new paragraph, (b)(1)(v), to 40 CFR 98.33, allowing Tier 1 to be used when natural gas consumption is determined from billing records, and fuel usage on those records is expressed in units of therms or mmBtu. Therefore, we are also amending 40 CFR 98.36(c)(3) to reflect these two exceptions for common pipe configurations that include a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr.

Finally, we are amending the provision in 40 CFR 98.36(c)(3) regarding the partial diversion of a fuel stream such as natural gas that is measured "at the gate" to a facility (*e.g.*, using a calibrated flow meter or a gas billing meter). Subpart C specifies that when part of a fuel stream is diverted to a chemical or industrial process where it is used but not combusted, and the remainder of the fuel is sent to a group of combustion units, you may subtract the diverted portion of the fuel stream from the total quantity of the fuel measured at the gate before applying the common pipe methodology to the combustion units. We are amending the rule to expand this provision to include cases where the diverted portion of the fuel stream is sent either to a flare or to another stationary combustion unit (or units) on site, including units that use 40 CFR part 75 methodologies to calculate annual CO₂ mass emissions

(*e.g.*, Acid Rain Program units). Provided that the GHG emissions from the flare and/or other combustion unit(s) are properly accounted for according to the applicable subpart(s) of Part 98, you are allowed to subtract the diverted portion of the fuel stream from the total quantity of the fuel measured at the gate, and then apply the common pipe reporting option to the group of combustion units served by the common pipe, using the Tier 1, Tier 2, or Tier 3 calculation methodology (as applicable).

Table C-1. Table C-1 of subpart C provides default HHV values and default CO₂ emission factors for various types of fuel. We are finalizing several amendments to Table C-1; specifically, we have:

- Replaced the categories "fossil fuel-derived fuels (solid)" and "fossil fuel-derived fuels (gaseous)" with more inclusive terms, *i.e.*, "other fuels (solid)" and "other fuels (gaseous)." The "other fuels (solid)" category includes four fuels: plastics, municipal solid waste, tires, and petroleum coke. The "other fuels (gaseous)" category includes blast furnace gas, coke oven gas, propane gas, and fuel gas.

- Removed the word "pipeline" from the description of natural gas.

- Retained the following fuels: "wood residuals," "agricultural by-products," and "solid by-products", and added definitions of these terms to 40 CFR 98.6 (*see* section II.F of this preamble for further discussion).

- Added "Used oil" to the list of petroleum products, and added a definition to 40 CFR 98.6 (*see* section II.F of this preamble for further discussion).

- Removed "still gas" from the list of petroleum products and added "fuel gas."

- Corrected a typographic error in the HHV for ethane; changing it to 0.069 mmBtu/gal, rather than 0.096 mmBtu/gal.

- Revised footnote 1 regarding municipal waste combustor (MWC) units to make it clear that only MWC units that produce steam are prohibited from using the default HHV for MSW in Table C-1; MWC units that produce steam can still use the default CO₂ emission factor for MSW.

- Modified footnote 1 to Table C-1, to reflect the new biogenic CO₂ emissions calculation options for certain units that combust MSW and/or tires.

- Revised footnote 2 to clarify that if the conditions in 40 CFR 98.243(d)(2)(i) and (d)(2)(ii) and 40 CFR 98.252(a)(1) and (a)(2) do not apply, reporters subject to 40 CFR 98.243(d) of subpart X or subpart Y shall use either Tier 3 or Tier 4.

- Remove the qualifier of 100 percent for ethanol and biodiesel.

- Added a default CO₂ emission factor and a default high heat value for petroleum-derived ethanol. These are the same as the default values for biomass-derived ethanol.

Table C-2. We are finalizing the proposed amendments to remove the first iteration of Table C-2 and make minor corrections to the second one. The amendments consist of correcting the exponents (powers-of-ten) of several emission factors.

Standard conditions. A number of commenters requested that, for consistency with the rest of Part 98, we allow sources to use 60 °F as standard temperature instead of 68 °F, when Equation C-5 is used to calculate CO₂ mass emissions from the combustion of gaseous fuel. We proposed to allow this alternative for subparts X and Y, because the refining and petrochemical industries use 60 °F as standard temperature. We have concluded that the commenters' request to modify Equation C-5 accordingly is reasonable, and we are revising the definition of the term "MVC (molar volume conversion)" in the nomenclature of Equation C-5 (*see* revised 40 CFR 98.33(a)(3)(iii)). The revised definition of MVC allows sources to use a MVC value of either 849.5 standard cubic feet per kilogram mole (scf/kg mole) for a standard temperature of 68 °F, or 836.6 scf/kg mole for a standard temperature of 60 °F. A corresponding change has been made to the definition of "Standard conditions" in 40 CFR 98.6. For verification purposes, a data element has been added at 40 CFR 98.36(e)(2)(iv)(G), requiring sources using Equation C-5 to report which MVC value was used in the emissions calculations.

Miscellaneous revisions. We are amending 40 CFR 98.34(c) by adding the citations from 40 CFR part 75 that pertain to the initial certification of Tier 4 moisture monitoring systems. These amendments also correct an inadvertent omission in the verification section of subpart C, specifically, in 40 CFR 98.36(e)(2)(v)(C). That section requires units using the Tier 3 methodology to keep records of the method(s) used for carbon content determination. However, no mention is made of keeping records of the method(s) used to determine the molecular weight, which is a requirement for gaseous fuels. To correct this inadvertent oversight, we have amended 40 CFR 98.36(e)(2)(v)(C) to require records to be kept of the method(s) used for both carbon content and (if applicable) molecular weight determination. Finally, we have

corrected typographical errors in the definition of "CC" in the nomenclature of Equation C-5. This equation applies to gaseous fuels, not liquid fuels, and the units of measure for CC must be kg C per kg of fuel, rather than kg C per gallon.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

- A new equation has been added to Tier 1 to accommodate situations in which the fuel usage information on gas billing records is expressed in mmBtu. We have also added two new equations to 40 CFR 98.33(c) for calculating CH₄ and N₂O emissions when the fuel usage information on natural gas billing records is in units of therms or mmBtu.

- For units using the Tier 2 methodology that receive HHV data less frequently than monthly, or, for small units (< 100 mmBtu/hr) regardless of the HHV sampling frequency, we are allowing Equation C-2b to be used to calculate a fuel-weighted annual average HHV, instead of calculating the arithmetic average annual HHV.

- For consistency with other subparts, we have revised the nomenclature of Equation C-5, to allow reporters to use a molar volume conversion (MVC) constant referenced to a standard temperature of either 60 °F or 68 °F.

- For Tier 4 applications, we are allowing site-specific moisture default values to be based on fewer than nine Method 4 runs in cases where moisture data from the RATA of a CEMS are used to derive the default value and the applicable regulation allows a single moisture run to represent two or more RATA runs.

- We have modified the approach for calculating CO₂ mass emissions from an exhaust stream diverted from a CEMS monitored stack.

- For consistency with Subpart A, we have added language in several places stating that for Part 75 units, separate reporting of biogenic CO₂ emissions is optional in reporting year 2010 and mandatory thereafter.

- We have added a new paragraph, (e)(6), to 40 CFR 98.33, allowing Part 75 units to calculate biogenic CO₂ emissions using the same general approach that is used in 40 CFR 98.33(c)(4)(ii) for the CH₄ and N₂O emissions calculations.

- We have added an alternative calculation methodology, for biogenic

CO₂ emissions from the combustion of MSW and tires that may be used when the total contribution of these fuels to the unit's heat input is 10 percent or less. The methodology, which uses the Tier 1 equation together with default biogenic percentages, may also be used for small, batch incinerators that burn no more than 1,000 tons of MSW per year.

- We have removed the term "consecutive" between the words "24" and "hours", in reference to the minimum required sampling time for determining the percentage of biogenic CO₂ in flue gas when ASTM Method D7459-08 is used, thereby allowing samples to be collected for 24 total hours in a quarter, rather than 24 consecutive hours. We have also added a provision allowing sources to perform additional testing to demonstrate that sampling for 8 hours is sufficient.

- We have added language to 40 CFR 98.34(a)(2)(ii) and (b)(3)(ii)(B) explaining how to implement certain fuel oil sampling options, specifically, daily manual sampling and sampling after each addition of oil to the tank.

- To minimize unnecessary burden related to collecting information on small units aggregated in a group and for the common pipe configuration, we are removing and reserving 40 CFR 98.36 (c)(1)(ii), (c)(1)(iii), and (c)(3)(ii). We are no longer requiring sources to report the number of units in, or the cumulative heat input capacity of, an aggregated group of units or a group of units served by a common pipe. Only the maximum rated heat input capacity of the largest unit in the group must be reported.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Natural gas consumption expressed in therms.

Comment: Commenters were generally supportive of EPA's proposal to provide equations for cases where natural gas consumption is expressed in therms in billing records. One commenter noted that the proposed rule failed to take into account that on some natural gas billing records, the fuel usage is expressed in units of mmBtu. The commenter also brought to our attention that the proposed rule did not

provide corresponding equations for calculating CH₄ and N₂O emissions when the fuel usage information on gas billing records is expressed in therms.

Response: We agree with these comments and have made the following adjustments to the final rule text. First, a new equation, Equation C-1b, has been added to Tier 1 to accommodate situations in which the fuel usage information on gas billing records is expressed in mmBtu. Second, we have added two new equations to 40 CFR 98.33(c), *i.e.*, Equations C-8a and C-8b, for calculating CH₄ and N₂O emissions when the fuel usage information on natural gas billing records is in units of therms or mmBtu.

Site-specific stack gas moisture content values.

Comment: Commenters were generally supportive of the proposed rule changes related to determining the site-specific moisture default values. Two commenters requested that we allow the site-specific moisture default values to be based on fewer than nine Method 4 runs, in cases where moisture data from the RATA of a CEMS are used to derive the default value and the applicable regulation allows a single moisture run to represent two or more RATA runs.

Response: We believe that this is a reasonable request and have incorporated it into the final rule.

Determining emissions from an exhaust stream diverted from a CEMS monitored stack.

Comment: Commenters were supportive of the intent of the proposed amendments, but indicated that the proposed methodology for estimating the CO₂ mass emissions from the diverted gas stream would not be implementable at every affected facility. Specifically, commenters took issue with EPA's assumption that the CO₂ concentration in the diverted stream will be the same as the concentration in the main stack. According to the commenters, this is not the case, because dilution air introduced via auxiliary fans and other equipment will lower the CO₂ concentration of the side stream.

Response: We agree with the commenters' assessment and have modified the proposed approach for quantifying emissions in the diverted stream. The final rule requires annual emission testing of the diverted gas stream to be performed at a set point that best represents normal operation, using EPA Methods 2 and 3A and (if moisture correction is necessary) Method 4. A CO₂ mass emission rate is calculated from the test results. If, over time, flow rate of the diverted stream

varies little from the tested flow rate, then the annual CO₂ mass emissions for the diverted stream (which must be added to the CO₂ mass emissions measured at the main stack) will be determined simply by multiplying the CO₂ mass emission rate from the emission testing by the number of operating hours in which a portion of the flue gas was diverted from the main flue gas exhaust system. However, if the flow rate of the diverted stream varies significantly over the reporting year, the owner or operator must either perform additional stack testing or use the best available information (e.g., fan settings and damper positions) and engineering judgment to estimate the CO₂ mass emission rate at a minimum of two additional set points, to represent the variation across the normal operating range. Then, the most appropriate CO₂ mass emission rate must be applied to each hour in which a portion of flue gas is diverted from the main exhaust system. The procedures used to determine the annual CO₂ mass emissions for the diverted stream must be documented in the monitoring plan.

Fuel sampling for coal and fuel oil.

Comment: Commenters were generally supportive of the proposed amendments to 40 CFR 98.34(a)(2)(ii) and 40 CFR 98.34(b)(3)(ii) regarding the definition of “fuel lot.” However, we did receive requests to clarify the meaning of the terms “type of fuel” and “supply source,” pertaining to the proposal to require only one monthly sample to represent multiple fuel deliveries.

Response: The final rule clarifies that for coal, the type of fuel refers to the coal rank (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the type of fuel refers to the grade number or classification of the oil (*e.g.*, No. 2 oil, No. 6 oil, jet-A fuel, *etc.*). The term “supply source” is not so easily defined, however, and we have chosen not to include a definition to the final rule. Instead, you may use the following general guidelines. The term “supply source” can certainly refer to the coal mine, bulk terminal, or refinery from which the fuel is obtained. However, it also can apply to a fuel vendor who receives a particular type of fuel from different locations and distributes the fuel to his customers, provided the important properties of the fuel, such as its heating value, sulfur content, carbon content, *etc.*, are guaranteed to be within specified ranges.

Comment: With respect to the HHV sampling requirements for each fuel lot, commenters expressed concern that the option to sample fuel oil after each addition of fuel to the storage tank might not represent the fuel actually

being combusted. For instance, fuel may be added to an empty or a partly full tank that is out of service. Also, for a tank that is currently in service, due to infrequent combustion of fuel oil, it may have been months, or even years, since oil was last added to the tank, and it may be months or years before oil is added again.

Response: To address these concerns, the final rule requires at least one sample to be obtained from each storage tank that is currently in service, and an additional sample whenever fuel is added to the tank while it remains in service. If multiple additions are made to an in-service tank on a given day (*e.g.*, from multiple deliveries) one sample taken after the final addition is sufficient. No sampling is required for addition of fuel to a tank that is out of service. Rather, a sample must be taken when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service.

Tier 4 monitoring threshold for units that combust MSW.

Comment: Commenters were generally supportive of the proposed amendment to increase the Tier 4 monitoring threshold for combustion of municipal solid waste from 250 to 600 tons per day. One concern was that the amendment might not be finalized before the end of 2010; therefore, they asked for the final rule to provide a six month extension of the January 1, 2011 regulatory deadline for installing and certifying CEMS. Some commenters were concerned that this proposed change would affect the quantity of emissions reported under the program and were, therefore, concerned about finalizing this proposed amendment.

Response: There is no need for the requested extension because units at or above the 600 ton per day threshold have been on notice since the 2009 final rule that they are required to use CEMS. The proposed revision to the Tier 4 monitoring threshold should not have caused them to think otherwise. For units in-between the original threshold of 250 tons per day and the revised threshold of 600 tons per day, an extension is unnecessary because these units can use Tier 2 for the 2010 reporting year. We disagree with concerns that the final amendments will impact the quantity of data reported to the program, because the final amendments still require the same units to report GHG emissions. The only difference is that they may be using the Tier 2 methodology instead of Tier 4.

Biogenic CO₂ emissions from biomass combustion.

Comment: Regarding the proposed revisions to the optional biogenic CO₂ emissions calculation methodology for units with CEMS described in 40 CFR 98.33(e)(2), one commenter recommended that we make the methodology more flexible by modifying Equation C–13. The change to this equation proposed by the commenter would allow the volume of CO₂ from combustion of the biomass fuel (rather than the fossil fuel) to be calculated directly and then used in Equation C–14 to calculate the biogenic percentage of the annual CO₂ mass emissions.

Response: EPA has not incorporated the commenter's proposed changes. Although the proposed modification to the methodology could work for fuels such as wood residue and bark (which have F-factors listed in Table 1 in section 3.3.5 of 40 CFR part 75, appendix F), the commenter appears to be unaware that we proposed to remove from 40 CFR 98.33(e)(1) the restriction prohibiting units with CEMS from using the Tier 1 methodology to calculate biogenic CO₂ emissions. As stated above, we are finalizing that amendment as proposed. Therefore, since both Tier 1 and the commenter's suggested methodology require sources to quantify the amount of biomass fuel combusted, and since the Tier 1 methodology is significantly simpler than the commenter's proposal, there is no need to revise the calculation procedures in 40 CFR 98.33(e)(2).

Comment: Many units and industrial processes burn relatively small amounts of partly biogenic fuels such as tires and MSW, as supplementary fuels. Quarterly sampling and analysis of the flue gas using ASTM Methods D7459–08 and D6866–08 is the only available methodology in Part 98 for quantifying biogenic CO₂ emissions from these fuels. Some commenters requested relief from reporting biogenic CO₂ emissions from such fuels when they account for less than 10 percent of a unit's heat input. Another commenter asked EPA to either make reporting of biogenic CO₂ optional or reduce the amount of required testing with the ASTM methods to once every five years, for small batch incinerators that combust MSW. The commenter provided data for a typical batch incinerator, showing that in 2009, less than 400 metric tons of biogenic CO₂ were emitted from the unit.

Response: We do not intend to grant a reporting exemption for MSW combustion, and, for tires, although the reporting is optional at present, we intend to revisit this issue in the future. However, we are persuaded that the cost

of performing the ASTM methods (roughly \$5,000 to \$10,000 each quarter) is unreasonably high for sources that burn very small amounts of MSW and/or tires and emit comparatively little biogenic CO₂. Also, for sources that combust tires and wish to report biogenic CO₂, the ASTM methods are their only option. In view of these considerations, we have added an alternative calculation methodology for biogenic CO₂ emissions from the combustion of tires and/or MSW. The methodology is found at 40 CFR 98.33(e)(3)(iv), and may be used when the total contribution of these fuels to the unit's heat input is 10 percent or less. We are also allowing this methodology to be used for small batch incinerators that burn no more than 1,000 tons of MSW per year. Supplementary information provided by the commenter who requested reduced testing of these incinerators indicates that the rated capacities of the units can be as high as 1,300 lb/hr of MSW, but that in practice, since the units operate in batch mode, a more realistic estimate of the actual, annualized capacity of the units is somewhere between 100 and 200 lb/hr (see EPA-HQ-OAR-2008-0508). If one of these incinerators were to combust as much as 200 lb/hr of MSW on an annualized basis, this would equate to approximately 875 tons of MSW per year. The total annual CO₂ emissions from the combustion of 875 tons of MSW is estimated to be about 800 metric tons, based on the default emission factors in Table C-1. Assuming a biogenic fraction of 0.60 for MSW, the biogenic portion of the total annual CO₂ emissions would be 480 metric tons, which is less than 2 percent of the 25,000 metric ton applicability threshold in 40 CFR 98.2 for Part 98 facilities. Based on the above analysis, we have concluded that it is appropriate to allow Tier 1 to be used together with a default biogenic percentage of 0.60 to estimate the biogenic CO₂ emissions from MSW combustion in small batch incinerators, in lieu of using ASTM Methods D7459-08 and D6866-08. To allow for some possible variation in the annualized capacity of these units, the final rule extends the use of the alternative calculation methodology to batch incinerators that combust no more than 1,000 tons of MSW per year (which corresponds to about 540 tons of biogenic CO₂ per year).

Comment: With regard to the use of ASTM Methods D7459-08 and D6866-08, two commenters from facilities that combust refuse-derived fuel (RDF) asked us to consider shortening the sampling time to 8 hours, in cases where the fuel

is relatively homogeneous. Both commenters submitted data comparing the results of 8-hour samples against the results of 24-hour samples. For one source, the 8-hour sample results were within 3.3 percent of the 24-hour results, and for the other source the results were within 1.7 percent.

Response: EPA agrees that under certain circumstances, it may be appropriate to shorten the sampling time. Therefore, we are adding an option to 40 CFR 98.34(d) and (e), allowing sources to demonstrate that 8 hours of sampling per quarter is sufficient. The demonstration requires a minimum of two 8-hour tests and one 24-hour test, performed under normal, stable operating conditions. The demonstration tests must be distinct, *i.e.*, no overlapping of the 8-hour and 24-hour test periods is permitted. If the average biogenic fraction obtained from the 8-hour tests is within ± 5 percent of the results from the 24-hour test, then, in subsequent quarters, the Method D7459-08 sampling time may be reduced to 8 hours. The results of the demonstration must be documented in the monitoring plan. Note that although the data provided by the commenters showed that the 8-hour and 24-hour sample results differed by no more than 3.3 percent, we believe that ± 5 percent is a more reasonable acceptance criterion. This is because the methodology will likely be used for the combustion of tires as well as MSW. Tire-derived fuel (TDF) has a much lower biogenic fraction than MSW (typically about 0.20, compared to 0.60 for MSW). An acceptance criterion lower than 5 percent for TDF combustion would require the difference between the 8-hour and 24-hour sample results to be less than 0.01, and would be overly stringent.

Use of consensus standard methods.

Comment: We received both supportive and adverse comments on the proposed amendments to remove reference to specific consensus standards. Commenters that objected to the proposal stated that elimination of the lists of acceptable methods and allowing the use of "industry standard practice" weakens the rule. According to these commenters, there is no way to evaluate the technical merits of an "industry standard practice," and the quality of the reported GHG emissions data could suffer as a result.

Response: We do not agree with the objections raised by these commenters. Subpart C covers a large range of industries, perhaps including some that we are not even aware of yet that are significant emitters of GHG emissions and therefore covered by the rule. In

these early years of the program, we want to ensure that the methods required by the rule are appropriate for all facilities subject to subpart C of the rule. Although we attempted to assemble a comprehensive list of methods and provide appropriate alternatives in the 2009 final rule, based on questions received we determined that it was likely that other valid methods from these organizations and practices were overlooked. For instance, under the 2009 final rule, even updates to the IBR methods to reflect the latest practices would not have been acceptable without a rulemaking. The commenters did not sufficiently justify why opening up to industry consensus standards would compromise data quality. In fact, the opposite could be said where more updated versions of previously incorporated standards are now allowable.

Further, subpart C already includes a mechanism by which we can evaluate the methods being used by industry. Sections 98.36(e)(2)(iii) and 98.36(e)(2)(v) require that records be kept of the methods that are used for flow meter calibration and for HHV and carbon content determinations, and 40 CFR 98.36(e)(4) requires sources to provide this information to EPA within 30 days of receiving a request for it.

We note that we have not opened all subparts more broadly to industry consensus standards. Please see the responses to comments in Section II.K (Hydrogen Production) and Section II.M (Petrochemical Production) of this preamble for our response to similar comments under these subparts.

Electronic data reporting and recordkeeping.

Comment: Two commenters asked us to either remove or modify the proposed requirement to report the number of units in an aggregated group of units. One commenter suggested that reporting would be simplified if very small sources such as water heaters, space heaters, lab burners, *etc.*, were lumped together and counted as one unit. The other commenter stated that it is burdensome to keep an accurate count of these small domestic units at large, complex industrial facilities. That same commenter also suggested that only units with heat input ratings of 10 mmBtu or greater should be included in the count. A third commenter noted that it is also difficult to report the cumulative maximum heat input rating of a group of units, as required under 40 CFR 98.36(c)(1)(iii), when numerous small domestic units, some of which may not have a heat input rating, are included in an aggregated group.

Response: We believe these comments have merit. After careful consideration, we have concluded that for verification purposes, we do not need to know either the exact number of units in an aggregated group or the combined maximum rated heat input of the group. The only critical data element is the maximum rated heat input capacity of the largest unit in the group. This information is needed to confirm that none of the units exceeds 250 mmBtu/hr, which is the condition that must be met to use the unit aggregation option in 40 CFR 98.36(c)(1). Therefore, in the final rule, we are withdrawing the proposed requirement to report the number of units in an aggregated group of units, and are removing the requirement to report the combined maximum rated heat input of the group. We also are withdrawing the proposed requirement under 40 CFR 98.36(c)(3)(ii) to report the number of units served by a common fuel pipe. The issue is the same for the common pipe configuration as for the aggregated group of units, *i.e.*, hundreds of small, domestic units may be served by the common pipe. To effect these rule changes, 40 CFR 98.36(c)(1)(ii), (c)(1)(iii), and (c)(3)(ii) have been removed and reserved.

Table C-1.

Comment: Two commenters questioned the appropriateness of listing MSW with plastics and petroleum coke. Further, they noted that petroleum coke is listed twice in the table, first under petroleum products and then again under “other fuels (solid).” According to the commenters, petroleum coke is a petroleum derivative, and is more appropriately listed with the other “petroleum products.”

Response: The category “other fuels (solid)” in Table C-1 is not intended to make any policy statement about the nature of the fuels included in the category. The fuels included in “other fuels (solid)” are miscellaneous fuels that do not fit into any other existing category for the purposes of this rule. Petroleum coke was included as a petroleum product in the 2009 final rule (74 FR 56409). However, the HHV units of measure for petroleum products listed in Table C-1 are in mmBtu per gallon and some reporters were confused about how to appropriately calculate CO₂ emissions from petroleum coke, since it is actually a solid fuel, and is nominally measured in units of short tons. By listing petroleum coke as a solid fuel with a heating value in units of mmBtu/short ton, EPA intends to alleviate confusion about how emissions are to be calculated for petroleum coke.

However, we also understand that some facilities report petroleum coke usage to the Energy Information Administration (EIA) in units of equivalent barrels of petroleum, and may prefer to report petroleum coke consumption in units of gallons under this rule. As such, EPA is not proposing to remove petroleum coke from the list of petroleum products in Table C-1. The two HHVs for petroleum coke differ only in units of measure. They will give equivalent results when CO₂ mass emissions are calculated.

Comment: Two commenters asserted that plastics are a small component of MSW and there is no reason why plastics should be listed as a separate fuel in Table C-1. These commenters stated that to the best of their knowledge, plastics are not combusted as a separate fuel stream, and they recommended that EPA delete plastics from Table C-1.

Two other commenters, however, stated that plastics are, in fact, sometimes separated out from MSW as a separate stream. These commenters provided a suggested definition of “plastics” and requested that we add it to 40 CFR 98.6. The commenters also asked us to modify the definition of MSW, to specifically exclude plastics that are recovered from MSW, processed separately, and disposed.

Response: As mentioned in the preamble to the August 11, 2010 proposed rule (75 FR 48764), facilities have questioned EPA as to why plastics and waste oil, two fuels that appeared in Table C-2 of the April 10, 2009 proposed rule, were left out of the October 30, 2009 final rule. Responding to these concerns, on August 11, 2010 we proposed to add both fuels to Table C-1. Today’s rule retains these entries, except that waste oil has been redesignated as “used oil.” In view of the input received from the commenters who brought to our attention that plastics (including such things as “* * * bottles, containers, bags, CD cases, sheeting, packaging, broken consumer goods, etc. * * *”) are sometimes recovered from MSW and processed separately, we decided not to incorporate the recommendation of the other commenters who asked us to delete plastics from the table.

We see no need to add a definition of plastics to 40 CFR 98.6, since plastic materials are readily identifiable. However, to address the commenters’ chief concern, we have modified the definition of MSW to clearly state that insofar as plastics (along with certain other materials) are separated out from MSW, processed and disposed of, they are not considered to be “municipal solid waste.”

Comment: Two commenters argued against the inclusion of default factors for “fuel gas” in Table C-1. They argued that this would have a negative impact on chemical plant fuel gas streams that were previously exempt from Tier 3 requirements when the streams provide less than 10 percent of the annual heat input to a unit rated greater than 250 mmBtu/hr) because Table C-1 previously had no factors for fuel gas. According to the commenters, the proposed inclusion of default factors for “fuel gas” in Table C-1 requires monitoring and reporting of GHG emissions from these gas streams. Both commenters suggested that Table C-1 should include default factors for “refinery fuel gas” rather than “fuel gas.” One commenter also suggested revising the definition of “fuel” and Footnote 2 associated with the default values for fuel gas in Table C-1 to clarify that fuel gas is specific to refineries and petrochemical plants, but excludes process off-gases from chemical production plants.

Response: Default values for fuel gas in Table C-1 are necessary to allow refineries and petrochemical plants to use Tier 1 or Tier 2 methods for certain small fuel gas streams that were proposed to be excluded from the requirement to use Tier 3 for fuel gas in subparts X and Y. In providing these factors, we did not intend to require chemical plants to monitor and report GHG emissions generated by the combustion of “fuel gas” that were excluded from reporting requirements in the October 30, 2009, final Part 98. Therefore, we agree that some additional clarification of terms is needed to prevent the fuel gas factor from requiring measurement and reporting of GHG from the chemical plant vent gases.

While changing the term used in Table C-1 to “refinery fuel gas” may have helped to clarify the intent, we do not believe, given the definition of “fuel gas” in the final rule, that this would adequately address the issue. “Fuel gas” as defined in the October 30, 2009, final Part 98 means “gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.” The inclusion of the phrase “or similar industrial process unit” within the definition of fuel gas expanded the meaning of fuel gas beyond refineries and petrochemical plants. Without specifically defining the term “refinery fuel gas” we expect that the rule language would have remained ambiguous, especially since refinery

fuel gas was still intended to apply to some petrochemical processes.

To clarify our original intent of the proposed inclusion of default factors for fuel gas in Table C–1, we are revising the definition of “fuel gas” to delete reference to other similar industrial process units. In Part 98, the term “fuel gas” is intended to apply to petroleum refineries and petrochemical plants, so this revision does not affect other Part 98 requirements; it simply clarifies that “fuel gas” and the fuel gas factors are specific to petroleum refineries and petrochemical plants.

The commenter suggested revising the definition of fuel to mean “solid, liquid or gaseous combustible material, but excludes process waste off gases from chemical production plants that are not petroleum refineries or petrochemical plants.” We have determined that this change is not necessary because we have addressed the commenter’s concerns through the change in the definition of fuel gas. We are amending Footnote 2 of Table C–1, as requested, to clarify further that only reporters subject to 40 CFR 98.243(d) of subpart X or subpart Y are required to use Tier 3 or Tier 4 methodologies when the specific conditions outlined in the footnote do not exist.

H. Subpart D—Electricity Generation

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending 40 CFR 98.40(a) by adding the word “mass” between the words “CO₂” and “emissions” to make it clear that subpart D applies only to units in two categories: ARP units and non-ARP electricity generating units (EGUs) that are required to report CO₂ mass emissions data to EPA year-round.

Optional reporting of biogenic CO₂. For consistency with the amendments to subpart C, we have revised 40 CFR 98.43 to clarify that for subpart D units, reporting of biogenic CO₂ emissions is optional only for the 2010 reporting year, and mandatory thereafter. We are also adding a new paragraph 40 CFR 98.43(b) indicating that biogenic CO₂ emissions must be calculated and reported by following the applicable methods specified in 40 CFR 98.33(e). Fossil CO₂ emissions are calculated by subtracting the biogenic CO₂ mass emissions calculated according to 40 CFR 98.33(e) from the cumulative annual CO₂ mass emissions from paragraph (a)(1) of this section.

Data reporting requirements. Section 98.46 of subpart D specified that the owner or operator of a subpart D unit must comply with the data reporting requirements of 40 CFR 98.36(b) and, if

applicable, 40 CFR 98.36(c)(2) or (c)(3). These section citations were incorrect. Subpart D units all use the CO₂ mass emissions calculation methodologies in 40 CFR part 75. Therefore, the applicable data reporting section for these units is 40 CFR 98.36(d), not 40 CFR 98.36(b), 40 CFR 98.36(c)(2), or 40 CFR 98.36(c)(3). We are amending 40 CFR 98.46 to correct this error.

Recordkeeping. We are amending 40 CFR 98.47 to state that the records kept under 40 CFR 75.57(h) for missing data events satisfy the recordkeeping requirements of 40 CFR 98.3(g)(4) for those same events. We have concluded that, as a practical matter, the missing data records required to be kept under 40 CFR 75.57(h) are substantially equivalent to the records required under 40 CFR 98.3(g)(4).

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA–HQ–OAR–2008–0508).

- Making separate reporting of biogenic emissions optional for part 75 units in the 2010 reporting year and mandatory every year thereafter. See sections II.C and II.G of this preamble.
- Adding a provision to subpart D to clarify how to calculate and report biogenic CO₂ emissions, referencing the applicable methods in 40 CFR 98.33(e) and the reporting requirements in 40 CFR 98.3(c)(4) and (c)(12).

2. Summary of Comments and Responses

No significant comments were received on the specific technical amendments to subpart D. Comments related to the proposed separate reporting of biogenic emissions for units subject to 40 CFR part 75 can be found in Sections II.C and II.G of this preamble.

I. Subpart F—Aluminum Production

1. Summary of Final Amendments and Major Changes Since Proposal

Throughout subpart F we are making corrections as needed for typographical errors and alphanumeric sequencing. We are amending 40 CFR 98.63 to clarify that each perfluorocarbon (PFC) compound (perfluoromethane, CF₄, also called tetrafluoromethane, and perfluoroethane, C₂F₆, also called hexafluoroethane) must be quantified and reported and to clarify in 40 CFR 98.63(c) that reporters must use CEMS if the process CO₂ emissions from anode

consumption during electrolysis or anode baking of prebake cells are vented through the same stack as a combustion unit required to use CEMS. This requirement existed in the final rule, however, the cross-reference was omitted from the introductory language of 40 CFR 98.63(c).

We are amending 40 CFR 98.64 to clarify the type of parameters that must be measured in accordance with the recommendations of the EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminum Production (2008), and the frequency of monitoring for those parameters that are not measured annually, but are instead measured on a more or less frequent basis. We are also inserting dates into this paragraph. In inserting these dates, we have decided to use dates in reference to the effective date of the 2009 final rule, as opposed to the publication date as was written in the final rule. It was determined to be more appropriate to use the effective date of the rule as the basis for the timing of the requirements. Therefore, we are amending the paragraph to read “December 31, 2010” in place of “one year after publication of the rule” and are inserting “December 31, 2012” in place of “three years after publication of the rule.”

We are amending Table F–2 to clarify that default CO₂ emissions from pitch volatiles combustion are relevant only for center work pre-bake (CWPB) and side work pre-bake (SWPB) technologies.

We are also amending Table F–1 to spell out the acronyms for the technologies covered by that table; *i.e.*, CWPB, SWPB, vertical stud Söderberg (VSS), and horizontal stud Söderberg (HSS).

The comments received supported the proposed amendments, so the amendments to subpart F are finalized as proposed.

2. Summary of Comments and Responses

One comment letter was received on this subpart, and it supported the proposed amendments. The summary and response to this comment letter can be found in the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA–HQ–OAR–2008–0508).

J. Subpart G—Ammonia Manufacturing

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending subpart G to remove reporting of the waste recycle stream or

purge, and to make subpart G conform to the amendments to the calibration requirements in subpart A. With respect to the waste recycle stream, we are eliminating the calculation, monitoring and reporting of the emissions associated with the waste recycle stream or purge currently required by Equation G-6 from 40 CFR 98.73, 98.74, 98.75, and 98.76. Carbon dioxide emissions from waste recycle stream or purge gas used as fuel will still be accounted for accurately using Equation G-5 in subpart G. Because total process emissions, calculated using Equation G-5, will also account for emissions associated with use of the purge gas as a fuel, we are amending 40 CFR 98.72(b) so that subpart C does not apply to CO₂ emissions resulting from the use of purge gas as a fuel.

We are clarifying in 40 CFR 98.72(a) and in the definition of CO₂ in Equation G-5 that CO₂ process emissions reported under this subpart may include CO₂ that is later consumed on site for urea production and therefore is not released to the ambient air from the ammonia manufacturing process unit. We have included this clarification because although the equations accurately reflect total CO₂ that is generated from the ammonia manufacturing process, not all of that CO₂ is released on site. Rather, some of the CO₂ may be used for urea production and not be actually released to the atmosphere until use of the urea at an off-site location.

We are amending 40 CFR 98.74(d) to limit the flow meter calibration accuracy requirements of 40 CFR 98.3(i)(2) and (i)(3) to only meters that are used to measure liquid and gaseous feedstock volumes. In accordance with 40 CFR 98.3(i)(1), each measurement device that is not used to measure liquid and gaseous feedstock volumes, but is used to provide data for the GHG emissions calculations, will have to be calibrated to an accuracy within the appropriate error range for the specific measurement technology, based on an applicable operating standard, such as the manufacturer's specifications.

We are amending the definition of CO₂ emissions in Equation G-5 to indicate that the CO₂ emissions estimates under subpart G may include CO₂ that is later consumed on site for urea production and therefore not released to the atmosphere from the ammonia manufacturing process unit. This change does not affect the total CO₂ emissions that are quantified and reported to EPA under the calculation equations in 40 CFR 98.73. Likewise, we are amending 40 CFR 98.76(b) to require reporting of the CO₂ from the ammonia

manufacturing process unit that is then used to produce urea and the method used to determine that quantity of CO₂ consumed.

In addition, we are amending subpart G to correct several typographical errors and an incorrect cross-reference to another subpart in 40 CFR part 98. We are correcting the terms and definitions for annual CO₂ emissions arising from gaseous, liquid, and solid fuel feedstock consumption in Equations G-1, G-2, and G-3, respectively, in 40 CFR 98.73. We are correcting 40 CFR 98.76(a) by changing the cross-reference from “§ 98.37(e)(2)(vi)” to “§ 98.37.”

We are amending the data reporting requirements in 40 CFR 98.76(b)(6) and (15) for consistency with the calculation procedures in 40 CFR 98.73(b)(6). We are amending 40 CFR 98.76(b)(6) to change “petroleum coke” to “feedstock” because petroleum coke is the incorrect term, and amending 40 CFR 98.76(b)(15) to specify that the carbon content analysis method being reported is for each month. We are also removing 40 CFR 98.76(b)(17) for the reporting of urea produced, if known, as well as reporting requirements in 40 CFR 98.76(c) for total pounds of synthetic fertilizer produced and total nitrogen contained in that fertilizer.

No major changes have been made to the amendatory language since proposal.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA-HQ-OAR-2008-0508).

Comment: One commenter was supportive of all proposed amendments to subpart G. However, we received adverse comments on the proposed amendment to remove requirements to report the total quantity of synthetic fertilizer produced and the nitrogen content of fertilizer. The commenter asserted that EPA does not offer a reason for the deletion of fertilizer reporting requirements, and noted that synthetic fertilizer application drives a large fraction of N₂O emissions from agricultural soils. They asserted that the reporting requirements should be retained for several reasons, including that collecting information for N₂O emissions, even if it is from less than one-half of the total fertilizer produced, is valuable. Further, the commenter

contended that justifying removal of the reporting requirement because of the availability of other data through the Association of American Plant Food Control Officials is not appropriate because those other data may not be available reliably into the future and do not map emissions back to specific facilities. They argued that reporting of synthetic fertilizer production is a good first step in estimating N₂O emissions from agricultural soils.

Another commenter countered many of the points raised above, asserting that data on domestic synthetic fertilizer production is not a good indicator of N₂O emissions from farming because the rule did not capture all fertilizer production and not all fertilizer is applied to fields.

Response: EPA has finalized, as proposed, the amendment to remove reporting requirements of the total amount of synthetic fertilizer produced and nitrogen contained in that fertilizer. EPA has concluded that the burden placed on fertilizer production facilities to report on total pounds of synthetic fertilizer and total nitrogen contained in that fertilizer would not be commensurate with the value of the data we would receive in terms of improving our ability to estimate N₂O emissions from soils. Specifically, facility specific data from producers on the nitrogen content of synthetic fertilizer is of minimal value in estimating soil N₂O emissions by itself. As explained in the proposal preamble (75 FR 48767), there are a variety of inputs that would be valuable to consider to estimate N₂O emissions from agricultural soils, including fertilizer application rates, timing of application, and the use of slow release fertilizers and nitrification/release inhibitors, none of which would be provided through the provision removed from the rule. Given that the information required from the final rule would not provide sufficient information to estimate N₂O emissions from fertilizer application to soils, we are removing the reporting requirement at this time. While there is concern over the potential future loss of the Association of American Plant Food Control Officials data, EPA has determined that it is preferable to remove the incomplete reporting requirement at this time and, if appropriate in the future, reconsider in a comprehensive manner reporting of information on fertilizer production, import and use practices.

K. Subpart P—Hydrogen Production

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending the definition of the terms for the average carbon content (CC_n) and molecular weight (MW_n) in Equation P–1 of 40 CFR 98.163 to clarify that, where measurements are taken more frequently than monthly, CC_n and MW_n should be calculated using the arithmetic average of measurement values within the month.

We are amending 40 CFR 98.164(b)(1) so it is consistent with today's amendments to 40 CFR 98.3(i). First, we are limiting the flow meter calibration accuracy requirements of 40 CFR 98.3(i)(2) and (i)(3) to meters that are used to measure liquid and gaseous feedstock volumes. In accordance with 40 CFR 98.3(i)(1), all other measurement devices that are used to provide data for the GHG emissions calculations have to be calibrated only to an accuracy within the appropriate error range for the specific measurement technology, based on an applicable operating standard, such as the manufacturer's specifications. Second, we are removing the requirements for solids weighing equipment and oil tank drop measurements to be calibrated according to 40 CFR 98.3(i), because the provisions of 40 CFR 98.3(i) apply only to gas and liquid flow meters. For oil tank drop measurements, the QA requirements of 40 CFR 98.34(b)(2) apply.

As a harmonizing amendment with the amendment allowing the use of a gas chromatograph (described in 40 CFR 98.164(b)(5)), we are adding the phrase "no less frequent" to 40 CFR 98.164(b)(2). This change indicates that when determining the carbon content and the molecular weight of "other gaseous fuels and feedstocks" (e.g., biogas, refinery gas, or process gas), you must undertake sampling and analysis no less frequently than weekly. Replacing a "weekly" requirement with "no less frequent than weekly" allows for the use of continuous, on-line equipment gas chromatographs.

We are amending 40 CFR 98.164(b)(5) to allow the use of chromatographic analysis of the fuel, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting

of Greenhouse Gases Rule" (see EPA–HQ–OAR–2008–0508).

- Modification of Equation P–1 to account for measurements taken more frequently than monthly to determine the molecular weight of the gaseous fuel and feedstock.

- Inclusion of the option to use a gas chromatograph (both continuous and non-continuous) for determining the carbon content and molecular weight of gaseous fuels.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA–HQ–OAR–2008–0508).

Comment: One commenter noted that the fuels and feedstocks to a hydrogen plant subject to subpart P requirements are often the same fuels that are burned in combustion units subject to subpart C requirements. The commenter further noted that both subparts had different monitoring and QA/QC requirements which would pose a problem for a facility trying to determine which method to use.

Response: No change has been made as a result of this comment. We did not receive sufficient information from the commenter as to why they would not be able to comply using the methods already prescribed in subpart P for determining carbon content and molecular weight. As noted by the commenter, facilities only subject to subpart C must use a method published by a consensus standards organization if such a method exists, or an industry consensus standard practice. Therefore, the methods in the 2009 final rule for subpart P could be used to meet the requirements in subpart C. We determined that it was appropriate to open the methods to industry consensus standards or industry standard practices for facilities subject to subpart C only, because the industries covered by subpart C could be wide ranging and the specific methods listed may not be appropriate for certain industry types. Because the commenter does not provide specific concerns as to why the methods listed in subpart P are not appropriate, we have decided not to remove the applicable methods listed in subpart P and replace them with the option to use consensus based standards or industry consensus standards.

Comment: One commenter requested that EPA allow the use of gas chromatographs as an alternative method for determining the carbon content in gaseous fuels and feedstocks.

Response: EPA acknowledges the commenter's recommendation to include the option to use gas chromatographs for measuring the carbon content and molecular weight of fuels and feedstocks in subpart P. As a result, EPA has revised the monitoring and QA/QC requirements to allow the use of gas chromatographs, both continuous and non-continuous, to determine the carbon content and molecular weight of fuels and feedstocks provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

L. Subpart V—Nitric Acid Production

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending 40 CFR 98.226 to remove the synthetic fertilizer and total nitrogen reporting requirement in 40 CFR 98.226(o). The detailed rationale for this amendment is provided in Section II.J of this preamble.

2. Summary of Comments and Responses

Several comments were received on the proposal to remove the synthetic fertilizer and total nitrogen reporting requirement in 40 CFR 98.226(o). Please see section II.J (Ammonia Production) of this preamble for the comments and responses related to reporting of fertilizer production data.

M. Subpart X—Petrochemical Production

1. Summary of Final Amendments and Major Changes Since Proposal

Numerous issues have been raised by owners and operators in relation to the requirements in subpart X for petrochemical production facilities. The issues being addressed by the amendments include the following:

- Distillation and recycling of waste solvent.
- Process vent emissions monitored by CEMS.
- Process off-gas combustion in flares.
- CH_4 and N_2O emissions from combustion of process off-gas.
- Molar volume conversion (MVC) factors.
- Methodology for small ethylene off-gas streams.
- Monitoring and QA/QC requirements.
- Reporting requirements under the CEMS compliance option.

- Reporting requirements for the ethylene-specific option.
- Reporting measurement device calibrations.

- For the mass balance option, sampling frequency when receiving multiple deliveries from same supply source.

Distillation and recycling of waste solvent. We are adding a new paragraph, as proposed, to 40 CFR 98.240(g) to specify that a process that distills or recycles waste solvent that contains a petrochemical is not part of the petrochemical production source category.

Process vent emissions monitored by CEMS. We are adding a sentence, as proposed, to 40 CFR 98.242(a)(1) that specifies CO₂ emissions from process vents routed to stacks that are not associated with stationary combustion units must be reported under subpart X when you comply with the CEMS option in 40 CFR 98.243(b).

Process off-gas combustion in flares. We are amending 40 CFR 98.242(b), as proposed, by removing the reference to flares.

CH₄ and N₂O emissions from combustion of process off-gas. We are amending 40 CFR 98.243(b), as proposed, to clarify that either the default HHV for fuel gas or a site-specific calculated HHV may be used when using Tier 3 procedures to calculate CH₄ and N₂O emissions from combustion units that burn petrochemical process off-gas and are monitored with a CO₂ CEMS.

Sampling frequency for mass balance method. We are amending 40 CFR 98.243(c)(3) to clarify that when multiple deliveries of a particular liquid or solid feedstock are received from the same supply source in a month, one representative sample is sufficient for the month. The amendment is being made in response to a comment received. As explained in section II.M.2 of this preamble, we are amending 40 CFR 98.243(c)(3) to make the language in subpart X consistent with a similar amendment for fuel sampling in 40 CFR 98.34(b)(3)(ii)(B). The new language does not change the requirements in 40 CFR 98.243(c).

Molar volume conversion (MVC) factors. We are amending Equation X-1, as proposed, to provide two alternative values of MVC that correspond to the two most common standard conditions output by the flow monitors. Additionally, the reporting requirements related to this equation are being amended, as proposed, to include reporting of the standard temperature at which the gaseous feedstock and product volumes were determined

(either 60 °F or 68 °F) and to afford verification of the reported emissions.

Methodology for small ethylene off-gas streams. We are finalizing amendments to 40 CFR 98.243(d), as proposed, to allow the use of Tier 1 or Tier 2 methods for small flows (in cases where a flow meter is not already installed). Specifically, Tier 1 or Tier 2 methods may be used for ethylene process off-gas streams that meet either of the following conditions:

- The annual average flow rate of fuel gas (that contains ethylene process off-gas) in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute (scfm) at 60 °F and 14.7 pounds per square inch absolute (psia) and a flow meter is not installed at any point in the line supplying fuel gas or at an upstream common pipe.

- The combustion unit has a maximum rated heat input capacity of less than 30 mm Btu/hr, and a flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe.

As in the proposal, this amendment also specifies how to calculate the annual average flow rate under the first condition. Specifically, the total flow obtained from company records is to be evenly distributed over 525,600 minutes per year. In response to comments we are making an editorial change to the introductory paragraph of 40 CFR 98.243(d) to clarify that the common pipe reporting alternative may be used when applicable; the intent of the requirements in this section are not changed by this editorial change. We are also making a number of other editorial changes to 40 CFR 98.243(d), as proposed, to integrate the amended option with the existing requirements. Finally, we are amending 40 CFR 98.246(d)(2) and 98.247(c), as proposed, to add reporting and recordkeeping requirements that are related to the amendments in 40 CFR 98.243(d)(2).

Monitoring methods for determining carbon content and composition. We are finalizing the proposed addition of ASTM D2593-93 (Reapproved 2009), Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, to 40 CFR 98.244(b)(4). We are further amending 40 CFR 98.244(b)(4), as proposed, by adding a new paragraph that will allow the use of industry standard practice to determine the carbon content or composition of carbon black feedstock oils and carbon black products.

We also added two more published methods to the list in 40 CFR

98.244(b)(4) of the final rule: ASTM D7633, Standard Test Method for Carbon Black—Carbon Content, and EPA Method 9060A in EPA publication SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods. We also added an option, already proposed in subparts C and Y, to use results of chromatographic analysis of feedstocks and products, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions. Finally, we added an option to use results of a mass spectrometer analysis of a feedstock or product, provided that the mass spectrometer is operated, maintained, and calibrated according to the manufacturer's instructions.

We are also amending 40 CFR 98.244(b)(4), as proposed, to provide facilities the option to determine carbon content or composition of feedstocks or products using modified versions of the analytical methods listed in 40 CFR 98.244(b)(4) if the listed methods are not appropriate for reasons noted below. The proposed amendments in this section would have allowed the use of "other analytical methods" if methods listed in 40 CFR 98.244(b)(4) are not appropriate for any of the same reasons. However, in response to comments, we revised this provision to allow the use of "other methods" rather than "other analytical methods" so that non-analytical methods also can be used. The conditions under which the listed methods may be considered inappropriate are the same as at proposal. Specifically, a listed method may be considered inappropriate if the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method will be unsafe.

We are amending the reporting requirements in 40 CFR 98.246(a)(11), as proposed, so that if an alternative method is used, facilities must include in the annual report the name or title of the method used and, the first time it is used, a copy of the method and an explanation of why the use of the alternative method is necessary. Also as proposed, the amendments to 40 CFR 98.244(b)(4) may be used for the 2010 reporting year.

QA/QC requirements. To maintain consistency with the amendments to 40 CFR 98.3(i), we are amending, as proposed, the QA/QC provisions for weighing devices, flow meters, and tank level measurement devices in 40 CFR 98.244 (b)(1), (b)(2), and (b)(3).

Reporting requirements under the CEMS compliance option. As proposed, we are making a number of changes in

40 CFR 98.246(b)(1) through (b)(5) to clarify the reporting requirements under the CEMS compliance option.

First, we are moving the requirement for reporting of the petrochemical process ID from 40 CFR 98.246(b)(3) to 40 CFR 98.246(b)(1) to be consistent with the structure in other reporting sections, and we are renumbering the existing paragraphs (b)(1) and (b)(2).

Second, we are adding a statement in the renumbered paragraph 40 CFR 98.246(b)(2) to specify that the reporting requirements in 40 CFR 98.36(b)(9)(iii) (as numbered in today's action) for CH₄ and N₂O do not apply under subpart X because applicable reporting requirements are specified in 40 CFR 98.246(b)(5).

Third, in the renumbered 40 CFR 98.246(b)(3), we are deleting the requirement to report information required under 40 CFR 98.36(e)(2)(vii) because the referenced section specifies recordkeeping requirements, not reporting requirements. Note that one must still keep the applicable records because 40 CFR 98.247(a) references 40 CFR 98.37, which in turn requires you to keep all of the applicable records in 40 CFR 98.36(e). We are also amending the reference to 40 CFR 98.36(e)(2)(vii) to a more general reference of 40 CFR 98.36. This makes the reporting requirements consistent with the methodology for calculating emissions in 40 CFR 98.243(b).

Fourth, we are amending 40 CFR 98.246(b)(4) to clarify our intent. The first sentence in 40 CFR 98.246(b)(4) requires reporting of the total CO₂ emissions from each stack that is monitored with CO₂ CEMS; this requirement will be unchanged. We are amending the second sentence in 40 CFR 98.246(b)(4) to clarify that for each CEMS that monitors a combustion unit stack, you must estimate the fraction of the total CO₂ emissions that is from combustion of the petrochemical process off-gas in the fuel gas. This estimate will give an indication of the total petrochemical process emissions, whereas the CEMS data alone will also include emissions from combustion of supplemental fuel (if any).

Finally, as proposed, we are finalizing several amendments to 40 CFR 98.246(b)(5). In general, as noted above, the requirements in this paragraph are consistent with the requirements in 40 CFR 98.36(b)(9)(iii) (as numbered in this action). Most of the amendments to 40 CFR 98.246(b)(5) restate requirements from 40 CFR 98.36(b)(9)(iii); for example, the amendments clarify that emissions are to be reported in metric tons of each gas and in metric tons of CO₂e. However, because 40 CFR

98.36(b)(9)(iii) allows you to consider petrochemical process off-gas as a part of "fuel gas" rather than as a separate fuel, under 40 CFR 98.246(b)(5) you must also estimate the fraction of total CH₄ and N₂O emissions in the exhaust from each stack that is from combustion of the petrochemical process off-gas. In addition, because 40 CFR 98.243(b) requires you to determine CH₄ and N₂O emissions using Equation C-8 in subpart C (rather than Equation C-10), the amendments to 40 CFR 98.246(b)(5) require reporting of the HHV that you use in Equation C-8. We are also deleting the erroneous reference to Equation C-10 that was included in 40 CFR 98.246(b)(5).

Reporting requirements for the ethylene-specific option. As proposed, we are finalizing several amendments to clarify the reporting requirements in 40 CFR 98.246(c) for the combustion-based methodology that is available to the ethylene-specific option. First, we are adding a requirement to report each ethylene process ID to allow identification of the applicable process units at facilities with more than one ethylene process unit. Second, we are making editorial changes to clarify that you must estimate the fraction of total combustion emissions that is due to combustion of ethylene process off-gas, consistent with the requirements described above for combustion units that are monitored with CEMS. Third, we are replacing the requirement to report the "annual quantity of each type of petrochemical produced from each process unit" with a requirement to report the "annual quantity of ethylene produced from each process unit."

Reporting measurement device calibrations. As proposed in 40 CFR 98.246(a)(7) we are deleting the requirement for reporting of the dates and summarized results of calibrations of each measurement device under the mass balance option, and we are also adding 40 CFR 98.247(b)(4) to require retention of these records.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

- Additional methods for determining carbon content or composition of feedstocks and products were added to 40 CFR 98.244(b)(4).
- For the optional combustion method for ethylene processes, the introductory paragraph in 40 CFR 98.243(d) was edited to require

calculation of GHG emissions from "combustion units" rather than from "each combustion unit." This change makes it clear that the common pipe reporting alternative specified in 40 CFR 98.36(c)(3) of subpart C may be used when applicable, and it makes 40 CFR 98.243(d) consistent with the reporting requirements for the ethylene process option as specified in 40 CFR 98.246(c).

- For the mass balance option, 40 CFR 98.243(c)(3) was revised to specify that multiple deliveries of a particular liquid or solid feedstock in a month from the same supply source may be considered a single feedstock lot, requiring only one representative sample for carbon content analysis. This change makes the analysis requirements for feedstocks consistent with the amended requirements for fuels in 40 CFR 98.34(b)(3)(ii)(B).

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: Several commenters requested either the addition of specific carbon content or composition measurement methods in 40 CFR 98.244(b)(4) or other changes that would increase measurement flexibility. One commenter requested that EPA Method 9060 of SW-846 be added to the list of methods, and that the list of methods be modified to allow for the use of a company-specific method for measuring acetonitrile as an alternative to using EPA Method 8015 in SW-846. One commenter requested that ASTM D7633, Standard Test Method for Carbon Black—Carbon Content, be added to the list of methods because it has recently been accepted and approved by ASTM. This commenter also noted that ASTM is currently reviewing a method for carbon content in carbon black feedstock oils and requested addition of a statement indicating that once this method is approved and assigned an official number by ASTM that it is effective as of January 1, 2010. One commenter requested that EPA remove the reference to "analytical" in the phrase "other analytical methods" in proposed 40 CFR 98.244(b)(4)(xiii) (renumbered as paragraph (xv)(A) in the final amendments) so that the carbon content of ethylene oxide and water solutions

could be measured using a densitometer. One commenter stated that 40 CFR 98.244(b)(4) should be expanded to allow the use of an on-line mass spectrometer to determine the carbon content and molecular weights. One commenter stated that requirements for gas chromatography should be consistent across all subparts and that EPA should extend the requirements for the use of gas chromatographs under subpart C to subpart X. Specifically, the commenter requested that the use of gas chromatographs be allowed, "provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions." One commenter noted that the proposed amendments to subpart C added flexibility to the carbon content analysis requirements for fuels by eliminating the list of specific methods and instead allowing a broader array of methods (i.e., industry consensus standard practice, method published by a consensus-based standards organization, or results of gas chromatographic analysis). This commenter stated that the same flexibility should be allowed for feedstock and product analysis under subpart X.

Response: In the preamble to the proposed amendments we indicated that we would consider adding carbon content methods for carbon black and carbon black feedstock oil if they were approved by ASTM before publication of the final amendments. Because it has been approved by ASTM, we have added Method D7633, Standard Test Method for Carbon Black—Carbon Content, to 40 CFR 98.244(b)(4). We have not added the requested statement regarding the method for determining carbon content in carbon black feedstock oil because we cannot cite a specific method without being able to incorporate it by reference, and incorporation by reference is possible only if a copy of the method is available. However, if this method is a current industry standard practice, its use since January 1, 2010, is allowed by 40 CFR 98.244(b)(4)(xv) of the final amendments.

We have also decided to make four of the other changes suggested by commenters. First, we have added EPA Method 9060A in SW-846 because a commenter indicated that it is much more effective at detecting organic compounds in a liquid waste stream than any of the listed methods. Because none of the currently listed methods effectively detect these compounds in the waste stream, an alternative method such as EPA Method 9060A in SW-846 would already be allowed under 40 CFR

98.244(b)(4)(xv)(A) of the final amendments. However, specifically listing the method will make demonstrating compliance more straightforward.

Second, we have deleted the word "analytical" from the phrase "other analytical methods" in 40 CFR 98.244(b)(4)(xv)(A) of the final amendments so that non-analytical methods can be used. We agree with the commenter that this change is needed so that a densitometer can be used to determine the carbon content in an ethylene oxide and water solution. We also agree that a non-analytical alternative must be available in cases where the carbon content of the solution cannot safely be determined using any of the listed analytical methods or modifications of them.

Third, we have added the option from subpart C to use results from a gas chromatograph, provided the instrument is operated, maintained, and calibrated according to the manufacturer's instructions. This change means there is a common option in both subparts C and X, which we have determined is important because some materials may be a fuel in some applications and a petrochemical feedstock in others (e.g., ethylene feedstocks). With this change, a facility would not have to use two methods to determine the carbon content of the same material.

Fourth, we have added an option to use a mass spectrometer to determine the carbon content of a feedstock or product. Although a mass spectrometer would more commonly be used as one type of detector to determine the concentration of individual compounds separated in a gas chromatograph, using a mass spectrometer alone to determine the overall carbon content is also acceptable.

Finally, we have decided not to delete the list of specified methods and replace them with a general statement allowing the use of any industry consensus standard practice or method published by a consensus-based standards organization. We have received considerable input from the industry on methods that are actually being used. We conclude that the existing flexibility in the final amendments is sufficient, and that there is no need to allow the use of other unspecified methods. We recognize that this is not consistent with the methodologies allowed for determining carbon content in subpart C; however, we have concluded that this is justified given the wide variety of industries subject to subpart C versus the more narrowly-focused sources subject to subpart X.

We are not specifically allowing the use of a company-specific method for the determination of carbon content in acetonitrile because we are not convinced that it is necessary. The commenter indicated that they can use EPA Method 8015 of SW-846, and they have not indicated any problems with using this method. It is also possible that their company-specific method would qualify as a modification to a listed method that would be allowed if any of the criteria in 40 CFR 98.244(b)(4)(xv)(A) of the final amendments are met. Therefore, we have not made the requested change.

Comment: One commenter requested a modification to 40 CFR 98.243(c)(3) for carbon black production processes that specifies all deliveries of a fuel or feedstock oil in a month from the same supply source are considered to be a fuel lot, and carbon content must be determined for only one representative sample from the lot.

Response: Although we did not propose amendments to the sampling and analysis requirements in 40 CFR 98.243(c)(3), we did propose a change similar to that suggested by the commenter in 40 CFR 98.34(b)(3)(ii)(B) of subpart C for fuels. Subpart X currently requires you to determine the carbon content for at least one sample of each feedstock and product per month. In addition, if you make more than one valid carbon content measurement during the month (from separate samples), then you must average the results arithmetically. (Note that this language does not require sampling and analysis for each delivery of a feedstock. Furthermore, each delivery of the same material, even from different suppliers, is not considered to be a separate feedstock.) However, we agree with the commenter that if multiple deliveries of the same feedstock are received from the same supply source, one representative sample is sufficient for the month. Therefore, we have amended 40 CFR 98.243(c)(3) in the interest of improving the operating flexibility of the rule. We have also broadened the statement so that it applies for any liquid or solid feedstock. Please see the amended rule language to 40 CFR 98.243(c)(3).

Comment: One commenter stated that the proposed term "each combustion unit" in the introductory paragraph of 40 CFR 98.243(d) appears to preclude the use of the common pipe reporting alternative in 40 CFR 98.36(c)(3). According to the commenter, the common pipe option is appropriate for ethylene processes, and precluding it will not improve the quality of GHG emission estimates. Therefore, the

commenter requests that “each combustion unit” be changed to “combustion units.”

Response: We have made the suggested change in the final amendments because we agree with the commenter’s assessment of the proposed language. We did not intend to preclude the use of the common pipe option, as evidenced by the fact that 40 CFR 98.243(d)(2)(i) and (ii) both specify that the determination of when Tier 1 and Tier 2 procedures may be used is to be based on whether there is an existing flow meter either in the line to the combustion device or an upstream common pipe. Moreover, the reporting requirements in 40 CFR 98.246(c)(2) require reporting for each stationary combustion unit, or group of stationary sources with a common pipe.

N. Subpart Y—Petroleum Refineries

1. Summary of Final Amendments and Major Changes Since Proposal

Numerous issues have been raised by owners and operators in relation to the requirements in subpart Y for petroleum refineries. The issues being addressed by the amendments include the following:

- GHG emissions from flares.
- GHG emissions to report from combustion of fuel gas.
- GHG emissions to report from non-merchant hydrogen production process units.
- Calculating GHG emissions from fuel gas combustion.
- Calculating combustion GHG emissions from flares and asphalt blowing operations controlled by thermal oxidizer or flare.
- Molar volume conversion factors.
- Combined stacks monitored by CEMS.
- Nitrogen concentration monitoring to determine exhaust gas flow rate.
- Calculating CO₂ emissions from catalytic reforming units.
- Calculating GHG emissions from sulfur recovery plants.
- Calculating CO₂ emissions from coke calcining units.
- Calculating CO₂ emissions from process vents.
- Monitoring and QA/QC requirements.
- Reporting requirements.

GHG emissions from flares. We are finalizing corrections to 40 CFR 98.252(a) (GHGs to report) as proposed to clarify the required emissions methods for flares. We are proposing to amend the second sentence in 40 CFR 98.252(a) to correctly require reporters to “Calculate and report the emissions from stationary combustion units under

subpart C * * *” and we are proposing to add an additional sentence at the end of this section to clarify that reporters must “Calculate and report the emissions from flares under this subpart.”

GHG emissions to report from combustion of fuel gas. We are finalizing amendments to 40 CFR 98.252(a) as proposed to clarify that reporting of CH₄ and N₂O emissions is required for the stationary combustion units fired with fuel gas. As described in Section II.G of this preamble, we are also amending the definition of fuel gas.

GHG emissions to report from non-merchant hydrogen production process units. As proposed, we are amending 40 CFR 98.252(i) to clarify that reporting of only CO₂ emissions is required for non-merchant hydrogen production process units.

Calculating GHG emissions from fuel gas combustion. We are finalizing amendments to 40 CFR 98.252(a), as proposed, so that petroleum refineries subject to subpart Y can use the Tier 1 or 2 methodologies in subpart C for combustion of fuel gas when either of the following conditions exists:

- The annual average fuel gas flow rate in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 scfm at 60 °F and 14.7 psia, and either of the following conditions exists:
 - A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or
 - The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.
- The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr, and either of the following conditions exists:
 - A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or
 - The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

Calculating combustion GHG emissions from flares and asphalt blowing operations controlled by thermal oxidizer or flare. As proposed, we are finalizing amendments to 40 CFR 98.253 to renumber existing Equations Y-1 and Y-16 as Equations Y-1a and Y-16a, and adding the more detailed Equations Y-1b and Y-16b that provide more detailed alternative methods for

calculating emissions. We are also finalizing corresponding amendments in 40 CFR 98.256 as proposed to require reporting of which equation was used and, if the new equations are used, reporting of the additional equation parameters.

Molar volume conversion factors. We are finalizing amendments to Equations Y-1, Y-3, Y-6, Y-12, Y-18, Y-19, Y-20, and Y-23 in subpart Y as proposed to provide two alternative values of MVC depending on the standard conditions output by the flow monitors. For reasons outlined in the “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA-HQ-OAR-2008-0508), we are also finalizing a similar amendment to Equation Y-2, as a logical outgrowth of the proposal and comments received to provide two alternative values of MVC in this equation (if mass flow monitors are used) depending on the standard conditions at which the higher heating value is determined. Additionally, the reporting requirements related to each of these equations are being amended to include reporting of the value of MVC used to support the calculations and to allow verification of the reported emissions.

Combined stacks monitored by CEMS. As proposed, we are amending the language in 40 CFR 98.253(c)(1)(ii) and also the reporting requirements in 40 CFR 98.256(f)(6) to generalize the language to include other CO₂ emission sources, not just a CO boiler.

Nitrogen concentration monitoring to determine exhaust gas flow rate. As proposed, we are amending 40 CFR 98.253(c)(2)(ii) to renumber Equation Y-7 as Equation Y-7a and to add an Equation Y-7b to provide an alternative N₂ concentration monitoring approach for determining the exhaust gas flow rate. We are also finalizing reporting requirements in 40 CFR 98.256(f)(9) to report the input parameters for Equation Y-7b if it is used.

Calculating CO₂ emissions from catalytic reforming units. We are finalizing amendments to the definition of the coke burn-off quantity, CB_Q, and the term “n” in Equation Y-11 in 40 CFR 98.253(e)(3) as proposed to clarify the application of Equation Y-11 to continuously regenerated catalytic reforming units.

Calculating GHG emissions from sulfur recovery plants. We are amending 40 CFR 98.253(f) as proposed to add “and for sour gas sent off site for sulfur recovery” to clarify that this calculation methodology applies “For on-site sulfur recovery plants and for sour gas sent off site for sulfur recovery, * * *” and to

allow non-Claus sulfur recovery plants to alternatively follow the requirements in 40 CFR 98.253(j) for process vents. We also are finalizing amendments to the reporting requirements in 40 CFR 98.256(h) as proposed to include the type of sulfur recovery plant, an indication of the method used to calculate CO₂ emissions, and reporting requirements for non-Claus sulfur recovery plants that elect to follow the requirements in 40 CFR 98.253(j) for process vents.

Calculating CO₂ emissions from coke calcining units. We are amending the definition of M_{dust} (the mass of dust collected in the dust collection system) in Equation Y-13 in 40 CFR 98.253(g) as proposed to clarify that dust recycled back to the coke calciner is not included in the mass of dust collected in the dust collection system (M_{dust}). We also are finalizing amendments to 40 CFR 98.256(i)(5), as proposed, to require facilities that use Equation Y-13 to indicate whether or not the collected dust is recycled to the coke calciner.

Calculating CO₂ emissions from process vents. We are finalizing amendments to the process vent requirements in 40 CFR 98.253(j) as proposed to account for the additional sources that may elect to use Equation Y-19, specifically non-Claus sulfur recovery units (as previously described) and uncontrolled blowdown vents (inadvertently not referenced). We are also amending the reporting requirements for process vents in 40 CFR 98.256(l) as proposed to clarify that the requirements apply to each process vent, and 40 CFR 98.256(l)(5) to require an indication of the measurement or estimation method for the volumetric flow rate and the mole fraction of the GHG in the vent.

Finally, we are finalizing amendments to 40 CFR 98.253(n) as proposed to delete the words “equilibrium” and “product-specific” to clarify that the true vapor phase of the loading operation system should be used when determining whether the vapor-phase concentration of methane is 0.5 volume percent or more.

Monitoring and QA/QC requirements. We are finalizing amendments to the monitoring and QA/QC requirements in subpart Y, 40 CFR 98.254 as proposed, except as provided below. We proposed amendments to require all gas flow meters on process vents subject to reporting under 40 CFR 98.253(j) to comply with the monitoring requirements in 40 CFR 98.254(f). However, for the reasons set forth in the Response to Comments (Section N.2. of this preamble), we are finalizing amendments for gas flow meters on

process vents subject to reporting under 40 CFR 98.253(j) to comply with the monitoring requirements in 40 CFR 98.254(c).

A summary of the amendments to the monitoring and QA/QC requirements that we are finalizing as proposed is below. Paragraph (a) of 40 CFR 98.254 is amended to include also the phrase “sources that use a CEMS to measure CO₂ emissions according to subpart C of this part * * *” to separate further these sources from those that are covered by 40 CFR 98.254(b). We also are rewording the phrase “follow the monitoring and QA/QC requirements in § 98.34” with “meet the applicable monitoring and QA/QC requirements in § 98.34” to clarify that the monitors must meet the requirements for the specific tier for which monitoring was required (Tier 3 sources will comply with the Tier 3 requirements; Tier 4 sources will comply with the Tier 4 requirements; *etc.*).

Because the QA/QC requirements for CO₂ CEMS that were formerly included in 40 CFR 98.254(l) will be included in the amended paragraph 40 CFR 98.254(a), we are removing 40 CFR 98.254(l).

Paragraph (b) of 40 CFR 98.254 is amended to clarify that these requirements apply to gas flow meters, gas composition monitors, and heating value monitors other than those subject to 40 CFR 98.254(a). We are correcting the reference to “paragraphs (c) through (e)” to correctly reference “paragraphs (c) through (g)” as gas monitoring system requirements are specified in 40 CFR 98.254(c) through (g). We are also clarifying that the calibration requirements in 40 CFR 98.3(i) only apply to gas flow meters and allowing recalibration of gas flow meters biennially (every two years), at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used. Paragraph (b) of 40 CFR 98.254 is also amended to clarify that gas composition and heating value monitors must be recalibrated either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

Paragraph (c) of 40 CFR 98.254 is amended to clarify that the flare or sour gas flow meters must be calibrated (in addition to operated and maintained) using either a method published by a consensus-based standards organization (*e.g.*, ASTM, API, *etc.*) or the procedures specified by the flow meter manufacturer. The ± 5 percent accuracy specification is being removed from 40

CFR 98.254(c). We are also amending 40 CFR 98.254(c) by removing the list of methods as this is redundant to the existing phrase, “a method published by a consensus-based standards organization.”

Paragraphs (d) and (e) of 40 CFR 98.254 are amended to allow the use of any chromatographic analysis to determine flare gas composition and high heat value, as an alternative to the methods listed in 40 CFR 98.254(d) and (e), provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions. The methods used for operation, maintenance, and calibration of the gas chromatograph must be documented in the written monitoring plan for the unit under 40 CFR 98.3(g)(5). Paragraph (d) in 40 CFR 98.254 is also amended to apply to all gas composition monitors, other than those included in 40 CFR 98.254(g), and not just flare gas composition monitors.

We are also amending 40 CFR 98.254(d) to specify that the methods in this paragraph are also to be used for determining average molecular weight of the gas, which is needed in Equations Y-1a and Y-3. We are also adding an additional method (ASTM D2503-92) to this section for determining average molecular weight.

We are making a number of amendments to 40 CFR 98.254(f). The term “exhaust gas flow meter” is replaced with the term “gas flow meter,” as proposed.

We are retaining 40 CFR 98.254(f)(3) and portions of 40 CFR 98.254(f)(1) but only as general, supplementary guidelines for flow monitor installation and operation. Thus, we are amending 40 CFR 98.254 to require that reporters must do all of the following:

- Install, operate, calibrate, and maintain each stack gas flow meter according to the requirements in 40 CFR 63.1572(c);
- Locate the flow monitor at a site that provides representative flow rates (avoiding locations where there is swirling flow or abnormal velocity distributions); and
- Use a monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in 40 CFR 98.6).

We are making a technical correction to 40 CFR 98.254(g) to correct the cross-reference from 40 CFR 63.1572(a) to 40 CFR 63.1572(c).

We are amending 40 CFR 98.254(h) to require calibration of mass measurement equipment according to the procedures specified by National Institute of Standards and Technology (NIST)

Handbook 44 or the procedures specified by the manufacturer, and removing reference to the calibration requirements in 40 CFR 98.3(i).

Reporting requirements. This section covers reporting requirements that have not been described in previous sections of this preamble.

We are amending the reporting requirements in 40 CFR 98.256(e)(6) and (8) for Equations Y-1 (renumbered to Y-1a) and Y-2, respectively, to require reporting of whether daily or weekly measurement periods are used, for verification purposes.

In 40 CFR 98.256(f)(6), 40 CFR 98.256(h)(6), and 40 CFR 98.256(i)(6), we are amending the references to 40 CFR 98.36(e)(2)(vi) to reference 40 CFR 98.36 more generally. This will make the references consistent with the associated requirements in 40 CFR 98.253.

We are amending 40 CFR 98.256(f) to require reporting of the unit-specific emission factor for CH₄ and N₂O, if used, in the newly designated 40 CFR 98.256(f)(11) and (12), respectively.

We are amending 40 CFR 98.256(i)(8) to make it consistent with the information collected in 40 CFR 98.245(i)(7).

We are also amending 40 CFR 98.256(j)(2) to clarify that the reporting requirements for asphalt blowing apply at the unit level.

We are also amending 40 CFR 98.256(o) to re-organize the reporting requirements to separate and clarify the reporting requirement for storage tanks used for processing unstabilized crude oil from those reporting requirements for other types of storage tanks.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

- Amending Equation Y-2 in subpart Y to provide two alternative values of MVC in this equation (if mass flow monitors are used) depending on the standard conditions at which the higher heating value is determined.
- Amending requirements for gas flow meters on process vents subject to reporting under 40 CFR 98.253(j) to comply with the monitoring requirements in 40 CFR 98.254(c) rather than 40 CFR 98.254(f).

2. Summary of Comments and Responses

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

Several comments were received on this subpart. Responses to additional comments received can be found in the document, "Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule" (see EPA-HQ-OAR-2008-0508).

Comment: One commenter stated that they have identified gas streams that would otherwise fit the requirements for the use of the Tier 1 or Tier 2 methodologies, as proposed in 40 CFR 98.252(a)(1) and (2), if it were not for the fact that they are equipped with flow meters. According to the commenter, these streams are not what industry would define as "refinery fuel gas" but would fall under the realm of "fuel gas" as originally defined in 40 CFR 98.6 in the October 30, 2009, final Part 98, and in the amended definition. These can include streams that are process off-gas or vent gases with properties much different from traditional "refinery fuel gas" streams and are not part of the refinery's fuel gas system. According to the commenter, these off-gas streams may not be sampled currently. The commenter asserted that many of these streams are difficult to sample (for example, because of low pressure) or may present hazardous sampling conditions. According to the commenter, the added rigor associated with Tier 3 requirements is not justified for the increased safety risk, considering the very small contribution of emissions (on the order of 0.1 percent of a refinery's total greenhouse gas emissions as estimated by the commenter).

Response: The proposed amendments provided limited exclusions to the Tier 3 requirement for very small fuel gas lines or combustion units that are not equipped with a flow meter. As noted in the preamble of the August 11, 2010, proposed amendments, the exclusion was specifically targeted to prevent the need to install flow meters for these small fuel gas lines. EPA noted that "[i]f flow meters are in place at the process heater or at a common pipe location, we consider that the Tier 3 monitoring requirements are reasonable and justified." (See 75 FR 48772.) The commenter indicated that these gas streams could have a significantly different composition than typical refinery fuel gas, which suggests the default fuel gas factor would have considerable uncertainty for these gas streams, further indicating that Tier 3 sampling is necessary. While we recognize that there are inherent safety issues with sampling any fuel gas streams, the commenter has not provided any supporting information for

the assertion that sampling these "process off-gas or vent gases" is more hazardous than other fuel gas streams at the refinery. Therefore, we are not expanding the proposed exclusion to the Tier 3 methodology for fuel gas lines that have a flow meter already installed in the line or upstream common pipe. We also note that today's final amendments are not imposing new requirements to sample these fuel gas streams; the October 30, 2009, final Part 98 already required these fuel gas streams to be sampled for carbon content no less than once per calendar week.

Comment: One commenter objected to the proposed revision of 40 CFR 98.254(f) to also require exhaust gas flow meters associated with process vents (*i.e.*, subject to 40 CFR 98.253(j) requirements) to be installed, operated, calibrated and maintained according to the Petroleum Refineries NESHAP (40 CFR part 63, subpart UUU) requirements in 40 CFR 63.1572(c). According to the commenter, the Petroleum Refineries NESHAP requirements in 40 CFR 63.1572(c) contain provisions that are more stringent than the monitoring and QA/QC requirements throughout Part 98. For example, 40 CFR 63.1572(c) requires each monitoring system to have valid hourly average data from at least 75 percent of the hours during which the process operated and to complete a minimum of one cycle of operation for each successive 15-minute period with a minimum of four successive cycles of operation to have a valid hour of data (or at least two if a calibration check is performed during that hour or if the continuous parameter monitoring system is out-of-control). The commenter stated that, since the flow monitoring requirements for the Petroleum Refineries NESHAP in 40 CFR 63.1572(c) were established to demonstrate compliance with emission limits, they should not be used as a template for requirements of flow metering for GHG reporting. The commenter recommended that the process vent exhaust flow meter requirements should be consistent with the requirements in 40 CFR 98.254(c) for flare and sour gas flow meters.

Response: We proposed to include the requirements for flow meters used to comply with the 40 CFR 98.253(j) for process vents within the monitoring provisions of 40 CFR 98.254(f) because these meters are exhaust gas flow meters rather than fuel gas flow meters. However, we agree with the commenter that the inclusion of flow meters used to comply with the 40 CFR 98.253(j) within the monitoring provisions of 40 CFR 98.254(f) added new requirements

to these flow meters. While we believe that the flow meter requirements in 40 CFR 63.1572(c) of the Petroleum Refineries NESHAP are reasonable requirements for exhaust gas flow meters in general (40 CFR 63.1572(c) are requirements for parameter monitoring systems, not continuous emission monitoring systems), we agree with the commenter that it is inappropriate to add these requirements to process vent flow meters at this juncture. Furthermore, the provisions in 40 CFR 98.253(j) allow use of process knowledge or engineering calculations as an alternative to direct flow measurement. As such, it is incongruous to subject facilities that have flow meters on these process vents to additional requirements when facilities that do not have flow meters on these process vents may use process knowledge or engineering calculations. Therefore, we are finalizing requirements for flow meters used to comply with 40 CFR 98.253(j) for process vents to meet the monitoring provisions of 40 CFR 98.254(c) rather than 40 CFR 98.254(f) as was required per the October 30, 2009 final Part 98.

O. Subpart AA—Pulp and Paper Manufacturing

1. Summary of Final Amendments and Major Changes Since Proposal

We are amending 40 CFR 98.273(a)(1), (b)(1) and (c)(1) to clarify that owners and operators may choose to use a tier other than Tier 1 from 40 CFR 98.33 to calculate fossil-fuel based CO₂ emissions.

We have removed the CO₂ emission factors from Table AA-2 and revised 40 CFR 98.273(c)(1) to direct owners and operators to use the CO₂ emission factors from Table C-1 of subpart C to calculate CO₂ emissions from lime kilns.

With respect to calculating CH₄ and N₂O emissions from fossil fuel combustion at lime kilns, and consistent with the amendments to allow use of higher tiers than Tier 1 for units subject to subpart AA, we are amending 40 CFR 98.273(a)(2), (b)(2), and (c)(2) to allow reporters to also use site-specific high heating values, as opposed to default values, when calculating CH₄ and N₂O emissions. We are making harmonizing amendments to the definition of EF under Equation AA-1 to clarify that default or site-specific emission factors may be used. Similarly, we are amending 40 CFR 98.276(e) to reflect the option to use default or site-specific values.

We are clarifying through this final rule that emissions from the combustion of wastewater treatment sludge are

calculated using the emission factors included in Table C-1. We have determined that this sludge falls within the definition of “Wood and Wood Residuals” included in Table C-1. Therefore, per 40 CFR 98.33(b)(1)(iii), emissions from the combustion of this type of sludge may be determined using Tier 1 in subpart C. In order to further clarify this, we are adding the definition of “Wood and Wood Residuals” to 40 CFR 98.6 and including wastewater process sludge from paper mills in this definition, as further described in Section II.F of this preamble.

We are adding solid petroleum coke to both Table C-1 and Table AA-2. We have concluded that it is not necessary to have emission factors for petroleum coke specific to kraft calciners in Table AA-2 because we do not believe that any kraft calciners are combusting this fuel, nor were any comments received suggesting this was not the case.

There were no comments received specifically on subpart AA, therefore the amendments are being finalized as proposed.

P. Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

1. Summary of Final Amendments and Major Changes Since Proposal

Threshold for natural gas local distribution companies. We are amending 40 CFR Table A-5 of subpart A of 40 CFR part 98 to establish an applicability threshold so that only local distribution companies (LDCs) that deliver 460,000 thousand standard cubic feet (mscf) or more of natural gas per year are subject to the reporting rule. No major changes have been made since proposal.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA-HQ-OAR-2008-0508).

Comment: Two commenters requested that EPA apply the 460,000 thousand standard cubic feet (mscf) applicability threshold throughout 40 CFR part 98 wherever a threshold is expressed in mtCO₂e. Specifically, they contended that 40 CFR 98.2(i)(1) and (2) should be changed to allow LDCs to stop reporting if they deliver less than 460 million cubic feet (mmcf) for 5 consecutive years or less than 276 mmcf for 3

consecutive years (25,000 mtCO₂e is approximately equivalent to the CO₂ emissions from the combustion of 460 mmcf of natural gas and 15,000 mtCO₂e is approximately equivalent to 276 mmcf of natural gas). The commenters urged EPA to clarify that the threshold for natural gas distributors (460,000 mscf) is equivalent to the threshold of 25,000 mtCO₂e wherever that metric ton threshold appears in the rule.

Response: EPA has finalized an applicability threshold for LDCs of 460,000 mscf or more of natural gas delivered per year. As noted by the commenters, we decided that it would be easier for LDCs to determine whether or not they were above a reporting threshold expressed in mscf than if that threshold were expressed in metric tons of carbon dioxide equivalent for the first year of this reporting program.

However, we have not changed the conditions for ceasing reporting. In the 2009 final rule, 40 CFR 98.2(i) states, “Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.” As noted by the commenter, facilities and suppliers can cease reporting when reported emissions are below 25,000 mtCO₂e for five consecutive years or below 15,000 mtCO₂e for three consecutive years, as specified in 40 CFR 98.2(i)(1) and (i)(2), respectively. It is clear in the final rule that other than these two exceptions, a facility or supplier must continue to report even if the facility or supplier no longer meets the threshold for reporting.

EPA has concluded that applying a consistent threshold, expressed in mtCO₂e, in 98.2(i)(1) and 98.2(i)(2) for all reporters levels the playing field for all reporters and is most logical. EPA does not intend to provide equivalent thresholds under 40 CFR 98.2(i) for various categories because it becomes too cumbersome. LDCs are required to report, under 40 CFR 98.406(b)(8), the total annual CO₂ mass emissions that would result from complete combustion of the natural gas delivered to end-users. By performing this required calculation, LDCs have the necessary data to determine whether they may cease reporting.

Q. Subpart OO—Suppliers of Industrial Greenhouse Gases

1. Summary of Final Amendments and Major Changes Since Proposal

We are making several changes to subpart OO to respond to concerns raised by producers of fluorinated GHGs regarding the scope of the monitoring and reporting requirements, and clarify the scope and due dates for certain reporting and recordkeeping requirements.

Producers of fluorinated GHGs requested that EPA clarify that subpart OO does not apply to fluorinated GHGs that are either emitted or destroyed at the facility before the fluorinated GHG product is packaged for sale or for shipment to another facility for destruction; are produced and transformed at the same facility; or occur as low-concentration constituents (e.g., impurities) in fluorinated GHG products. The producers also requested that EPA amend the rule to account for the fact that some fluorinated GHGs do not have global warming potential values (GWPs) listed in Table A-1 of subpart A. For fluorinated GHGs without GWPs in Table A-1, facilities cannot calculate CO₂-equivalent production as required by subpart A, and importers and exporters cannot take advantage of the reporting exemptions for small shipments under 40 CFR 98.416(c) and (d), which are expressed in CO₂-equivalents.

In response to the concern regarding fluorinated GHGs that are emitted or destroyed before the product is packaged for sale, we are amending the definition of “produce a fluorinated GHG” at 40 CFR 98.410(b) to explicitly exclude the “creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at § 98.414(a).” We are also removing the requirements at 40 CFR 98.414(j) and 98.416(a)(4) to monitor and report the destruction of fluorinated GHGs “that are not included in the calculation of the mass produced in § 98.413(a) because they are removed from the production process as by-products or wastes.” Finally, we are modifying the requirements at 40 CFR 98.414(h), 98.416(a)(3), and 98.416(a)(11) to limit them to the mass of each fluorinated GHG that is fed into the destruction device (or “destroyed” in the case of 40 CFR 98.416(a)(3)) and that was previously produced as defined at 40 CFR 98.410(b).

These amendments will clarify that the scope of subpart OO is that which EPA has always intended, and they will modify the destruction monitoring and reporting requirements to be fully

consistent with that scope. As noted in the preamble to the final Part 98 (74 FR 56259), and in the response to comments document, the intent of subpart OO is to track the quantities of fluorinated GHGs entering and leaving the U.S. supply of fluorinated GHGs. Specifically, subpart OO is intended to address production of fluorinated GHGs, not emissions or destruction of fluorinated GHGs that occur during the production process.

As noted in the proposed Part 98 (74 FR 16580), the production measurement at 40 CFR 98.414(a) could occur wherever it traditionally occurs, e.g., at the inlet to the day tank or at the shipping dock, as long as the subpart OO monitoring requirements were met (e.g., one-percent precision and accuracy for the mass produced and for container heels, if applicable). Emissions upstream of the production measurement will be subject to the recently promulgated subpart L, which was signed by EPA Administrator Lisa Jackson on November 8, 2010 and are not part of the subpart OO source category.

We are also amending 40 CFR 98.416(a)(3) and (a)(11) to limit the monitoring and reporting of destroyed fluorinated GHGs to those destroyed fluorinated GHGs that were previously “produced” under today’s revised definition.⁶ Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction, and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated. While monitoring of some destroyed streams appears to pose significant technical challenges,⁷ monitoring of quantities of

⁶ In Part 98, EPA required the monitoring of all streams being destroyed because it was our understanding, based on conversations with fluorinated GHG producers, that the mass flow of destroyed fluorinated GHG streams was routinely monitored. To arrive at the quantities being removed from the supply, EPA required facilities to estimate the share of the total quantity of fluorinated GHGs destroyed that consisted of fluorinated GHGs that were not included in the calculation of the mass produced. This share could then be subtracted from the total to arrive at the amounts destroyed that were removed from the supply. In other words, monitoring and reporting of the destruction of fluorinated GHGs that were not included in the mass produced was required in order to estimate the destruction of fluorinated GHGs that had been produced.

⁷ These include (1) low-pressure conditions that make it challenging to achieve good accuracies and precisions and under which the installation of a flowmeter may lead to low- or no-flow conditions, interfering with operations upstream of the meter, (2) corrosive conditions that require the use of Tefzel-lined flow meters, which are currently available in a limited range of sizes and precisions, and (3) variations in stream flow rates and compositions that are associated with purging of

fluorinated GHGs that were previously produced does not. These quantities can be weighed and analyzed by the facility upon receipt or upon the facility’s conclusion that they cannot be brought back to the specifications for new or reusable product.

In response to the concern regarding fluorinated GHGs that are produced and transformed at the same facility, we are amending the definition of “produce a fluorinated GHG” to exclude “the creation of intermediates that are created and transformed in a single process with no storage of the intermediates.” We are also amending the definition of “produce a fluorinated GHG” in 40 CFR 98.410(b) to explicitly include “the manufacture of a fluorinated GHG as an isolated intermediate for use in a process that will result in its transformation either at or outside of the production facility.” We are also adding a definition of “isolated intermediate” to 40 CFR 98.418. Finally, we are adding provisions to 40 CFR 98.414, 98.416, and 98.417 to clarify that isolated intermediates that are produced and transformed at the same facility are exempt from subpart OO monitoring, reporting, and recordkeeping requirements respectively.

As noted by the producers, fluorinated GHGs that are produced and transformed at the same facility never enter the U.S. supply of industrial greenhouse gases; thus, they do not need to be reported under subpart OO. This is true both of isolated intermediates and of intermediates that are created and transformed in a single process with no storage of the intermediate. However, while we are excluding the latter from the definition of “produce a fluorinated GHG,” we are including the former in that definition. This is because the manufacture of isolated intermediates, which can lead to emissions of those intermediates, will be of interest under the recently promulgated subpart L and it is desirable to use the same definition of “produce a fluorinated GHG” for subpart L as for subpart OO for consistency and clarity. Thus, instead of excluding the manufacture of isolated intermediates that are transformed at the same facility from the definition of “produce a fluorinated GHG,” we are adding provisions to exclude it from the subpart OO monitoring, reporting, and recordkeeping requirements. We are also adding a definition of “isolated

vessels and columns and that make it difficult to select a meter that will measure the full range of flows to the required accuracy and precision.

intermediate” that is the same as that for the recently promulgated subpart L.

In response to the concern regarding fluorinated GHGs that occur as low-concentration constituents of fluorinated GHG products, we are defining and excluding low-concentration constituents from the monitoring, reporting, and recordkeeping requirements for fluorinated GHG production, exports, and imports. For purposes of production and export, we are defining a low-concentration constituent in 40 CFR 98.418 as a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.1 percent by mass. This concentration is the same as that used in the definition of “trace concentration” used elsewhere in subpart OO. It is also consistent with industry purity standards for HFC refrigerants (Air-Conditioning, Heating, and Refrigeration Institute (AHRI) 700), for SF₆ used as an insulator in electrical equipment (International Electrotechnical Commission (IEC) 60376), and for perfluorocarbons and other fluorinated GHGs used in electronics manufacturing (Semiconductor Equipment and Materials International (SEMI) C3 series). To meet these standards, which set limits that range from less than 0.1 percent to 0.5 percent for all fluorinated GHG impurities combined, fluorinated GHG producers are likely to have identified and quantified the concentrations of impurities at concentrations at or above 0.1 percent for the products subject to the standards. Finally, below concentrations of 0.1 percent, fluorinated GHG impurities are not likely to have a significant impact on the GWP of the product. For example, if a low-concentration constituent occurs in concentrations of just less than 0.1 percent and has a GWP that is ten times as large as the GWP of the main constituent of the product, it will increase the weighted GWP of the product by just less than one percent.

To ensure that fluorinated GHG production facilities rely on data of known and acceptable quality when determining whether or not to report a minor fluorinated GHG constituent of a product, we are adding product sampling and analytical requirements at 40 CFR 98.414(n), corresponding calibration requirements at 40 CFR 98.414(o), and a corresponding reporting requirement at 40 CFR 98.416(f). We are also clarifying in 40 CFR 98.414(a) how to calculate production of each fluorinated GHG constituent of a product.

For purposes of fluorinated GHG imports, we are defining a “low-concentration constituent” in 40 CFR 98.418 as a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.5 percent by mass. We are defining a higher concentration for fluorinated GHG imports than for fluorinated GHG production and exports because importers are less likely than producers to have detailed information on the identities and concentrations of minor fluorinated GHG constituents in their products.

In response to the concerns regarding fluorinated GHGs that do not have GWPs listed in Table A–1, we are amending subpart A to exempt such compounds from the general subpart A requirement to report supply flows in terms of CO₂ equivalents and revising the reporting exemptions for import and export of small shipments to be in terms of kilograms of fluorinated GHGs or N₂O, rather than tons of CO₂-equivalents. The amendment to subpart A is discussed in more detail in Section II.F of this preamble. The exemptions for import and export will be applied to shipments of less than 25 kilograms of fluorinated GHGs or N₂O rather than to shipments of less than 250 metric tons of CO₂e. This will enable small shipments of fluorinated GHGs to be exempt from reporting regardless of whether or not the fluorinated GHG has a GWP listed in Table A–1.

Other corrections. We are also amending the reporting and recordkeeping provisions in subpart OO to clarify those requirements and to correct internal inconsistencies in the subpart.

We are amending the reporting requirements in 40 CFR 98.416(a)(15) and (c)(10) to remove N₂O from the list of GHGs that must be reported when they are transferred off site for destruction, because N₂O transferred off site for destruction is not required to be monitored.

We are amending 40 CFR 98.416(b) and (e) to clarify the due dates of the one-time reports required by those paragraphs. The due date for the one-time reports is March 31, 2011, or within 60 days of commencing fluorinated GHG destruction or production (as applicable). The due date in 40 CFR 98.416(e) in subpart OO was originally April 1, 2011, and there was no provision for fluorinated GHG destruction or production commenced after that date.

We are amending the recordkeeping requirements in 40 CFR 98.417(a)(2) to correct and update an internal reference. The correct reference is to “§ 98.414(m)

and (o),” instead of “§ 98.417(j) and (k).” We are amending 40 CFR 98.417(b) to remove the reference to the “annual destruction device outlet reports” in 40 CFR 98.416(e) since no such reporting requirement exists.

Finally, we are amending 40 CFR 98.417(d)(2) to correct a typographical error; that paragraph should refer to “the invoice for the export,” rather than for the “import.”

EPA is making one clarifying editorial change in the final rule amendments that was not in the proposed amendments. As discussed above and in the preamble to the proposed amendments, 40 CFR 98.414(h) requires facilities to measure the mass of each fluorinated GHG that is fed into the destruction device and that was previously produced. If the mass being fed into the destruction device includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, facilities must estimate the concentrations of the fluorinated GHGs being destroyed. They must then multiply these concentrations by the mass measurement to obtain the mass of the fluorinated GHGs fed into the destruction device. In the proposed paragraph (h), the final sentence read, “You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG destroyed.” To be consistent with the beginning of the paragraph and to be mathematically correct, this sentence has been corrected in the final rule to read, “You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.” As specified in Equation OO–4 of 40 CFR 98.413(d), the mass of the fluorinated GHG destroyed is obtained by multiplying the mass of the fluorinated GHG fed into the destruction device by the destruction efficiency of the destruction device.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA–HQ–OAR–2008–0508).

Comment: Two commenters expressed concerns that exempting low-concentration constituents of products from monitoring and reporting would exempt a significant amount of

emissions from reporting. These commenters requested additional information on the GWP of these low-concentration constituents and on the emissions affected by the exemption.

Response: We analyzed the potential impact of low-concentration constituents on the total calculated flows of fluorinated GHGs into the U.S. economy, considering both the possible masses of the low-concentration constituents and their CO₂-equivalents. We concluded that at a level of 0.1 percent of production and 0.5 percent of imports, identification of such constituents would have a negligible impact on the total calculated flows of fluorinated GHGs into the U.S. supply. It is important to note that, under the exemption for low-concentration constituents, the masses and CO₂e of low-concentration constituents are not equated to zero. Instead, the mass of the low-concentration constituent is assigned to the main constituent of the product, and the GWP is assumed to be that of the main constituent of the product. Only if the GWP or atmospheric lifetime of the low-concentration constituent is significantly higher than that of the main constituent is there a potential concern associated with these assumptions.

As noted in the preamble to the proposed rule, low-concentration constituents are generally by-products of the reaction used to produce the fluorinated GHG product. Although we do not have information on every product and by-product combination, we believe, based on the examples of which we are aware, that by-products rarely have GWPs that are more than ten times as large as that of the product. We analyzed the potential impact of a by-product that had ten times the GWP of the product on the weighted GWP of the combination of the two. At a concentration of 0.1 percent, the by-product would raise the weighted GWP (and CO₂e) above that of the product by just under one percent. Given that the impacts of most low-concentration constituents are likely to fall below this level, we do not consider them significant.

We also performed an analysis in which we conservatively assumed that every HFC, PFC, and SF₆ product had a PFC by-product that was shipped along with it at a concentration of 0.1 percent. This was intended to address the possibility that low-concentration constituents had very long atmospheric lifetimes. Based on this worst-case assumption, the quantity of PFCs flowing into the U.S. fluorinated GHG supply was increased by less than 10

percent. It is extremely unlikely that every HFC, PFC, and SF₆ product has a PFC by-product; in fact, the highest-volume products, the HFCs, are unlikely to have PFC by-products. Therefore, in consideration of this analysis and the GWP analysis, we have concluded that the exemption for low-concentration constituents is very unlikely to lead to significant errors in our understanding of potential emissions of fluorinated GHGs from the U.S. supply.

Comment: Two commenters expressed concerns regarding the proposal to exclude from subpart OO fluorinated GHGs that are emitted or destroyed before the fluorinated product is packaged for sale. They requested that EPA ensure that these emissions were fully captured under the reporting rule (e.g., subpart L) and requested that EPA document the magnitude of these emissions and the identities and GWPs of the compounds emitted.

Response: As proposed, we are excluding from the definition of “produce a fluorinated GHG” the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement. As discussed in the preamble to the proposed amendments, such fluorinated GHGs never enter the U.S. supply of fluorinated GHGs, and the goal of subpart OO is to monitor fluorinated GHG flows into and out of this supply. However, the recently promulgated subpart L requires monitoring and reporting of emissions that occur before the production measurement. We have worked to ensure that no fluorinated GHG emissions from fluorinated GHG production are “missed” under the combined oversight of these two subparts. The magnitudes, identities, and GWPs of the emissions that will be reported under subpart L of 40 CFR part 98 are discussed in the preamble to the proposed rule including subpart L (75 FR 18652, April 12, 2010) and in the Technical Support Document for subpart L.

R. Subpart PP—Suppliers of Carbon Dioxide

1. Summary of Final Amendments and Major Changes Since Proposal

We are removing the words “each” from 40 CFR 98.422(a) and (b). This change will align this section with the requirements of the rest of subpart PP, which allow for monitoring of an aggregated flow of CO₂, versus monitoring at each production well or process unit, if the monitoring is done at a gathering point downstream of

individual production wells or production process units.

We are allowing suppliers to calculate the annual mass of CO₂ supplied in containers by using weigh bills, scales, load cells, or loaded container volume readings as an alternative to flow meters. We are making multiple amendments to the regulatory text to accommodate this provision. First, we are redesignating 40 CFR 98.423(b) as 40 CFR 98.423(c) and adding a new 40 CFR 98.423(b) with calculation procedures for CO₂ supplied in containers. Second, we are amending the first sentence of 40 CFR 98.423(a) to allow use of the alternative procedures in 40 CFR 98.423(b). Third, we are adding new QA/QC procedures for suppliers of CO₂ in containers to 40 CFR 98.424(a)(2). Fourth, we are adding missing data procedures for suppliers of CO₂ in containers to 40 CFR 98.425(d) and specifying that the missing data procedures in 40 CFR 98.425(a) are for suppliers using flow meters. Finally, we are making multiple amendments to regulatory text in 40 CFR 98.426 so that all data collected with weigh bills, scales, load cells, or loaded container volume readings must be reported just as for all data collected with flow meters.

We are removing the requirement that CO₂ measurement must be made prior to subsequent purification, processing, or compression at 40 CFR 98.423(a)(1), (a)(2), and (b) (which we are redesignating as 40 CFR 98.423(c)). Because the purpose of subpart PP is to collect accurate data on CO₂ supplied to the economy, we have concluded that measurements made after purification, compression, or processing will continue to meet the level of data quality and accuracy needed with respect to subpart PP, while minimizing the burden on industry and providing greater flexibility in measuring CO₂ streams.

To ensure that all reporters account for the appropriate quantity of CO₂ in situations where a CO₂ stream is segregated such that only a portion is captured for commercial application or for injection and where a flow meter is used, we are making a number of amendments. First, we are adding language at 40 CFR 98.424(a) regarding flow meter location. Reporters who have a flow meter(s) on the main, captured CO₂ stream(s) only must locate the flow meter(s) after the point(s) of segregation. Reporters who have a flow meter(s) on the main, captured CO₂ stream and a subsequent flow meter(s) on the CO₂ stream(s) diverted for on-site use and who choose to use the subsequent flow meter(s) to calculate CO₂ supply (*i.e.* the

two meter method) must locate the main flow meter(s) prior to the point(s) of segregation and the subsequent flow meter(s) on the CO₂ stream(s) for on-site use after the point(s) of segregation. We are also amending existing language in 40 CFR 98.424(a) to reference this new requirement. Second, we are amending 40 CFR 98.423(a)(3) to provide reporters using the two meter approach a new equation (Equation PP-3b) to calculate total CO₂ supplied. As a harmonizing change, we are redesignating Equation PP-3 as Equation PP-3a. Third, we are amending 40 CFR 98.426(c) so that reporters using the new Equation PP-3b are required to report the equation inputs and output and the location of flow meters with respect to the point of segregation.

Because the amendments will allow flow meters to be located after purification, compression, or processing, we are adding data reporting requirements in 40 CFR 98.426 to collect additional information on flow meter location. Specifically, we are adding that facilities will report information on the placement of each flow meter used in relation to the points of CO₂ stream capture, dehydration, compression, and other processing. Knowing where in the production process the flow meter is located will enable EPA to effectively compare data across reporters and learn about the efficacy of various CO₂ stream capture processes.

We are specifying standard conditions under subpart PP as a temperature and an absolute pressure of 60 °F and 1 atmosphere. It is our understanding that 60° F and 1 atmosphere (which is equivalent to 14.7 psia) are more commonly used by the industries covered by subpart PP.

We are making several amendments to allow the reporter to determine the mass of a CO₂ stream by converting the volumetric flow of the CO₂ stream from operating conditions to standard conditions and then applying the density value for CO₂ at standard conditions and the measured concentration of CO₂ in the flow as a volume percent. First, we are specifying that, at the revised standard conditions, the density of CO₂ is 0.001868 metric tons per standard cubic meter. This is slightly different than the density value proposed (0.018704) as the result of additional research we have conducted. We are specifying that a reporter who applies the density value for CO₂ at standard conditions must use this specified value.

Second, we are revising the definitions of two of the input variables to Equation PP-2 in paragraph (a)(2).

Since it was finalized (74 FR 56260, October 30, 2009), Equation PP-2 allows a reporter to calculate annual mass of CO₂ with an input for CO₂ concentration in weight percent and an input for density of the CO₂ stream. So that reporters can avail themselves of the density value for CO₂ being finalized in this action, however, Equation PP-2 can now also be used to calculate annual mass of CO₂ with an input for CO₂ concentration in volume percent and an input for density of CO₂. We note that when we proposed this action, we did not propose to revise the definitions of the input variables because we erroneously overlooked the mismatch between the density value we were providing (CO₂) and the density value required by Equation PP-2 (the CO₂ stream). In order to provide all reporters with lower burden calculation procedures, as intended by proposing a density value for CO₂, we are correcting this omission and harmonizing Equation PP-2 with the finalized density value. We note that the revision to the two input variables is being applied for both reporters using flow meters and reporters using containers.

Third, we are amending 40 CFR 98.426(b)(3) and (b)(4) to require that for volumetric flow meters, the reporter must report quarterly concentration either in volume or weight percent and a density value for either CO₂ or the CO₂ stream, depending on which of the two equation input descriptions provided the reporter uses.

Fourth, we are amending language in 40 CFR 98.424(a)(5), (a)(5)(i) and (a)(5)(ii) to allow reporters to choose either a method published by a consensus-based standards organization or an industry standard practice to determine the density of the CO₂ stream. We are also replacing the word “measure” with the word “determine.” Previously, subpart PP required a reporter to use an appropriate method published by a consensus-based standards organization to measure density for CO₂ at standard conditions, if such a method existed. Only where no such method existed could an industry standard practice be used. However, we have been unable to identify any method published by a consensus-based standards organization for measuring the density of the CO₂ stream. Therefore, we are providing reporters with more flexibility on this requirement so that they can use an industry standard practice to calculate the density of the CO₂ stream rather than directly measure density with an instrument, if preferred.

Finally, we are amending the reference to the U.S. Food and Drug

Administration food-grade specifications for CO₂ in 40 CFR 98.424(b)(2) to correct a typographical error. The correct reference is 21 CFR 184.1240, not 21 CFR 184.1250.

Major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found in this preamble or the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA-HQ-OAR-2008-0508).

- We are adding a second aggregation equation (Equation PP-3b) with appropriate flow meter location requirements so that a reporter can select either the one-meter or two-meter approach for calculating total annual mass of CO₂.

- We are revising the definitions of two of the input variables to Equation PP-2 in paragraphs 40 CFR 98.423(a)(2) and (b)(2) so that the equation can be used to calculate annual mass of CO₂ with an input for CO₂ concentration in either volume percent and an input for density of CO₂, or weight percent CO₂ and the density of the whole stream.

2. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments were received on this subpart. Responses to additional significant comments received can be found in the document, “Response to Comments: Revision to Certain Provisions of the Mandatory Reporting of Greenhouse Gases Rule” (see EPA-HQ-OAR-2008-0508).

Comment: One commenter asserted that one of their facilities has already installed a CO₂ meter prior to purification, processing, or compression—as was required by 40 CFR 98.424 when Part 98 was finalized (74 FR 56260, October 30, 2009)—and because this facility has segregation, this results in a flow meter location prior to segregation. The commenter suggested that this facility and others like it should be allowed to keep their flow meters in place rather than be required to move them to a location after segregation, as was proposed in the amendments of August 11, 2010. The commenter suggested a two-meter approach, whereby a facility locates a main flow meter prior to segregation on the main, captured CO₂ stream and a subsequent flow meter after segregation on the diverted CO₂ stream and then calculates the CO₂ for off-site commercial use as the difference between the two. The commenter stated that this two-meter approach should be

equally acceptable to the approach proposed.

Response: EPA agrees that a reporter can calculate CO₂ supplied for commercial transaction or injection with sufficient accuracy with the two-meter approach suggested by the commenter, as long as the CO₂ stream diverted for on site use is the only CO₂ stream diversion after the location of the main flow meter. If any of the main CO₂ stream remaining after on-site diversion is further diverted (to a vent for emission, for example) then the difference between the captured CO₂ stream and the CO₂ stream diverted for on-site use will not be an accurate reflection of the CO₂ supplied for commercial transaction or injection. Therefore, EPA is finalizing two approaches for calculating CO₂ supplied, including aggregation equations with flow meter location requirements, so that a reporter can select either the one-meter or two-meter approach. However, we are specifying in the monitoring and QA/QC requirements (40 CFR 98.424) that a reporter may only follow the two-meter approach if the CO₂ stream(s) for on-site use is/are the only diversion(s) from the main, captured CO₂ stream after the main flow meter(s) location.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This action is not a “significant regulatory action” under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under the executive order.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. These amendments do not make substantive changes to the reporting requirements in any of the amended subparts. In many cases, the amendments to the reporting requirements reduce the reporting burden by making the reporting requirements conform more closely to current industry practices. While the final rule results in a net decrease in collection burden, there is a new reporting requirement for facilities with part 75 units. Previously, facilities with these units had the option of reporting biogenic CO₂ emissions separately. This final rule requires separate reporting of biogenic CO₂ emissions beginning in 2011; however facilities may use simplified methods based on available information. The Office of Management and Budget (OMB) has previously

approved the information collection requirements contained in the regulations promulgated on October 30, 2009, under 40 CFR part 98 under the provisions of the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0629. Burden is defined at 5 CFR 1320.3(b). 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.

Further information on EPA’s assessment on the impact on burden can be found in the Revisions Cost Memo (EPA–HQ–OAR–2008–0508).

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 these amendments on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration’s regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of these rule amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The rule amendments will not impose any new significant requirements on small entities that are not currently required by the rules promulgated on October 30, 2009 (*i.e.*, calculating and reporting annual GHG emissions).

Broadly, in developing the 2009 final rule EPA took several steps to reduce the impact on small entities. For example, EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, EPA did not require facilities to install CEMS if they did not already have them. Facilities without CEMS can calculate

emissions using readily available data or data that are less expensive to collect such as process data or material consumption data. For some source categories, EPA developed tiered methods that are simpler and less burdensome. Also, EPA required annual instead of more frequent reporting. Finally, EPA continues to conduct significant outreach on the mandatory GHG reporting rule and maintains an “open door” policy for stakeholders to help inform EPA’s understanding of key issues for the industries.

D. Unfunded Mandates Reform Act (UMRA)

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local or tribal governments or the private sector. In addition, EPA determined that the rule amendments contain no regulatory requirements that might significantly or uniquely affect small governments because the amendments will not impose any new requirements that are not currently required by the rule promulgated on October 30, 2009 (*i.e.*, calculating and reporting annual GHG emissions), and the rule amendments will not unfairly apply to small governments. Therefore, this action is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It 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 Executive Order 13132. However, for a more detailed discussion about how these rule amendments will relate to existing State programs, please see Section II of the preamble for the proposed GHG reporting rule (74 FR 16457 to 16461, April 10, 2009).

These amendments apply directly to facilities that supply fuel that when used emit greenhouse gases or facilities that directly emit greenhouse gases. They do not apply to governmental entities unless the government entity owns a facility that directly emits greenhouse gases above threshold levels (such as a landfill or stationary combustion source), so relatively few government facilities will be affected. This regulation also does not limit the

power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this action.

Although section 6 of Executive Order 13132 does not apply to this action, EPA did consult with State and local officials or representatives of State and local governments in developing the 2009 final rule. A summary of EPA's consultations with State and local governments is provided in Section VIII.E of the preamble to the 2009 final rule (74 FR 56260, October 30, 2009).

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The rule amendments will not result in any changes to the requirements of Part 98. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA sought opportunities to provide information to Tribal governments and representatives during the development of the rules promulgated on October 30, 2009. A summary of the EPA's consultations with Tribal officials is provided Sections VIII.E and VIII.F of the preamble to the final GHG Reporting Rule (74 FR 56260, October 30, 2009).

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

EPA interprets Executive Order 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 Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 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 subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

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 (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 the use of two new voluntary consensus standards from ASTM International. Specifically, EPA will allow facilities in the petroleum refining and petrochemical production industries to use ASTM D2593-93(2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, and ASTM D7633-10 Standard Test Method for Carbon Black—Carbon Content, in addition to the methods incorporated by reference in Part 98. These additional voluntary consensus standards will provide alternative method that owners or operators in these industries can use to monitor GHG emissions.

This rulemaking also involves the use of several standard methods that are in EPA publications. These include the following:

- Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminum Production (April 2008); IBR approved for 40 CFR 98.64(a).
- AP 42, Section 5.2, Transportation and Marketing of Petroleum Liquids, July 2008 (AP 42, Section 5.2); <http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf>; in Chapter 5, Petroleum Industry, of AP 42, Compilation of Air Pollutant Emission Factors, 5th Edition, Volume I; IBR approved for 40 CFR 98.253(n).
- AP 42, Section 7.1, Organic Liquid Storage Tanks, November 2006 (AP 42, Section 7.1), <http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf>; in Chapter 7, Liquid Storage Tanks, of AP 42, Compilation of Air Pollutant Emission Factors, 5th Edition, Volume 1; IBR approved for 40 CFR 98.243(m)(1) and 40 CFR 98.256(o)(2)(i).
- Method 8015C, Nonhalogenated Organics By Gas Chromatography, Revision 3, February 2007 (Method 8015C), <http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8015c.pdf>; in EPA Publication No. SW-846, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," Third Edition; IBR approved for 40 CFR 98.244(b)(4)(viii).

- Method 8021B, Aromatic And Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors, Revision 2, December 1996 (Method 8021B), <http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8021b.pdf>; in EPA Publication No. SW-846, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," Third Edition; IBR approved for 40 CFR 98.244(b)(4)(viii).

- Method 8031, Acrylonitrile By Gas Chromatography, Revision 0, September 1994 (Method 8031), <http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8031.pdf>; in EPA Publication No. SW-846, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," Third Edition; IBR approved for 40 CFR 98.244(b)(4)(viii).

- Method 9060A, Total Organic Carbon, Revision 1, November 2004 (Method 9060A), <http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/9060a.pdf>; in EPA Publication No. SW-846, "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," Third Edition; IBR approved for 40 CFR 98.244(b)(4)(viii).

These methods are being added by the final rule amendments as a result of working with affected industries to identify existing methods that can be used to provide the data needed to calculate GHG emissions, proposing the addition of the methods, and considering the public comments on the addition of the methods in the final rule making.

No new test methods were developed for this action.

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

Executive Order 12898 (59 FR 7629, February 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 Part 98 does 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 because it is a rule addressing

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 on December 31, 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: November 24, 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 98.3 is amended by:
 - a. Revising paragraphs (c)(1), (c)(4) introductory text, (c)(4)(i), (c)(4)(ii), and (c)(4)(iii) introductory text.
 - b. Adding paragraph (c)(4)(vi).
 - c. Adding a new sentence to the end of paragraph (c)(5)(i).
 - d. Adding paragraph (c)(12).
 - e. Revising the third sentence of paragraph (d)(3) introductory text.
 - f. Revising the first sentence of paragraph (f).
 - g. Revising paragraphs (g)(4) and (g)(5)(iii).
 - h. Revising paragraph (h).
 - i. Revising paragraph (i).
 - j. Adding paragraph (j).

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

* * * * *

(c) * * *

(1) Facility name or supplier name (as appropriate), and physical street address of the facility or supplier, including the city, State, and zip code.

* * * * *

(4) For facilities, except as otherwise provided in paragraph (c)(12) of this section, report annual emissions of CO₂, CH₄, N₂O, and each fluorinated GHG (as defined in § 98.6) as follows.

(i) Annual emissions (excluding biogenic CO₂) aggregated for all GHG from all applicable source categories, 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, expressed in metric tons.

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

* * * * *

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

(5) * * *

(i) * * * For fluorinated GHGs, calculate and report CO₂e for only those fluorinated GHGs listed in Table A–1 of this subpart.

* * * * *

(12) For the 2010 reporting year only, facilities that have "part 75 units" (*i.e.* units that are subject to subpart D of this part or units that use the methods in part 75 of this chapter to quantify CO₂ mass emissions in accordance with § 98.33(a)(5)) must report annual GHG emissions either in full accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section or in full accordance with paragraphs (c)(12)(i) through (c)(12)(iii) of this section. If the latter reporting option is chosen, you must report:

(i) Annual emissions aggregated for all GHG from all applicable source categories, expressed in metric tons of CO₂e calculated using Equation A–1 of this subpart. You must include biogenic CO₂ emissions from part 75 units in these annual emissions, but exclude biogenic CO₂ emissions from any non-part 75 units and other source categories.

(ii) Annual emissions of biogenic CO₂, expressed in metric tons (excluding biogenic CO₂ emissions from part 75 units), aggregated for all applicable source categories.

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

(A) Biogenic CO₂ (excluding biogenic CO₂ emissions from part 75 units).

(B) CO₂. You must include biogenic CO₂ emissions from part 75 units in these totals and exclude biogenic CO₂ emissions from other non-part 75 units and other source categories.

(C) CH₄.

(D) N₂O.

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

(d) * * *

(3) * * * An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2012.

* * *

(f) *Verification*. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(9) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. * * *

(g) * * *

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

(5) * * *

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

* * * * *

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

(2) The Administrator may notify the owner or operator in writing that an annual GHG report previously submitted by the owner or operator contains one or more substantive errors. Such notification will identify each such substantive error. The owner or

operator shall, within 45 days of receipt of the notification, either resubmit the report that, for each identified substantive error, corrects the identified substantive error (in accordance with the applicable requirements of this part) or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error.

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

(4) Notwithstanding paragraphs (h)(1) and (h)(2) of this section, upon request by the owner or operator, the Administrator may provide reasonable extensions of the 45-day period for submission of the revised report or information under paragraphs (h)(1) and (h)(2) of this section. If the Administrator receives a request for extension of the 45-day period, by e-mail to an address prescribed by the Administrator, at least two business days prior to the expiration of the 45-day period, and the Administrator does not respond to the request by the end of such period, the extension request is deemed to be automatically granted for 30 more days. During the automatic 30-day extension, the Administrator will determine what extension, if any, beyond the automatic extension is reasonable and will provide any such additional extension.

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

(i) *Calibration accuracy requirements.* The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the applicable flow meter calibration and accuracy requirements of this paragraph (i). The accuracy specifications in this paragraph (i) do not apply where either the use of company records (as defined in § 98.6) or the use of “best available

information” is specified in an applicable subpart of this part to quantify fuel usage and/or other parameters. Further, the provisions of this paragraph (i) do not apply to stationary fuel combustion units that use the methodologies in part 75 of this chapter to calculate CO₂ mass emissions.

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

(i) All flow meters and other measurement devices that are subject to the provisions of this paragraph (i) must

be calibrated according to one of the following: You may use the manufacturer's recommended procedures; an appropriate industry consensus standard method; or a method specified in a relevant subpart of this part. The calibration method(s) used shall be documented in the monitoring plan required under paragraph (g) of this section.

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

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

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

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

(2) Perform all flow meter calibration at measurement points that are representative of the normal operating range of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A-2 of this section. The terms “R” and “A” in Equation A-2 must be expressed in consistent units of measure (e.g., gallons/minute, ft³/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = \frac{|R - A|}{R} \times 100 \quad (\text{Eq. A-2})$$

Where:

CE = Calibration error (%).

R = Reference value.

A = Flow meter response to the reference value.

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration

of the differential pressure (delta-P), total pressure, and temperature transmitters.

(i) Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations.

Calculate the calibration error of each transmitter at each measurement point, using Equation A-3 of this subpart. The terms “R,” “A,” and “FS” in Equation A-3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each

measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the

calculated CE values for the three transmitters at each calibration level (*i.e.*, at the zero level and at each

upscale level) does not exceed 6.0 percent.

$$CE = \frac{|R - A|}{FS} \times 100 \quad (\text{Eq. A-3})$$

Where:

CE = Calibration error (%).

R = Reference value.

A = Transmitter response to the reference value.

FS = Full-scale value of the transmitter.

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

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

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

(C) You must document the methods used for the demonstration described in paragraph (i)(3)(ii)(A) of this section in the written GHG Monitoring Plan under

paragraph (g)(5)(i)(C) of this section.

You must also include the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations in the GHG Monitoring Plan. You must maintain all of this information in a format suitable for auditing and inspection.

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

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

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

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

industry consensus calibration schedule.

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

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

(j) *Measurement device installation—*

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

(2) *Requests for extension of the use of best available monitoring methods for measurement device installation.* The owner or operator must first provide the

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

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

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

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

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

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

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

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

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

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

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

(7) *One time extension past December 31, 2013.* If an owner or operator determines that a scheduled process equipment or unit shutdown will not occur by December 31, 2013, the owner or operator may re-apply to use best available monitoring methods for one additional time period, not to extend beyond December 31, 2015. To extend use of best available monitoring methods past December 31, 2013, the owner or operator must submit a new extension request by June 1, 2013 that contains the information required in paragraph (j)(4) of this section. The owner or operator must demonstrate to the Administrator's satisfaction that it continues to not be reasonably feasible to install the measurement device before December 31, 2013 without a process equipment or unit shutdown, or that installation of the measurement device could only be done through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. An owner or operator that submits a request under this paragraph to extend use of best available monitoring methods for measurement device installation must install all such devices by December 31, 2013, unless the extension request under this paragraph is approved by the Administrator.

■ 3. Section 98.4 is amended by revising paragraphs (i)(2) and (m)(2)(i) to read as follows:

§ 98.4 Authorization and responsibilities of the designated representative.

* * * * *

(i) * * *

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

* * * * *

(m) * * *

(2) * * *

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

* * * * *

■ 4. Section 98.6 is amended by:

■ a. Adding in alphabetical order definitions for "Agricultural by-products," "Primary fuel," "Solid by-products," "Used oil," and "Wood residuals."

■ b. Revising the definitions for "Bulk natural gas liquid or NGL," "Distillate Fuel Oil," "Fossil fuel," "Fuel gas," "Municipal solid waste or MSW," "Natural gas," "Natural gas liquids (NGLs)" and "Standard conditions or standard temperature and pressure (STP)."

■ c. Removing the definition for "Fossil fuel-fired."

§ 98.6 Definitions.

* * * * *

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

* * * * *

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

* * * * *

Distillate fuel oil means a classification for one of the petroleum

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

* * * * *

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

* * * * *

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

* * * * *

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

* * * * *

Natural gas means a naturally occurring mixture of hydrocarbon and

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

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

* * * * *

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

* * * * *

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

* * * * *

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

* * * * *

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

* * * * *

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

sludge from paper mills, trim, sander dust, and sawdust from wood products manufacturing (including resinated wood product residuals), and logging residues.

* * * * *

- 5. Section 98.7 is amended by:
- a. Removing and reserving paragraph (b).
- b. Revising paragraphs (d)(1) through (d)(10).
- c. Removing paragraph (d)(11).
- d. Revising paragraph (e)(4).
- e. Removing and reserving paragraph (e)(7).
- f. Revising paragraphs (e)(8), (e)(10), (e)(11), (e)(14) and (e)(15).
- g. Revising paragraphs (e)(19) and (e)(20).
- h. Revising paragraphs (e)(24) through (e)(27).
- i. Removing and reserving paragraph (e)(28).
- j. Revising paragraph (e)(30).
- k. Revising paragraph (e)(33).
- l. Revising paragraph (e)(36).
- m. Removing and reserving paragraph (e)(39).
- n. Adding paragraphs (e)(48) and (e)(49).
- o. Removing and reserving paragraph (f)(1).
- p. Revising paragraph (f)(2).
- q. Removing and reserving paragraph (g)(3).
- r. Revising paragraph (m)(3).
- s. Adding paragraphs (m)(8) through (m)(14).

§ 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 § 98.124(m)(1), § 98.324(e), § 98.354(d), § 98.354(h), § 98.344(c) and § 98.364(e).

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

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

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

(5) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 98.124(m)(5),

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

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

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

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

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

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

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

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

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

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

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

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

(19) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and

Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved for § 98.74(c) and § 98.164(b).

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

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

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

(26) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), and § 98.254(i).

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

(30) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for § 98.54(b), § 98.124(e)(2), § 98.224(b), and § 98.414(n).

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

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

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

(49) ASTM D7633-10 Standard Test Method for Carbon Black—Carbon

Content, approved May 15, 2010, IBR approved for § 98.244(b)(4)(xii).

* * * * *

(f) * * *
(1) [Reserved]

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

* * * * *

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

* * * * *

(8) Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminum Production (2008), <http://www.epa.gov/highwp/aluminum-pfc/documents/measureprotocol.pdf>, IBR approved for § 98.64(a).

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

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

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

(12) Method 8021B, Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors, Revision 2, December 1996 (Method 8021B), <http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8021b.pdf>; in EPA Publication No. SW-846, "Test Methods for Evaluating Solid

Waste, Physical/Chemical Methods,” Third Edition, IBR approved for § 98.244(b)(4)(viii).

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

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

■ 6. Table A–5 to subpart A of part 98 is amended by revising the entry for paragraph (B) under the heading “Natural gas and natural gas liquids suppliers (subpart NN)” to read as follows:

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

Supplier Categories ^a Applicable in 2010 and Future Years				
*	*	*	*	*
Natural gas and natural gas liquids suppliers (subpart NN)				
*	*	*	*	*
(B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.				
*	*	*	*	*

^aSuppliers are defined in each applicable subpart.

Subpart C—[Amended]

■ 7. Section 98.30 is amended by:

- a. Revising paragraph (b)(4).
- b. Revising paragraph (c) introductory text.
- c. Adding paragraph (d).

§ 98.30 Definition of the source category.

* * * * *

(b) * * *

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

* * * * *

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

* * * * *

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

■ 8. Section 98.32 is revised to read as follows:

§ 98.32 GHGs to report.

You must report CO₂, CH₄, and N₂O mass emissions from each stationary fuel combustion unit, except as otherwise indicated in this subpart.

■ 9. Section 98.33 is amended by:

- a. Revising paragraph (a) introductory text and paragraph (a)(1).
- b. Revising the definition of “HHV” in Equation C–2a of paragraph (a)(2)(i).
- c. Revising the first two sentences of paragraph (a)(2)(ii) introductory text.
- d. In paragraph (a)(2)(ii)(A), revising the first sentence and the definitions of “(HHV)_i,” “(Fuel)_i,” and “n” in Equation C–2b.

■ e. Revising paragraph (a)(2)(ii)(B).

■ f. Revising the definitions of “CC”, “MW”, and “MVC” in Equation C–5 of paragraph (a)(3)(iii).

■ g. Revising paragraphs (a)(3)(iv), (a)(3)(v), (a)(4)(iii), and (a)(4)(iv).

■ h. Adding paragraph (a)(4)(viii).

■ i. Revising paragraphs (a)(5) introductory text, (a)(5)(i) introductory text, (a)(5)(i)(A), (a)(5)(i)(B), (a)(5)(ii) introductory text, (a)(5)(ii)(A), (a)(5)(iii) introductory text, (a)(5)(iii)(A), and (a)(5)(iii)(B).

■ j. Redesignating paragraph (a)(5)(iii)(D) as paragraph (a)(5)(iv), and revising newly designated paragraph (a)(5)(iv).

■ k. Revising paragraph (b)(1)(iv).

■ l. Adding paragraphs (b)(1)(v), (b)(1)(vi) and (b)(1)(vii).

■ m. Revising paragraphs (b)(2)(ii), (b)(3)(ii)(A), (b)(3)(iii) introductory text, and (b)(3)(iii)(B).

■ n. Adding paragraph (b)(3)(iv).

■ o. Adding a second sentence to paragraph (b)(4)(i).

■ p. Revising paragraphs (b)(4)(ii)(A), (b)(4)(ii)(B), (b)(4)(ii)(E), (b)(4)(ii)(F), and (b)(4)(iii) introductory text.

■ q. Adding paragraph (b)(4)(iv).

■ r. Revising paragraph (b)(5) and the third sentence of paragraph (b)(6).

■ s. Revising paragraph (c)(1) introductory text and the definition of “HHV” in Equation C–8.

■ t. Adding paragraphs (c)(1)(i) and (c)(1)(ii).

■ u. Revising the second sentence of paragraph (c)(2).

■ v. In paragraph (c)(4) introductory text, revising the only sentence and revising the definition of “(HI)_A” in Equation C–10.

■ w. Revising paragraphs (c)(4)(i) and (c)(4)(ii).

■ x. Revising paragraph (c)(5).

■ y. Adding paragraph (c)(6).

■ z. In paragraph (d)(1), revising the first sentence, adding a second sentence, and revising the definition of “R” in Equation C–11.

■ aa. Revising paragraphs (d)(2), paragraph (e) introductory text, paragraph (e)(1), and paragraph (e)(2) introductory text.

■ bb. Revising the definition of “F_c” in Equation C–13 of paragraph (e)(2)(iii).

■ cc. Revising paragraphs (e)(2)(iv), (e)(2)(vi)(C), and (e)(3).

■ dd. Removing paragraph (e)(4).

■ ee. Redesignating paragraph (e)(5) as (e)(4).

■ ff. Revising the first sentence of newly designated paragraph (e)(4).

■ gg. Adding paragraph (e)(5).

§ 98.33 Calculating GHG emissions.

* * * * *

(a) *CO₂ emissions from fuel combustion.* Calculate CO₂ mass emissions by using one of the four calculation methodologies in paragraphs (a)(1) through (a)(4) of this section, subject to the applicable conditions, requirements, and restrictions set forth in paragraph (b) of this section. Alternatively, for units that meet the conditions of paragraph (a)(5) of this section, you may use CO₂ mass emissions calculation methods from part 75 of this chapter, as described in paragraph (a)(5) of this section. For units that combust both biomass and fossil fuels, you must calculate and report CO₂ emissions from the combustion of biomass separately using the methods in paragraph (e) of this section, except as otherwise provided in paragraphs (a)(5)(iv) and (e) of this section and in § 98.36(d).

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO₂ mass emissions for each type of fuel by using Equation C–1, C–1a, or C–1b of this section (as applicable).

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

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

Where:

CO₂ = Annual CO₂ mass emissions for the specific fuel type (metric tons).

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

for gaseous fuel, and volume in gallons for liquid fuel).

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

EF = Fuel-specific default CO₂ emission factor, from Table C-1 of this subpart (kg CO₂/mmBtu).

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

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

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

Where:

CO₂ = Annual CO₂ mass emissions from natural gas combustion (metric tons).

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

EF = Fuel-specific default CO₂ emission factor for natural gas, from Table C-1 of this subpart (kg CO₂/mmBtu).

0.1 = Conversion factor from therms to mmBtu

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

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

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

Where:

CO₂ = Annual CO₂ mass emissions from natural gas combustion (metric tons).

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

EF = Fuel-specific default CO₂ emission factor for natural gas, from Table C-1 of this subpart (kg CO₂/mmBtu).

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(2) * * *

(i) * * *

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

* * * * *

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

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

* * * * *

(HHV)_i = Measured high heat value of the fuel, for month “i” (which may be the arithmetic average of multiple determinations), or, if applicable, an

appropriate substitute data value (mmBtu per mass or volume).

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

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

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

* * * * *

(3) * * *

(iii) * * *

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

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

MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6

scf per kg mole if you select 60 °F as standard temperature.

* * * * *

(iv) Fuel flow meters that measure mass flow rates may be used for liquid or gaseous fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content. You must measure the density using one of the following appropriate methods. You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, <http://www.ansi.org>), the American Gas Association (AGA), 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002,

(713) 356–0060, <http://www.api.org>. The method(s) used shall be documented in the GHG Monitoring Plan required under § 98.3(g)(5).

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

* * * * *

(4) * * *

(iii) If the CO₂ concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content using a method described in § 75.11(b)(2) of this chapter or use an appropriate default moisture percentage. For coal, wood, and natural gas combustion, you may use the default

moisture values specified in § 75.11(b)(1) of this chapter.

Alternatively, for any type of fuel, you may determine an appropriate site-specific default moisture value (or values), using measurements made with EPA Method 4—Determination Of Moisture Content In Stack Gases, in appendix A–3 to part 60 of this chapter. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. If this option is selected, the site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. For each site-specific default moisture percentage, at least nine Method 4 runs

are required, except where the option to use moisture data from a RATA is selected, and the applicable regulation allows a single moisture determination to represent two or more RATA runs. In that case, you may base the site-specific moisture percentage on the number of moisture runs allowed by the RATA regulation. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value shall be updated whenever the owner or operator believes the current value is non-representative, due to changes in unit or process operation, but in any event no less frequently than annually. Use the updated moisture value in the subsequent CO₂ emissions calculations. For each unit operating hour, a moisture correction must be applied to Equation C–6 of this section as follows:

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

Where:

CO₂* = Hourly CO₂ mass emission rate, corrected for moisture (metric tons/hr).

CO₂ = Hourly CO₂ mass emission rate from Equation C–6 of this section, uncorrected (metric tons/hr).

%H₂O = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O₂) concentration monitor may be used in lieu of a CO₂ concentration monitor to determine the hourly CO₂ concentrations, in accordance with Equation F–14a or F–14b (as applicable) in appendix F to part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products (*i.e.*, no process CO₂ emissions or CO₂ emissions from sorbent are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter are combusted in the unit. If the O₂ monitoring option is selected, the F-factors used in Equations F–14a and F–14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter, as applicable. If Equation F–14b is used, the hourly moisture percentage in the stack gas shall be determined in accordance with paragraph (a)(4)(iii) of this section.

* * * * *

(viii) If a portion of the flue gases generated by a unit subject to Tier 4 (*e.g.*, a slip stream) is continuously diverted from the main flue gas exhaust system for the purpose of heat recovery

or some other similar process, and then exhausts through a stack that is not equipped with the continuous emission monitors to measure CO₂ mass emissions, CO₂ emissions shall be determined as follows:

(A) At least once a year, use EPA Methods 2 and 3A, and (if necessary) Method 4 in appendices A–2 and A–3 to part 60 of this chapter to perform emissions testing at a set point that best represents normal, stable process operating conditions. A minimum of three one-hour Method 3A tests are required, to determine the CO₂ concentration. A Method 2 test shall be performed during each Method 3A run, to determine the stack gas volumetric flow rate. If moisture correction is necessary, a Method 4 run shall also be performed during each Method 3A run. Important parametric information related to the stack gas flow rate (*e.g.*, damper positions, fan settings, *etc.*) shall also be recorded during the test.

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

Equation C–7 in paragraph (a)(4)(ii) of this section to make this correction; replace the word “Hourly” with the words “3-run average” in the equation nomenclature.

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

(D) If, for the majority of the operating hours during the year, the diverted stream is withdrawn at a steady rate at or near the tested set point (as evidenced by fan and damper settings and/or other parameters), you may use the calculated CO₂ mass emission rate from paragraph (a)(4)(viii)(B) of this section to estimate the CO₂ mass emissions for all operating hours in which flue gas is diverted from the main exhaust system. Otherwise, you must account for the variation in the flow rate of the diverted stream, as described in paragraph (c)(4)(viii)(E) of this section.

(E) If the flow rate of the diverted stream varies significantly throughout the year, except as provided below, repeat the stack test and emission rate calculation procedures described in paragraphs (c)(4)(viii)(A) and (c)(4)(viii)(B) of this section at a minimum of two more set points across the range of typical operating conditions to develop a correlation between CO₂ mass emission rate and the parametric data. If additional testing is not feasible, use the following approach to develop the necessary correlation. Assume that the average CO₂ concentration obtained in the annual stack test is the same at all operating set points. Then, beginning

with the measured flow rate from the stack test and the associated parametric data, perform an engineering analysis to estimate the stack gas flow rate at two or more additional set points. Calculate the CO₂ mass emission rate at each set point.

(F) Calculate the annual CO₂ mass emissions for the diverted stream as follows. For a steady-state process, multiply the number of hours in which flue gas was diverted from the main exhaust system by the CO₂ mass emission rate from the stack test. Otherwise, using the best available information and engineering judgment, apply the most representative CO₂ mass emission rate from the correlation in paragraph (c)(4)(viii)(E) of this section to determine the CO₂ mass emissions for each hour in which flue gas was diverted, and sum the results. To simplify the calculations, you may count partial operating hours as full hours.

(G) Finally, add the CO₂ mass emissions from paragraph (c)(4)(viii)(F) of this section to the annual CO₂ mass emissions measured by the CEMS at the main stack. Report this sum as the total annual CO₂ mass emissions for the unit.

(H) The exact method and procedures used to estimate the CO₂ mass emissions for the diverted portion of the flue gas exhaust stream shall be documented in the Monitoring Plan required under § 98.3(g)(5).

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

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to appendix D to part 75 of this chapter, but is not required by the applicable part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to part 75 of this chapter, together with Equation G-4 in appendix G to part 75 of this chapter to determine the hourly CO₂ mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO₂ mass emissions, respectively, in units of short tons; and

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to § 75.19 of this chapter but is not required by the applicable part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO₂ mass emissions, in units of short tons, using Equation LM-11 in § 75.19(c)(4)(iii) of this chapter.

* * * * *

(iii) For a unit that is not subject to subpart D of this part, uses flow rate and CO₂ (or O₂) CEMS to report heat input data year-round according to part 75 of this chapter, but is not required by the applicable part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to part 75 of this chapter to calculate the hourly CO₂ mass emission rates from the CEMS data. If an O₂ monitor is used, convert the hourly average O₂ readings to CO₂ using Equation F-14a or F-14b in appendix F to part 75 of this chapter (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO₂ mass emissions, respectively, in units of short tons.

* * * * *

(iv) For units that qualify to use the alternative CO₂ emissions calculation methods in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, if both biomass and fossil fuel are combusted during the year, separate calculation and reporting of the biogenic CO₂ mass emissions (as described in paragraph (e) of this section) is optional, only for the 2010 reporting year, as provided in § 98.3(c)(12).

(b) * * *

(1) * * *

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in § 98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used. This restriction does not apply to paragraphs (b)(1)(ii), (b)(1)(v), (b)(1)(vi), and (b)(1)(vii) of this section.

(v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms or mmBtu.

(vi) May be used for MSW combustion in a small, batch incinerator that burns no more than 1,000 tons per year of MSW.

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the unit's annual heat input is derived from those fuels, combined. Notwithstanding this requirement, if a unit combusts both MSW and tires and the reporter elects not to separately calculate and report biogenic CO₂ emissions from the combustion of tires, Tier 1 may be used for the MSW combustion, provided that no more than 10 percent of the unit's annual heat input is derived from MSW.

(2) * * *

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of natural gas and/or distillate fuel oil.

* * * * *

(3) * * *

(ii) * * *

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii), (b)(1)(v), and (b)(2)(ii) of this section.

* * * * *

(iii) Shall be used for a fuel not listed in Table C-1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to § 98.36(c)(3), in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr), provided that both of the following conditions apply:

* * * * *

(B) The fuel provides 10% or more of the annual heat input to the unit or, if § 98.36(c)(3) applies, to the group of units served by a common supply pipe.

(iv) Shall be used when specified in another applicable subpart of this part, regardless of unit size.

(4) * * *

(i) * * * Tier 4 may also be used for any group of stationary fuel combustion units, process units, or manufacturing units that share a common stack or duct.

(ii) * * *

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 600 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW as the primary fuel.

* * * * *

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified,

either in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 600 tons of MSW per day or less, if the unit meets all of the following three conditions:

* * * * *

(iv) May apply to common stack or duct configurations where:

(A) The combined effluent gas streams from two or more stationary fuel combustion units are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if all of the conditions in paragraph (b)(4)(iv)(A)(1) of this section or if the conditions in paragraph (b)(4)(iv)(A)(2) of this section are met.

(1) At least one of the units meets the requirements of paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(C) of this section, and the CEMS installed at the common stack (or duct) meet the requirements of paragraphs (b)(4)(ii)(D) through (b)(4)(ii)(F) of this section.

(2) At least one of the units and the monitors installed at the common stack or duct meet the requirements of paragraph (b)(4)(iii) of this section.

(B) The combined effluent gas streams from a process or manufacturing unit and a stationary fuel combustion unit are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if the combustion unit and the monitors installed at the

common stack or duct meet the applicability criteria specified in paragraph (b)(4)(iv)(A)(1), or (b)(4)(iv)(A)(2) of this section.

(C) The combined effluent gas streams from two or more manufacturing or process units are vented through a common stack or duct. In this case, if any of the units is required by an applicable subpart of this part to use Tier 4, the CO₂ mass emissions may be monitored at each individual unit, or the combined CO₂ mass emissions may be monitored at the common stack or duct. However, if it is not feasible to monitor the individual units, the combined CO₂ mass emissions shall be monitored at the common stack or duct.

(5) The Tier 4 Calculation Methodology shall be used:

(i) Starting on January 1, 2010, for a unit that is required to report CO₂ mass emissions beginning on that date, if all of the monitors needed to measure CO₂ mass emissions have been installed and certified by that date.

(ii) No later than January 1, 2011, for a unit that is required to report CO₂ mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO₂ mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010. However, if the required CEMS are certified some time in 2010, you need not wait until January 1, 2011 to begin using Tier 4. Rather, you may switch from Tier 2 or Tier 3 to Tier 4 as soon as CEMS certification testing is successfully completed. If this reporting option is chosen, you must document the change in CO₂ calculation methodology in the Monitoring Plan required under § 98.3(g)(5) and in the GHG emissions report under § 98.3(c). Data recorded by the CEMS during a certification test period in 2010 may be used for reporting under this part, provided that the following two conditions are met:

(A) The certification tests are passed in sequence, with no test failures.

(B) No unscheduled maintenance or repair of the CEMS is performed during the certification test period.

(iii) No later than 180 days following the date on which a change is made that triggers Tier 4 applicability under paragraph (b)(4)(ii) or (b)(4)(iii) of this section (e.g., a change in the primary fuel, manner of unit operation, or installed continuous monitoring equipment).

(6) * * * However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section, CO₂ emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) * * *

(1) Use Equation C-8 of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO₂, except when natural gas usage in units of therms or mmBtu is obtained from gas billing records. In that case, use Equation C-8a in paragraph (c)(1)(i) of this section or Equation C-8b in paragraph (c)(1)(ii) of this section (as applicable). For Equation C-8, use the same values for fuel consumption that you use for the Tier 1 or Tier 3 calculation.

* * * * *

HHV = Default high heat value of the fuel from Table C-1 of this subpart; alternatively, for Tier 3, if actual HHV data are available for the reporting year, you may average these data using the procedures specified in paragraph (a)(2)(ii) of this section, and use the average value in Equation C-8 (mmBtu per mass or volume).

* * * * *

(i) Use Equation C-8a to calculate CH₄ and N₂O emissions when natural gas usage is obtained from gas billing records in units of therms.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * 0.1 * EF$$

(Eq. C-8a)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of natural gas (metric tons).

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

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).

0.1 = Conversion factor from therms to mmBtu

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

(ii) Use Equation C-8b to calculate CH₄ and N₂O emissions when natural gas usage is obtained from gas billing records in units of mmBtu.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * EF$$

(Eq. C-8b)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of natural gas (metric tons).

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

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).

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

(2) * * * Use the same values for fuel consumption and HHV that you use for the Tier 2 calculation.

* * * * *

(4) Use Equation C-10 of this section for: units subject to subpart D of this part; units that qualify for and elect to use the alternative CO₂ mass emissions calculation methodologies described in paragraph (a)(5) of this section; and units that use the Tier 4 Calculation Methodology.

* * * * *

(HI)_A = Cumulative annual heat input from combustion of the fuel (mmBtu).

* * * * *

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH₄ or N₂O emissions. For units in the Acid Rain Program and units that report heat input data to EPA year-round according to part 75 of this chapter, obtain the cumulative annual heat input directly from the electronic data reports required under § 75.64 of this chapter. For Tier 4 units, use the best available information, as described in paragraph (c)(4)(ii)(C) of this section, to estimate the cumulative annual heat input (HI)_A.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, use Equation C-10 of this section separately for each type of fuel, except as provided in paragraph (c)(4)(ii)(B) of this section. Determine the appropriate values of (HI)_A as follows:

(A) For units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter, obtain (HI)_A for each type of fuel from the electronic data reports required under § 75.64 of this chapter, except as otherwise provided in paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(D) of this section.

(B) For a unit that uses CEMS to monitor hourly heat input according to part 75 of this chapter, the value of (HI)_A obtained from the electronic data reports under § 75.64 of this chapter may be attributed exclusively to the fuel with the highest F-factor, when the reporting option in 3.3.6.5 of appendix F to part 75 of this chapter is selected and implemented.

(C) For Tier 4 units, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the value of (HI)_A for each type of fuel. Instrumentation used to make these estimates is not subject to the

calibration requirements of § 98.3(i) or to the QA requirements of § 98.34.

(D) Units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter may use the best available information described in paragraph (c)(4)(ii)(C) of this section, to estimate (HI)_A for each fuel type, whenever fuel-specific heat input values cannot be directly obtained from the electronic data reports under § 75.64 of this chapter.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-8a, C-8b, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH₄ and N₂O emissions, in metric tons.

(6) Calculate the annual CH₄ and N₂O mass emissions from the combustion of blended fuels as follows:

(i) If the mass or volume of each component fuel in the blend is measured before the fuels are mixed and combusted, calculate and report CH₄ and N₂O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass or volume of each component fuel in the blend is not measured before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel "i" that is listed in Table C-2:

(A) Multiply (% Fuel)_i, the estimated mass or volume percentage (decimal fraction) of component fuel "i", by the total annual mass or volume of the blended fuel combusted during the reporting year, to obtain an estimate of the annual consumption of component "i";

(B) Multiply the result from paragraph (c)(6)(ii)(A) of this section by the HHV of the fuel (default value or, if available, the measured annual average value), to obtain an estimate of the annual heat input from component "i";

(C) Calculate the annual CH₄ and N₂O emissions from component "i", using Equation C-8, C-8a, C-8b, C-9a, or C-10 of this section, as applicable;

(D) Sum the annual CH₄ emissions across all component fuels to obtain the annual CH₄ emissions for the blend. Similarly sum the annual N₂O emissions across all component fuels to obtain the annual N₂O emissions for the blend. Report these annual emissions totals.

(d) * * *

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other

acid gas emission controls with sorbent injection to remove acid gases, if the chemical reaction between the acid gas and the sorbent produces CO₂ emissions, use Equation C-11 of this section to calculate the CO₂ emissions from the sorbent, except when those CO₂ emissions are monitored by CEMS. When a sorbent other than CaCO₃ is used, determine site-specific values of R and MW_S.

* * * * *

R = The number of moles of CO₂ released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is CaCO₃ and the targeted acid gas species is SO₂).

* * * * *

(2) The total annual CO₂ mass emissions reported for the unit shall include the CO₂ emissions from the combustion process and the CO₂ emissions from the sorbent.

(e) *Biogenic CO₂ emissions from combustion of biomass with other fuels.* Use the applicable procedures of this paragraph (e) to estimate biogenic CO₂ emissions from units that combust a combination of biomass and fossil fuels (i.e., either co-fired or blended fuels). Separate reporting of biogenic CO₂ emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in Table C-1 of this section and for municipal solid waste. In addition, when a biomass fuel that is not listed in Table C-1 is combusted in a unit that has a maximum rated heat input greater than 250 mmBtu/hr, if the biomass fuel accounts for 10% or more of the annual heat input to the unit, and if the unit does not use CEMS to quantify its annual CO₂ mass emissions, then, pursuant to § 98.33(b)(3)(iii), Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO₂ emissions from combustion of the fuel.

Notwithstanding these requirements, in accordance with § 98.3(c)(12), separate reporting of biogenic CO₂ emissions is optional for the 2010 reporting year for units subject to subpart D of this part and for units that use the CO₂ mass emissions calculation methodologies in part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic CO₂ emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used. Separate reporting of biogenic CO₂ emissions from the combustion of tires is also optional, but may be reported by following the provisions of paragraph (e)(3) of this section.

(1) You may use Equation C-1 of this subpart to calculate the annual CO₂ mass emissions from the combustion of the biomass fuels listed in Table C-1 of this subpart (except MSW and tires), in a unit of any size, including units equipped with a CO₂ CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under § 98.3(g):

(i) Company records.

(ii) The procedures in paragraph (e)(5) of this section.

(iii) The best available information for premixed fuels that contain biomass and fossil fuels (e.g., liquid fuel mixtures containing biodiesel).

(2) You may use the procedures of this paragraph if the following three conditions are met: First, a CO₂ CEMS (or a surrogate O₂ monitor) and a stack gas flow rate monitor are used to determine the annual CO₂ mass emissions (either according to part 75 of this chapter, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section); second, neither MSW nor tires is combusted in the unit during the reporting year; and third, the CO₂ emissions consist solely of combustion products (i.e., no process or sorbent emissions included).

* * * * *

(iii) * * *

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or a site-specific value determined under section 3.3.6 of appendix F to part 75 (scf CO₂/mmBtu).

* * * * *

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio} , the annual volume of CO₂ from the combustion of biomass.

* * * * *

(vi) * * *

(C) From the electronic data report required under § 75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO₂ mass emissions according to part 75 of this chapter. However, before calculating the annual biogenic CO₂ mass emissions, multiply the cumulative annual CO₂ mass emissions by 0.91 to convert from short tons to metric tons.

(3) You must use the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section to determine the annual biogenic CO₂ emissions from the

combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a CO₂ CEMS, and units for which optional separate reporting of biogenic CO₂ emissions from the combustion of tires is selected.

(i) Use an applicable CO₂ emissions calculation method in this section to quantify the total annual CO₂ mass emissions from the unit.

(ii) Determine the relative proportions of biogenic and non-biogenic CO₂ emissions in the flue gas on a quarterly basis using the method specified in § 98.34(d) (for units that combust MSW as the primary fuel or as the only fuel with a biogenic component) or in § 98.34(e) (for other units, including units that combust tires).

(iii) Determine the annual biogenic CO₂ mass emissions from the unit by multiplying the total annual CO₂ mass emissions by the annual average biogenic decimal fraction obtained from § 98.34(d) or § 98.34(e), as applicable.

(iv) If the combustion of MSW and/or tires provides no more than 10 percent of the annual heat input to a unit, or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW, you may estimate the annual biogenic CO₂ emissions as follows, in lieu of following the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section:

(A) Calculate the total annual CO₂ emissions from combustion of MSW and/or tires in the unit, using the Tier 1 calculation methodology in paragraph (a)(1) of this section.

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO₂ emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.20.

(4) If Equation C-1 or Equation C-2a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. * * *

(5) For units subject to subpart D of this part and for units that use the methods in part 75 of this chapter to quantify CO₂ mass emissions in accordance with paragraph (a)(5) of this section, you may calculate biogenic CO₂ emissions from the combustion of biomass fuels listed in Table C-1 of this subpart using Equation C-15a. This equation may not be used to calculate

biogenic CO₂ emissions from the combustion of tires or MSW; the methods described in paragraph (e)(3) of this section must be used for those fuels. Whenever $(HI)_A$, the annual heat input from combustion of biomass fuel in Equation C-15a, cannot be determined solely from the information in the electronic emissions reports under § 75.64 of this chapter (e.g., in cases where a unit uses CEMS in combination with multiple F-factors, a worst-case F-factor, or a prorated F-factor to report heat input rather than reporting heat input based on fuel type), use the best available information (as described in §§ 98.33(c)(4)(ii)(C) and (c)(4)(ii)(D)) to determine $(HI)_A$.

$$CO_2 = 0.001 * (HI)_A * EF \text{ (Eq. C-15a)}$$

Where:

CO_2 = Annual CO₂ mass emissions from the combustion of a particular type of biomass fuel listed in Table C-1 (metric tons)

$(HI)_A$ = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under § 75.64 of this chapter. Where this is not feasible use best available information, as described in §§ 98.33(c)(4)(ii)(C) and (c)(4)(ii)(D) (mmBtu)

EF = CO₂ emission factor for the biomass fuel, from Table C-1 (kg CO₂/mmBtu)
0.001 = Conversion factor from kg to metric tons

* * * * *

■ 10. Section 98.34 is amended by:

■ a. Revising paragraphs (a)(2), (a)(3), (a)(6), (b)(1) introductory text, (b)(1)(i), (b)(1)(ii), (b)(1)(iii), (b)(1)(vi), (b)(3)(ii), and (b)(3)(v).

■ b. Removing paragraph (b)(4).

■ c. Redesignating paragraph (b)(5) as (b)(4).

■ d. Revising newly designated paragraph (b)(4).

■ e. Revising paragraphs (c) introductory text, (c)(1)(i), (c)(1)(ii), (c)(2), (c)(3), and (c)(4).

■ f. Adding paragraphs (c)(6) and (c)(7).

■ g. Revising paragraphs (d), (e), (f) introductory text, (f)(1), (f)(3), (f)(5), and (f)(6).

■ h. Adding paragraphs (f)(7) and (f)(8).

■ i. Removing paragraph (g).

§ 98.34 Monitoring and QA/QC requirements.

* * * * *

(a) * * *

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel or fuel mixture (blend) is specified in this paragraph. When the specified frequency for a particular fuel or blend is based on a specified time period (e.g., week, month, quarter, or half-year), fuel sampling and analysis is

required only for those time periods in which the fuel or blend is combusted. The owner or operator may perform fuel sampling and analysis more often than the minimum required frequency, in order to obtain a more representative annual average HHV.

(i) For natural gas, semiannual sampling and analysis is required (*i.e.*, twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the unit's storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in-service tank on a given day (*e.g.*, from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (*e.g.*, ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, *etc.*). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot,

requiring only one representative sample, subject to the following conditions:

(A) For coal, the "type" of fuel means the rank of the coal (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the "type" of fuel means the grade number or classification of the oil (*e.g.*, No. 1 oil, No. 2 oil, kerosene, Jet A fuel, *etc.*).

(B) The owner or operator shall document in the monitoring plan under § 98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(iii) For liquid fuels other than fuel oil, and for gaseous fuels other than natural gas (including biogas), sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(v) For fuel blends that are received already mixed, or that are mixed on-site without measuring the exact amount of each component, as described in paragraph (a)(3)(ii) of this section, determine the HHV of the blend as follows. For blends of solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid or gaseous fuels, sampling and analysis is required at least once per calendar quarter. More frequent sampling is recommended if the composition of the blend varies significantly during the year.

(3) *Special considerations for blending of fuels.* In situations where different types of fuel listed in Table C-1 of this subpart (for example, different ranks of coal or different grades of fuel oil) are in the same state of matter (*i.e.*, solid, liquid, or gas), and are blended prior to combustion, use the following procedures to determine the appropriate CO₂ emission factor and HHV for the blend.

(i) If the fuels to be blended are received separately, and if the quantity

(mass or volume) of each fuel is measured before the fuels are mixed and combusted, then, for each component of the blend, calculate the CO₂ mass emissions separately. Substitute into Equation C-2a of this subpart the total measured mass or volume of the component fuel (from company records), together with the appropriate default CO₂ emission factor from Table C-1, and the annual average HHV, calculated according to § 98.33(a)(2)(ii). In this case, the fact that the fuels are blended prior to combustion is of no consequence.

(ii) If the fuel is received as a blend (*i.e.*, already mixed) or if the components are mixed on site without precisely measuring the mass or volume of each one individually, a reasonable estimate of the relative proportions of the components of the blend must be made, using the best available information (*e.g.*, the approximate annual average mass or volume percentage of each fuel, based on the typical or expected range of values). Determine the appropriate CO₂ emission factor and HHV for use in Equation C-2a of this subpart, as follows:

(A) Consider the blend to be the "fuel type," measure its HHV at the frequency prescribed in paragraph (a)(2)(v) of this section, and determine the annual average HHV value for the blend according to § 98.33(a)(2)(ii).

(B) Calculate a heat-weighted CO₂ emission factor, (EF)_B, for the blend, using Equation C-16 of this section. The heat-weighting in Equation C-16 is provided by the default HHVs (from Table C-1) and the estimated mass or volume percentages of the components of the blend.

(C) Substitute into Equation C-2a of this subpart, the annual average HHV for the blend (from paragraph (a)(3)(ii)(A) of this section) and the calculated value of (EF)_B, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO₂ mass emissions from combustion of the blend.

$$(EF)_B = \frac{\sum_{i=1}^n [(HHV)_i (\%Fuel)_i (EF)_i]}{(HHV)_B}$$

(Eq. C-16)

Where:

(EF)_B = Heat-weighted CO₂ emission factor for the blend (kg CO₂/mmBtu)

(HHV)_i = Default high heat value for fuel "i" in the blend, from Table C-1 (mmBtu per mass or volume)

(%Fuel)_i = Estimated mass or volume percentage of fuel "i" (mass % or volume

%, as applicable, expressed as a decimal fraction; *e.g.*, 25% = 0.25)

(EF)_i = Default CO₂ emission factor for fuel "i" from Table C-1 (mmBtu per mass or volume)

(HHV)_B = Annual average high heat value for the blend, calculated according to § 98.33(a)(2)(ii) (mmBtu per mass or volume)

(iii) Note that for the case described in paragraph (a)(3)(ii) of this section, if measured HHV values for the individual fuels in the blend or for the blend itself are not routinely received at the minimum frequency prescribed in

paragraph (a)(2) of this section (or at a greater frequency), and if the unit qualifies to use Tier 1, calculate (HHV)_B^{*}, the heat-weighted default HHV for the blend, using Equation C-17 of this section. Then, use Equation C-16 of this section, replacing the term (HHV)_B with (HHV)_B^{*} in the denominator, to determine the heat-

weighted CO₂ emission factor for the blend. Finally, substitute into Equation C-1 of this subpart, the calculated values of (HHV)_B^{*} and (EF)_B, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO₂ mass emissions from combustion of the blend.

$$HHV_B^* = \sum_{i=1}^n [(HHV)_i (\%Fuel)_i]$$

(Eq. C-17)

Where:

(HHV)_B^{*} = Heat-weighted default high heat value for the blend (mmBtu per mass or Volume)

(HHV)_i = Default high heat value for fuel “i” in the blend, from Table C-1 (mmBtu per mass or volume)

(%Fuel)_i = Estimated mass or volume percentage of fuel “i” in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

(iv) If the fuel blend described in paragraph (a)(3)(ii) of this section consists of a mixture of fuel(s) listed in Table C-1 of this subpart and one or more fuels not listed in Table C-1, calculate CO₂ and other GHG emissions only for the Table C-1 fuel(s), using the best available estimate of the mass or volume percentage(s) of the Table C-1 fuel(s) in the blend. In this case, Tier 1 shall be used, with the following modifications to Equations C-17 and C-1, to account for the fact that not all of the fuels in the blend are listed in Table C-1:

(A) In Equation C-17, apply the term (Fuel)_i only to the Table C-1 fuels. For each Table C-1 fuel, (Fuel)_i will be the estimated mass or volume percentage of the fuel in the blend, divided by the sum of the mass or volume percentages of the Table C-1 fuels. For example, suppose that a blend consists of two Table C-1 fuels (“A” and “B”) and one fuel type (“C”) not listed in the Table, and that the volume percentages of fuels A, B, and C in the blend, expressed as decimal fractions, are, respectively, 0.50, 0.30, and 0.20. The term (Fuel)_i in Equation C-17 for fuel A will be 0.50/(0.50 + 0.30) = 0.625, and for fuel B, (Fuel)_i will be 0.30/(0.50 + 0.30) = 0.375.

(B) In Equation C-1, the term “Fuel” will be equal to the total mass or volume of the blended fuel combusted during the year multiplied by the sum of the mass or volume percentages of the Table C-1 fuels in the blend. For the example in paragraph (a)(3)(iv)(A) of this section,

“Fuel” = (Annual volume of the blend combusted)(0.80).

* * * * *

(6) You must use one of the following appropriate fuel sampling and analysis methods. The HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the high heat values. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.api.org>). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(b) * * *

(1) You must calibrate each oil and gas flow meter according to § 98.3(i) and the provisions of this paragraph (b)(1).

(i) Perform calibrations using any of the test methods and procedures in this

paragraph (b)(1)(i). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(A) You may use the calibration procedures specified by the flow meter manufacturer.

(B) You may use an appropriate flow meter calibration method published by a consensus-based standards organization, if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.api.org>).

(C) You may use an industry-accepted practice.

(ii) In addition to the initial calibration required by § 98.3(i), recalibrate each fuel flow meter (except as otherwise provided in paragraph (b)(1)(iii) of this section) according to one of the following. You may recalibrate annually, at the minimum frequency specified by the manufacturer, or at the interval specified by industry standard practice.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recordkeeping

requirements of §§ 98.3(g)(5)(i)(C), (g)(6), and (g)(7), provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Meters used exclusively to measure the flow rates of fuels that are only used for unit startup are also exempted from the initial and ongoing calibration requirements of this paragraph.

* * * * *

(vi) If a mixture of liquid or gaseous fuels is transported by a common pipe, you may either separately meter each of the fuels prior to mixing, using flow meters calibrated according to § 98.3(i), or consider the fuel mixture to be the “fuel type” and meter the mixed fuel, using a flow meter calibrated according to § 98.3(i).

* * * * *

(3) * * *

(ii) For each type of fuel, the minimum required frequency for collecting and analyzing samples for carbon content and (if applicable) molecular weight is specified in this paragraph. When the sampling frequency is based on a specified time period (e.g., week, month, quarter, or half-year), fuel sampling and analysis is required for only those time periods in which the fuel is combusted.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in service

tank on a given day (e.g., from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

(1) For coal, the “type” of fuel means the rank of the coal (i.e., anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the “type” of fuel means the grade number or classification of the oil (e.g., No. 1 oil, No. 2 oil, kerosene, Jet A fuel, etc.).

(2) The owner or operator shall document in the monitoring plan under § 98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(C) For liquid fuels other than fuel oil and for biogas, sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., process gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment, such as a gas chromatograph, is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(F) For mixtures (blends) of solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid fuels, and for gas mixtures consisting only of natural gas and biogas, sampling and analysis is required at least once per calendar quarter. For gas mixtures that contain gases other than natural gas (including biogas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

* * * * *

(v) To calculate the CO₂ mass emissions from combustion of a blend of

fuels in the same state of matter (solid, liquid, or gas), you may either:

(A) Apply Equation C–3, C–4 or C–5 of this subpart (as applicable) to each component of the blend, if the mass or volume, the carbon content, and (if applicable), the molecular weight of each component are accurately measured prior to blending; or

(B) Consider the blend to be the “fuel type.” Then, at the frequency specified in paragraph (b)(3)(ii)(F) of this section, measure the carbon content and, if applicable, the molecular weight of the blend and calculate the annual average value of each parameter in the manner described in § 98.33(a)(2)(ii). Also measure the mass or volume of the blended fuel combusted during the reporting year. Substitute these measured values into Equation C–3, C–4, or C–5 of this subpart (as applicable).

(4) You must use one of the following appropriate fuel sampling and analysis methods. The results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions.

Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, <http://www.api.org>). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(c) For the Tier 4 Calculation Methodology, the CO₂, flow rate, and (if applicable) moisture monitors must be

certified prior to the applicable deadline specified in § 98.33(b)(5).

(1) * * *
(i) §§ 75.20(c)(2), (c)(4), and (c)(5) through (c)(7) of this chapter and appendix A to part 75 of this chapter.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 of this chapter (for the CO₂ concentration monitor) and Performance Specification 6 in appendix B to part 60 of this chapter (for the continuous emission rate monitoring system (CERMS)).

* * * * *

(2) If an O₂ concentration monitor is used to determine CO₂ concentrations, the applicable provisions of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO₂ basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to part 60 of this chapter is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO₂ monitor (or surrogate O₂ monitor) and the flow rate monitor, conduct cylinder gas audits of the CO₂ concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO₂ concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

* * * * *

(6) For certain applications where combined process emissions and combustion emissions are measured, the CO₂ concentrations in the flue gas may be considerably higher than for combustion emissions alone. In such cases, the span of the CO₂ monitor may, if necessary, be set higher than the specified levels in the applicable regulations. If the CO₂ span value is set higher than 20 percent CO₂, the cylinder gas audits of the CO₂ monitor under appendix F to part 60 of this chapter

may be performed at 40 to 60 percent and 80 to 100 percent of span, in lieu of the prescribed calibration levels of 5 to 8 percent CO₂ and 10 to 14 percent CO₂.

(7) Hourly average data from the CEMS shall be validated in a manner consistent with one of the following: §§ 60.13(h)(2)(i) through (h)(2)(vi) of this chapter; § 75.10(d)(1) of this chapter; or the hourly data validation requirements of an applicable State CEM regulation.

(d) Except as otherwise provided in § 98.33 (b)(1)(vi) and (b)(1)(vii), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO₂ emissions using ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see § 98.7) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see § 98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ± 5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (e.g., 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO₂ emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic

emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO₂ is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, e.g., tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866–08 (incorporated by reference, see § 98.7) and ASTM D7459–08 (incorporated by reference, see § 98.7) may be used to determine the biogenic portion of the CO₂ emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(f) The records required under § 98.33(g)(2)(i) shall include an explanation of how the following parameters are determined from company records (or, if applicable, from the best available information):

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used, including cases where § 98.36(c)(4) applies.

* * * * *

(3) Fossil fuel consumption when § 98.33(e)(2) applies to a unit that uses CEMS to quantify CO₂ emissions and that combusts both fossil and biomass fuels.

* * * * *

(5) Quantity of steam generated by a unit when § 98.33(a)(2)(iii) applies.

(6) Biogenic fuel consumption and high heating value, as applicable, under §§ 98.33(e)(5) and (e)(6).

(7) Fuel usage for CH₄ and N₂O emissions calculations under § 98.33(c)(4)(ii).

(8) Mass of biomass combusted, for premixed fuels that contain biomass and fossil fuels under § 98.33(e)(1)(iii).

■ 11. Section 98.35 is amended by revising paragraph (a) to read as follows:

§ 98.35 Procedures for estimating missing data.

* * * * *

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data year-round in

accordance with part 75 of this chapter, the missing data substitution procedures in part 75 of this chapter shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

* * * * *

■ 12. Section 98.36 is amended by:

- a. Revising paragraph (b)(5).
- b. Removing paragraphs (b)(9) and (b)(10).
- c. Redesignating paragraphs (b)(6) through (b)(8) as paragraphs (b)(8) through (b)(10), respectively.
- d. Revising newly designated paragraphs (b)(8) and (b)(9).
- e. Adding new paragraphs (b)(6) and (b)(7).
- f. Removing and reserving paragraphs (c)(1)(ii) and (c)(1)(iii).
- g. Revising paragraphs (c)(1)(vi) and (c)(1)(vii).
- h. Redesignating paragraph (c)(1)(viii) as paragraph (c)(1)(x), and revising newly designated paragraph (c)(1)(x).
- i. Removing paragraph (c)(1)(ix).
- j. Adding new paragraphs (c)(1)(viii) and (c)(1)(ix).
- k. Revising paragraphs (c)(2) introductory text, (c)(2)(ii), (c)(2)(iii), and (c)(2)(v).
- l. Removing paragraph (c)(2)(viii).
- m. Redesignating paragraphs (c)(2)(vi) and (c)(2)(vii) as paragraphs (c)(2)(viii) and (c)(2)(ix), and revising newly designated paragraphs (c)(2)(viii) and (c)(2)(ix).
- n. Adding new paragraphs (c)(2)(vi) and (c)(2)(vii).
- o. Removing and reserving paragraph (c)(3)(ii).
- p. Revising paragraphs (c)(3) introductory text, (c)(3)(iii), and (c)(3)(vii).
- q. Removing paragraph (c)(3)(viii).
- r. Adding new paragraphs (c)(3)(viii), (c)(3)(ix), and (c)(4).
- s. Revising paragraph (d).
- t. Revising paragraphs (e)(1)(iii), (e)(2)(i), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iii), (e)(2)(iv)(A), and (e)(2)(iv)(C).
- u. Adding paragraphs (e)(2)(iv)(F) and (e)(2)(iv)(G).
- v. Revising paragraph (e)(2)(v)(C).
- w. Adding paragraph (e)(2)(v)(E).
- x. Revising paragraphs (e)(2)(vii)(A), (e)(2)(ix) introductory text, and (e)(2)(x) introductory text.
- y. Removing paragraphs (e)(2)(x)(B) and (e)(2)(x)(C).
- z. Redesignating paragraph (e)(2)(x)(D) as (e)(2)(x)(B), and revising newly designated paragraph (e)(2)(x)(B).
- aa. Revising paragraph (e)(2)(xi).

§ 98.36 Data reporting requirements.

* * * * *

(b) * * *

(5) The methodology (*i.e.*, tier) used to calculate the CO₂ emissions for each type of fuel combusted (*i.e.*, Tier 1, 2, 3, or 4).

(6) The methodology start date, for each fuel type.

(7) The methodology end date, for each fuel type.

(8) For a unit that uses Tiers 1, 2, or 3:

(i) The annual CO₂ mass emissions (including biogenic CO₂), and the annual CH₄, and N₂O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO₂e; and

(ii) Metric tons of biogenic CO₂ emissions (if applicable).

(9) For a unit that uses Tier 4:

(i) If the total annual CO₂ mass emissions measured by the CEMS consists entirely of non-biogenic CO₂ (*i.e.*, CO₂ from fossil fuel combustion plus, if applicable, CO₂ from sorbent and/or process CO₂), report the total annual CO₂ mass emissions, expressed in metric tons. You are not required to report the combustion CO₂ emissions by fuel type.

(ii) Report the total annual CO₂ mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO₂, separately report the annual non-biogenic CO₂ mass emissions and the annual CO₂ mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO₂ emissions by fuel type.

(iii) An estimate of the heat input from each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year, and the annual CH₄ and N₂O emissions for each of these fuels, expressed in metric tons of each gas and in metric tons of CO₂e.

* * * * *

(c) * * *

(1) * * *

(ii) [Reserved]

(iii) [Reserved]

* * * * *

(vi) Annual CO₂ mass emissions and annual CH₄, and N₂O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO₂e. If any of the units burn both fossil fuels and biomass, report also the annual CO₂ emissions from combustion of all fossil fuels combined and annual CO₂ emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The methodology (*i.e.*, tier) used to calculate the CO₂ mass emissions for

each type of fuel combusted in the units (*i.e.*, Tier 1, Tier 2, or Tier 3).

(viii) The methodology start date, for each fuel type.

(ix) The methodology end date, for each fuel type.

(x) The calculated CO₂ mass emissions (if any) from sorbent expressed in metric tons.

(2) *Monitored common stack or duct configurations.* When the flue gases from two or more stationary fuel combustion units at a facility are combined together in a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO₂ mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. This monitoring and reporting alternative may also be used when process off-gases or a mixture of combustion products and process gases are combined together in a common stack or duct before exiting to the atmosphere. Whenever the common stack or duct monitoring option is applied, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(ii) Number of units sharing the common stack or duct. Report "1" when the flue gas flowing through the common stack or duct includes combustion products and/or process off-gases, and all of the effluent comes from a single unit (*e.g.*, a furnace, kiln, petrochemical production unit, or smelter).

(iii) Combined maximum rated heat input capacity of the units sharing the common stack or duct (mmBtu/hr). This data element is required only when all of the units sharing the common stack are stationary fuel combustion units.

* * * * *

(v) The methodology (tier) used to calculate the CO₂ mass emissions, *i.e.*, Tier 4.

(vi) The methodology start date.

(vii) The methodology end date.

(viii) Total annual CO₂ mass emissions measured by the CEMS, expressed in metric tons. If any of the units burn both fossil fuels and biomass, separately report the annual non-biogenic CO₂ mass emissions (*i.e.*, CO₂ from fossil fuel combustion plus, if applicable, CO₂ from sorbent and/or process CO₂) and the annual CO₂ mass emissions from biomass combustion, each expressed in metric tons.

(ix) An estimate of the heat input from each type of fuel listed in Table C-2 of

this subpart that was combusted during the report year in the units sharing the common stack or duct during the report year, and, for each of these fuels, the annual CH₄ and N₂O mass emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO₂e.

(3) *Common pipe configurations.*

When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with § 98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO₂ mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with § 98.33(b)(2)(ii). As a second example,

in accordance with § 98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms. When the common pipe reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(iii) The highest maximum rated heat input capacity of any unit served by the common pipe (mmBtu/hr).

* * * * *

(vii) Annual CO₂ mass emissions and annual CH₄ and N₂O emissions from each fuel type for the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO₂e.

(viii) Methodology start date

(ix) Methodology end date

(4) The following alternative reporting option applies to facilities at which a common liquid or gaseous fuel supply is shared between one or more large combustion units, such as boilers or combustion turbines (including units subject to subpart D of this part and other units subject to part 75 of this chapter) and small combustion sources, including, but not limited to, space heaters, hot water heaters, and lab burners. In this case, you may simplify reporting by attributing all of the GHG emissions from combustion of the shared fuel to the large combustion unit(s), provided that:

(i) The total quantity of the fuel combusted during the report year in the units sharing the fuel supply is measured, either at the "gate" to the facility or at a point inside the facility, using a fuel flow meter, billing meter, or tank drop measurements (as applicable);

(ii) On an annual basis, at least 95 percent (by mass or volume) of the shared fuel is combusted in the large combustion unit(s), and the remainder is combusted in the small combustion sources. Company records may be used to determine the percentage distribution of the shared fuel to the large and small units; and

(iii) The use of this reporting option is documented in the Monitoring Plan required under § 98.3(g)(5). Indicate in the Monitoring Plan which units share the common fuel supply and the method used to demonstrate that this alternative reporting option applies. For the small combustion sources, a description of the types of units and the approximate number of units is sufficient.

(d) *Units subject to part 75 of this chapter.*

(1) For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (*e.g.*, 1, 2, CS001, MS1A, CP001, *etc.*) that are reported under § 75.64 of this chapter.

(ii) Annual CO₂ emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO₂ emissions under § 98.3(c)(4)(ii) and § 98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in § 98.3(c)(12).

(iii) Annual CH₄ and N₂O emissions at each monitored location, for each fuel type listed in Table C-2 that was combusted during the year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in metric tons of CO₂e.

(iv) The total heat input from each fuel listed in Table C-2 that was combusted during the year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in mmBtu.

(v) Identification of the Part 75 methodology used to determine the CO₂ mass emissions.

(vi) Methodology start date.

(vii) Methodology end date.

(viii) Acid Rain Program indicator.

(ix) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons of CO₂e, except where the reporting provisions of §§ 98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(2) For units that use the alternative CO₂ mass emissions calculation methods provided in § 98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (*e.g.*, 1, 2, CS001, MS1A, CP001, *etc.*) that are reported under § 75.64 of this chapter.

(ii) For units that use the alternative methods specified in § 98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to part 75 of this chapter or § 75.19 of this chapter:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO₂ mass emissions for each fuel type.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate whether heat input is calculated according to appendix D to part 75 of this chapter or § 75.19 of this chapter.

(F) Annual CO₂ emissions at each monitored location, across all fuel types, expressed in metric tons of CO₂e.

(G) Annual heat input from each type of fuel listed in Table C-2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH₄ and N₂O emissions at each monitored location, from each fuel type listed in Table C-2 of this subpart that was combusted during the reporting year (except as otherwise provided in § 98.33(c)(4)(ii)(D)), expressed in metric tons CO₂e.

(I) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons CO₂e, except where the reporting provisions of §§ 98.33(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in § 98.33(a)(5)(iii) to monitor heat input year-round according to part 75 of this chapter:

(A) Each type of fuel combusted during the reporting year.

(B) Methodology used to calculate the CO₂ mass emissions.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(F) The total annual CO₂ emissions at each monitored location, expressed in metric tons of CO₂e.

(G) Annual heat input from each type of fuel listed in Table C-2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH₄ and N₂O emissions at each monitored location, from each fuel type listed in Table C-2 of this subpart that was combusted during the reporting year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in metric tons CO₂e.

(I) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons CO₂e, except where the reporting provisions of §§ 98.33(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(e) * * *

(1) * * *

(iii) Are not in the Acid Rain Program, but are required to monitor and report CO₂ mass emissions and heat input data year-round, in accordance with part 75 of this chapter.

(2) * * *

(i) For the Tier 1 Calculation Methodology, report the total quantity

of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels, or, if applicable, therms or mmBtu for natural gas.

(ii) * * *

(C) The high heat values used in the CO₂ emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report a HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month. Indicate whether each reported HHV is a measured value or a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO₂ mass emissions, report the total quantity (*i.e.*, pounds) of steam produced from MSW or solid fuel combustion during each month of the reporting year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for HHV are received.

(iv) * * *

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during each month of the reporting year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

* * * * *

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). For each calendar month of the reporting year in which carbon content and, if applicable, molecular weight determination is required, report a value of each parameter. If multiple values of a parameter are obtained in a given month, report the arithmetic average value for the month. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

* * * * *

(F) The annual average HHV, when measured HHV data, rather than a

default HHV from Table C-1 of this subpart, are used to calculate CH₄ and N₂O emissions for a Tier 3 unit, in accordance with § 98.33(c)(1).

(G) The value of the molar volume constant (MVC) used in Equation C-5 (if applicable).

(v) * * *

(C) The methods used to determine the carbon content and (if applicable) the molecular weight of each type of fuel combusted.

* * * * *

(E) The date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for carbon content and (if applicable) molecular weight are received.

* * * * *

(vii) * * *

(A) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program were used.

* * * * *

(ix) For units that combust both fossil fuel and biomass, when biogenic CO₂ is determined according to § 98.33(e)(2), you shall report the following additional information, as applicable:

* * * * *

(x) When ASTM methods D7459-08 (incorporated by reference, see § 98.7) and D6866-08 (incorporated by reference, see § 98.7) are used to determine the biogenic portion of the annual CO₂ emissions from MSW combustion, as described in § 98.34(d), report:

* * * * *

(B) The annual biogenic CO₂ mass emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 (incorporated by reference, see § 98.7) and D6866-08 (incorporated by reference, see § 98.7) are used in accordance with § 98.34(e) to determine the biogenic portion of the annual CO₂ emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires if you are electing to report biogenic CO₂ emissions from tire combustion) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (*e.g.*, if the biogenic fraction of the CO₂ emissions is 30 percent, report 0.30).

* * * * *

■ 13. Table C-1 to Subpart C is amended by:

- a. Revising the heading.
- b. Removing the entry for “Pipeline (Weighted U.S. Average)” and adding an entry for “(Weighted U.S. Average)” in its place.
- c. Removing the entry for “Still Gas.”
- d. Adding an entry for “Used Oil”, following the entry for “Residual Fuel Oil No. 6.”
- e. Revising the entry for “Ethane”.
- f. Adding an entry for “Ethanol”, following the entry for “Ethane.”

- g. Revising the phrase “Fossil fuel-derived fuels (solid)” to read “Other fuels-solid.”
- h. Revising the entry for “Municipal Solid Waste.”
- i. Adding entries for “Plastics” and “Petroleum Coke”, following the entry for “Tires.”
- j. Revising the phrase “Fossil fuel-derived fuels (gaseous)” to read “Other fuels—gaseous.”

- k. Adding entries for “Propane Gas” and “Fuel Gas,” following the entry for “Coke Oven Gas.”
- l. Amending the entry for “Biomass fuels—liquid” by centering “Biomass fuels—liquid.”
- m. Revising the entries for “Ethanol” and “Biodiesel” that follow the entry for “Biomass fuels—liquid.”
- n. Revising footnote “1.”
- o. Adding footnote “2.”

TABLE C–1 TO SUBPART C—DEFAULT CO₂ EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO ₂ emission factor
(Weighted U.S. Average)	1.028×10^{-3}	53.02
Used Oil	0.135	74.00
Ethane	0.069	62.64
Ethanol	0.084	68.44
Other fuels (solid)	mmBtu/short ton	kg CO ₂ /mmBtu
Municipal Solid Waste	9.95 ¹	90.7
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
Other fuels (gaseous)	mmBtu/scf	kg CO ₂ /mmBtu
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas ²	1.388×10^{-3}	59.00
Ethanol	0.084	68.44
Biodiesel	0.128	73.84

¹ Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

² Reporters subject to subpart X of this part that are complying with § 98.243(d) or subpart Y of this part may only use the default HHV and the default CO₂ emission factor for fuel gas combustion under the conditions prescribed in § 98.243(d)(2)(i) and (d)(2)(ii) and § 98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C–5) or Tier 4.

- 14. The first Table C–2 to Subpart C is removed, and the second Table C–2 to Subpart C is revised to read as follows:

TABLE C–2 TO SUBPART C—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}

TABLE C-2 TO SUBPART C—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1g of CH₄/mmBtu.

Subpart D—[Amended]

- 15. Section 98.40 is amended by revising paragraph (a) to read as follows:

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO₂ mass emissions year-round according to 40 CFR part 75.

* * * * *

- 16. Section 98.43 is revised to read as follows:

§ 98.43 Calculating GHG emissions.

(a) Except as provided in paragraph (b) of this section, continue to monitor and report CO₂ mass emissions as required under § 75.13 or section 2.3 of appendix G to 40 CFR part 75, and § 75.64. Calculate CO₂, CH₄, and N₂O emissions as follows:

(1) Convert the cumulative annual CO₂ mass emissions reported in the fourth quarter electronic data report required under § 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(2) Calculate and report annual CH₄ and N₂O mass emissions under this subpart by following the applicable method specified in § 98.33(c).

(b) Calculate and report biogenic CO₂ emissions under this subpart by following the applicable methods specified in § 98.33(e). The CO₂ emissions (excluding biogenic CO₂) for units subject to this subpart that are reported under §§ 98.3(c)(4)(i) and (c)(4)(iii)(B) shall be calculated by subtracting the biogenic CO₂ mass emissions calculated according to § 98.33(e) from the cumulative annual CO₂ mass emissions from paragraph (a)(1) of this section. Separate calculation and reporting of biogenic CO₂ emissions is optional only for the 2010 reporting year pursuant to § 98.3(c)(12) and required every year thereafter.

- 17. Section 98.46 is revised to read as follows:

§ 98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in § 98.36(d)(1).

- 18. Section 98.47 is revised to read as follows:

§ 98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§ 98.3(g) and 98.37. Records retained under § 75.57(h) of this chapter for missing data events satisfy the recordkeeping requirements of § 98.3(g)(4) for those same events.

Subpart F—[Amended]

- 19. Section 98.62 is amended by revising paragraphs (a) and (b) to read as follows:

§ 98.62 GHGs to report.

* * * * *

(a) Perfluoromethane (CF₄), and perfluoroethane (C₂F₆) emissions from anode effects in all prebake and Søderberg electrolysis cells.

(b) CO₂ emissions from anode consumption during electrolysis in all prebake and Søderberg electrolysis cells.

* * * * *

- 20. Section 98.63 is amended by:

■ a. In paragraph (a), revising the only sentence and the definitions of “E_{PFC},” and “E_m” in Equation F-1.

■ b. Revising the only sentence of paragraph (b).

■ c. Revising paragraph (c).

§ 98.63 Calculating GHG emissions.

(a) The annual value of each PFC compound (CF₄, C₂F₆) shall be estimated from the sum of monthly values using Equation F-1 of this section:

* * * * *

E_{PFC} = Annual emissions of each PFC compound from aluminum production (metric tons PFC).

E_m = Emissions of the individual PFC compound from aluminum production for the month “m” (metric tons PFC).

(b) Use Equation F-2 of this section to estimate CF₄ emissions from anode effect duration or Equation F-3 of this section to estimate CF₄ emissions from

overvoltage, and use Equation F-4 of this section to estimate C₂F₆ emissions from anode effects from each prebake and Søderberg electrolysis cell.

* * * * *

(c) You must calculate and report the annual process CO₂ emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section, the procedures in paragraphs (e) and (f) of this section, or the procedures in paragraph (g) of this section.

* * * * *

- 21. Section 98.64 is amended by revising the first sentence of paragraph (a); and by revising paragraph (b) to read as follows:

§ 98.64 Monitoring and QA/QC requirements.

(a) Effective December 31, 2010 for smelters with no prior measurement or effective December 31, 2012, for facilities with historic measurements, the smelter-specific slope coefficients, overvoltage emission factors, and weight fractions used in Equations F-2, F-3, and F-4 of this subpart must be measured in accordance with the recommendations of the EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminum Production (2008) (incorporated by reference, see § 98.7), except the minimum frequency of measurement shall be every 10 years unless a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine. * * *

(b) The minimum frequency of the measurement and analysis is annually except as follows:

(1) Monthly for anode effect minutes per cell day (or anode effect overvoltage and current efficiency).

(2) Monthly for aluminum production.

(3) Smelter-specific slope coefficients, overvoltage emission factors, and weight fractions according to paragraph (a) of this section.

* * * * *

■ 22. Section 98.65 is amended by revising the only sentence of paragraph (a) to read as follows:

§ 98.65 Procedures for estimating missing data.

* * * * *

(a) Where anode or paste consumption data are missing, CO₂ emissions can be estimated from

aluminum production per Equation F–8 of this section.

* * * * *

■ 23. Section 98.66 is amended by revising paragraph (c)(1) to read as follows:

§ 98.66 Data reporting requirements.

* * * * *

(c) * * *

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Söderberg electrolysis cells combined.

* * * * *

■ 24. Table F–1 to Subpart F of Part 98 is revised to read as follows:

TABLE F–1 TO SUBPART F OF PART 98—SLOPE AND OVERVOLTAGE COEFFICIENTS FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINUM PRODUCTION

Technology	CF ₄ slope coefficient [(kg CF ₄ /metric ton Al)/ (AE–Mins/cell-day)]	CF ₄ overvoltage coefficient [(kg CF ₄ /metric ton Al)/(mV)]	Weight fraction C ₂ F ₆ /CF ₄ [(kg C ₂ F ₆ /kg CF ₄)]
Center Worked Prebake (CWPB)	0.143	1.16	0.121
Side Worked Prebake (SWPB)	0.272	3.65	0.252
Vertical Stud Söderberg (VSS)	0.092	NA	0.053
Horizontal Stud Söderberg (HSS)	0.099	NA	0.085

■ 25. Table F–2 to Subpart F of Part 98 is amended by removing the entry for

“CO₂ Emissions from Pitch Volatiles Combustion (VSS and HSS)” and adding

a new entry in its place to read as follows:

TABLE F–2 TO SUBPART F OF PART 98—DEFAULT DATA SOURCES FOR PARAMETERS USED FOR CO₂ EMISSIONS

Parameter	Data source
CO₂ Emissions From Prebake Cells (CWPB and SWPB)	
* * * * *	* * * * *
CO ₂ Emissions From Pitch Volatiles Combustion (CWPB and SWPB)	
* * * * *	* * * * *

Subpart G—[Amended]

■ 26. Section 98.72 is amended by revising paragraphs (a) and (b) to read as follows:

§ 98.72 GHGs to report.

* * * * *

(a) CO₂ process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements of this subpart (CO₂ process emissions reported under this subpart may include CO₂ that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit).

(b) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources), by following the requirements of subpart C, except that for ammonia manufacturing processes subpart C does not apply to any CO₂ resulting from combustion of the waste recycle stream

(commonly referred to as the purge gas stream).

* * * * *

■ 27. Section 98.73 is amended by:

■ a. Revising paragraph (b) introductory text.

■ b. Revising the definition of “CO_{2,G}” in Equation G–1 of paragraph (b)(1).

■ c. Revising the definition of “CO_{2,L}” in Equation G–2 of paragraph (b)(2).

■ d. Revising the definition of “CO_{2,s}” in Equation G–3 of paragraph (b)(3).

■ e. Revising the definition of “CO₂” in Equation G–5 of paragraph (b)(5).

■ f. Removing paragraph (b)(6).

§ 98.73 Calculating GHG emissions.

* * * * *

(b) Calculate and report under this subpart process CO₂ emissions using the procedures in paragraphs (b)(1) through (b)(5) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) * * *

CO_{2,G,k} = Annual CO₂ emissions arising from gaseous feedstock consumption (metric tons).

* * * * *

(2) * * *

CO_{2,L,k} = Annual CO₂ emissions arising from liquid feedstock consumption (metric tons).

* * * * *

(3) * * *

CO_{2,s,k} = Annual CO₂ emissions arising from solid feedstock consumption (metric tons).

* * * * *

(5) * * *

CO₂ = Annual combined CO₂ emissions from all ammonia processing units (metric tons) (CO₂ process emissions reported under this subpart may include CO₂ that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit(s)).

* * * * *

■ 28. Section 98.74 is amended by revising paragraph (d) to read as set forth below and by removing and reserving paragraph (f):

§ 98.74 Monitoring and QA/QC requirements.

* * * * *

(d) Calibrate all oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes and flow rates (except for gas billing meters) according to the monitoring and QA/QC

requirements for the Tier 3 methodology in § 98.34(b)(1). Perform oil tank drop measurements (if used to quantify feedstock volumes) according to § 98.34(b)(2).

* * * * *

■ 29. Section 98.75 is amended by revising the first sentence of paragraph (a); and by revising paragraph (b) to read as follows:

§ 98.75 Procedures for estimating missing data.

* * * * *

(a) For missing data on monthly carbon contents of feedstock, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. * * *

(b) For missing feedstock supply rates used to determine monthly feedstock consumption, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

■ 30. Section 98.76 is amended by:

■ a. Revising paragraphs (a) introductory text and (b)(6).

■ b. Removing paragraphs (b)(12) through (b)(15).

■ c. Redesignating paragraph (b)(16) as paragraph (b)(12).

■ d. Adding paragraph (b)(13).

■ e. Removing paragraphs (b)(17) and (c).

§ 98.76 Data reporting requirements.

* * * * *

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

* * * * *

(b) * * *

(6) Sampling analysis results of carbon content of feedstock as determined for QA/QC of supplier data under § 98.74(e).

* * * * *

(13) CO₂ from the steam reforming of a hydrocarbon or the gasification of solid and liquid raw material at the ammonia manufacturing process unit used to produce urea and the method used to determine the CO₂ consumed in urea production.

Subpart P—[Amended]

■ 31. Section 98.163 is amended by revising the definitions of “CC_n” and “MW” in Equation P–1 of paragraph (b)(1) to read as follows:

§ 98.163 Calculating GHG emissions.

* * * * *

(b) * * *

(1) * * *

CC_n = Average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (kg carbon per kg of fuel and feedstock). If measurements are taken more frequently than monthly, use the arithmetic average of measurement values within the month to calculate a monthly average.

MW_n = Average molecular weight of the gaseous fuel and feedstock from the results of one or more analyses for month n (kg/kg-mole).

* * * * *

■ 32. Section 98.164 is amended by revising paragraphs (b)(1), (b)(2), and (b)(5) introductory text to read as follows:

§ 98.164 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(1) Calibrate all oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes (except for gas billing meters) according to the monitoring and QA/QC requirements for the Tier 3 methodology in § 98.34(b)(1). Perform oil tank drop measurements (if used to quantify liquid fuel or feedstock consumption) according to § 98.34(b)(2). Calibrate all solids weighing equipment according to the procedures in § 98.3(i).

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g., natural gas). For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), sample and analyze no less frequently than weekly to determine the carbon content and molecular weight of the fuel and feedstock.

* * * * *

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks. Alternatively, you may use the results of continuous chromatographic analysis of the fuel and feedstock, provided that the gas chromatograph (GC) is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the GC are documented in the written monitoring plan for the unit under § 98.3(g)(5).

* * * * *

Subpart V—[Amended]

■ 33. Section 98.226 is amended by removing and reserving paragraph (o).

Subpart X—[Amended]

■ 34. Section 98.240 is amended by revising paragraph (a); and by adding paragraph (g) to read as follows:

§ 98.240 Definition of the source category.

(a) The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, except as specified in paragraphs (b) through (g) of this section. The source category includes processes that produce the petrochemical as an intermediate in the on-site production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment off site.

* * * * *

(g) A process that solely distills or recycles waste solvent that contains a petrochemical is not part of the petrochemical production source category.

■ 35. Section 98.242 is amended by revising paragraph (a)(1) and paragraph (b) introductory text to read as follows:

§ 98.242 GHGs to report.

* * * * *

(a) * * *

(1) If you comply with § 98.243(b) or (d), report under this subpart the calculated CO₂, CH₄, and N₂O emissions for each stationary combustion source and flare that burns any amount of petrochemical process off-gas. If you comply with § 98.243(b), also report under this subpart the measured CO₂ emissions from process vents routed to stacks that are not associated with stationary combustion units.

* * * * *

(b) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units.

* * * * *

■ 36. Section 98.243 is amended by:

■ a. Revising the second sentence of paragraph (b).

■ b. Revising paragraph (c)(3).

■ c. Revising the definition of “MVC” in Equation X–1 in paragraph (c)(5)(i).

■ d. Revising paragraph (d).

§ 98.243 Calculating GHG emissions.

* * * * *

(b) * * * For each stack (except flare stacks) that includes emissions from combustion of petrochemical process off-gas, calculate CH₄ and N₂O emissions in accordance with subpart C of this

part (use the Tier 3 methodology, emission factors for "Petroleum" in Table C-2 of subpart C of this part, and either the default high heat value for fuel gas in Table C-1 of subpart C of this part or a calculated HHV, as allowed in Equation C-8 of subpart C of this part). * * *

(c) * * *

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample according to the procedures of § 98.244(b)(4). If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically. However, if a particular liquid or solid feedstock is delivered in lots, and if multiple deliveries of the same feedstock are received from the same supply source in a given calendar month, only one representative sample is required. Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month using any of the procedures specified in § 98.244(b)(4).

* * * * *

(5) * * *

(i) * * *

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

* * * * *

(d) *Optional combustion methodology for ethylene production processes.* For each ethylene production process, calculate GHG emissions from combustion units that burn fuel that contains any off-gas from the ethylene process as specified in paragraphs (d)(1) through (d)(5) of this section.

(1) Except as specified in paragraphs (d)(2) and (d)(5) of this section, calculate CO₂ emissions using the Tier 3 or Tier 4 methodology in subpart C of this part.

(2) You may use either Equation C-1 or Equation C-2a in subpart C of this part to calculate CO₂ emissions from combustion of any ethylene process off-gas streams that meet either of the conditions in paragraphs (d)(2)(i) or (d)(2)(ii) of this section (for any default values in the calculation, use the defaults for fuel gas in Table C-1 of subpart C of this part). Follow the otherwise applicable procedures in subpart C to calculate emissions from combustion of all other fuels in the combustion unit.

(i) The annual average flow rate of fuel gas (that contains ethylene process off-gas) in the fuel gas line to the combustion unit, prior to any split to

individual burners or ports, does not exceed 345 standard cubic feet per minute at 60 °F and 14.7 pounds per square inch absolute, and a flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(ii) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr, and a flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe.

(3) Except as specified in paragraph (d)(5) of this section, calculate CH₄ and N₂O emissions using the applicable procedures in § 98.33(c) for the same tier methodology that you used for calculating CO₂ emissions.

(i) For all gaseous fuels that contain ethylene process off-gas, use the emission factors for "Petroleum" in Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) For Tier 3, use either the default high heat value for fuel gas in Table C-1 of subpart C of this part or a calculated HHV, as allowed in Equation C-8 of subpart C of this part.

(4) You are not required to use the same Tier for each stationary combustion unit that burns ethylene process off-gas.

(5) For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology specified in §§ 98.253(b)(1) through (b)(3).

■ 37. Section 98.244 is amended by revising paragraphs (b)(1) through (b)(3), (b)(4) introductory text, and (b)(4)(viii); and by adding paragraphs (b)(4)(xi) through (b)(4)(xv) to read as follows:

§ 98.244 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(1) Operate, maintain, and calibrate belt scales or other weighing devices as described in Specifications, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices NIST Handbook 44 (2009) (incorporated by reference, see § 98.7), or follow procedures specified by the measurement device manufacturer. You must recalibrate each weighing device according to one of the following frequencies. You may recalibrate either at the minimum frequency specified by the manufacturer or biennially (*i.e.*, once every two years).

(2) Operate and maintain all flow meters used for gas and liquid feedstocks and products according to the manufacturer's recommended procedures. You must calibrate each of these flow meters as specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section:

(i) You may use either the calibration methods specified by the flow meter manufacturer or an industry consensus standard method. Each flow meter must meet the applicable accuracy specification in § 98.3(i), except as otherwise specified in §§ 98.3(i)(4) through (i)(6).

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

(3) You must perform tank level measurements (if used to determine feedstock or product flows) according to one of the following methods. You may use any standard method published by a consensus-based standards organization or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th Floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.api.org>).

(4) Beginning January 1, 2010, use any applicable methods specified in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section to determine the carbon content or composition of feedstocks and products and the average molecular weight of gaseous feedstocks and products. Calibrate instruments in accordance with paragraphs (b)(4)(i) through (b)(4)(xvi), as applicable. For coal used as a feedstock, the samples for carbon content determinations shall be

taken at a location that is representative of the coal feedstock used during the corresponding monthly period. For carbon black products, samples shall be taken of each grade or type of product produced during the monthly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed monthly or a composite of samples collected more frequently and analyzed monthly. Analyses conducted in accordance with methods specified in paragraphs (b)(4)(i) through (b)(4)(xv) of this section may be performed by the owner or operator, by an independent laboratory, or by the supplier of a feedstock.

* * * * *

(viii) Method 8015C, Method 8021B, Method 8031, or Method 9060A (all incorporated by reference, see § 98.7).

* * * * *

(xi) ASTM D2593–93 (Reapproved 2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography (incorporated by reference, see § 98.7).

(xii) ASTM D7633–10 Standard Test Method for Carbon Black—Carbon Content (incorporated by reference, see § 98.7).

(xiii) The results of chromatographic analysis of a feedstock or product, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(xiv) The carbon content results of mass spectrometer analysis of a feedstock or product, provided that the mass spectrometer is operated, maintained, and calibrated according to the manufacturer's instructions.

(xv) Beginning on January 1, 2010, the methods specified in paragraphs (b)(4)(xv)(A) and (B) of this section may be used as alternatives for the methods specified in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section.

(A) An industry standard practice for carbon black feedstock oils and carbon black products.

(B) Modifications of existing analytical methods or other methods that are applicable to your process provided that the methods listed in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe.

■ 38. Section 98.246 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(4).

■ b. Removing and reserving paragraph (a)(7).

■ c. Revising paragraph (a)(10).

■ d. Adding paragraph (a)(11).

■ e. Revising paragraphs (b) introductory text, and (b)(1) through (b)(5).

■ f. Revising paragraph (c).

§ 98.246 Data reporting requirements.

* * * * *

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (a)(11) of this section for each type of petrochemical produced, reported by process unit.

* * * * *

(4) Each of the monthly volume, mass, and carbon content values used in Equations X–1 through X–3 of this subpart (*i.e.*, the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the molecular weights used in Equation X–1 of this subpart, and the temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X–1 of this subpart were determined. Indicate whether you used the alternative to sampling and analysis specified in § 98.243(c)(4).

* * * * *

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the annual mass of carbon released in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(11) If you determine carbon content or composition of a feedstock or product using a method under § 98.244(b)(4)(xv)(B), report the information listed in paragraphs (a)(11)(i) through (a)(11)(iv) of this section. Include the information in paragraph (a)(11)(i) of this section in each annual report. Include the information in paragraphs (a)(11)(ii) and (a)(11)(iii) of this section only in the first applicable annual report, and provide any changes to this information in subsequent annual reports.

(i) Name or title of the analytical method.

(ii) A copy of the method. If the method is a modification of a method listed in §§ 98.244(b)(4)(i) through (xiv), you may provide a copy of only the sections that differ from the listed method.

(iii) An explanation of why an alternative to the methods listed in

§§ 98.244(b)(4)(i) through (xiv) is needed.

(b) If you measure emissions in accordance with § 98.243(b), then you must report the information listed in paragraphs (b)(1) through (b)(8) of this section.

(1) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(2) For CEMS used on stacks for stationary combustion units, report the relevant information required under § 98.36 for the Tier 4 calculation methodology. Section 98.36(b)(9)(iii) does not apply for the purposes of this subpart.

(3) For CEMS used on stacks that are not used for stationary combustion units, report the information required under § 98.36(e)(2)(vi).

(4) The CO₂ emissions from each stack and the combined CO₂ emissions from all stacks (except flare stacks) that handle process vent emissions and emissions from stationary combustion units that burn process off-gas for the petrochemical process unit. For each stationary combustion unit (or group of combustion units monitored with a single CO₂ CEMS) that burns petrochemical process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the petrochemical process unit.

(5) For stationary combustion units that burn process off-gas from the petrochemical process unit, report the information related to CH₄ and N₂O emissions as specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) The CH₄ and N₂O emissions from each stack that is monitored with a CO₂ CEMS, expressed in metric tons of each gas and in metric tons of CO₂e. For each stack provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the petrochemical process unit.

(ii) The combined CH₄ and N₂O emissions from all stationary combustion units, expressed in metric tons of each gas and in metric tons of CO₂e.

(iii) The quantity of each type of fuel used in Equation C–8 in § 98.33(c) for each stationary combustion unit or group of units (as applicable) during the reporting year, expressed in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(iv) The HHV (either default or annual average from measured data) used in Equation C–8 in § 98.33(c) for each

stationary combustion unit or group of combustion units (as applicable).

* * * * *

(c) If you comply with the combustion methodology specified in § 98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(5) of this section.

(1) The ethylene process unit ID or other appropriate descriptor.

(2) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), except flares, the relevant information listed in § 98.36 for the applicable Tier methodology. For each stationary combustion unit or group of units (as applicable) that burns ethylene process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.

(3) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns ethylene process off-gas.

(4) Name and annual quantity of each feedstock.

(5) Annual quantity of ethylene produced from each process unit (metric tons).

■ 39. Section 98.247 is amended by:

- a. Revising paragraph (a).
- b. Adding paragraph (b)(4).
- c. Revising paragraph (c).

§ 98.247 Records that must be retained.

* * * * *

(a) If you comply with the CEMS measurement methodology in § 98.243(b), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37, records of the procedures used to develop estimates of the fraction of total emissions attributable to combustion of petrochemical process off-gas as required in § 98.246(b), and records of any annual average HHV calculations.

(b) * * *

(4) The dates and results (*e.g.*, percent calibration error) of the calibrations of each measurement device.

(c) If you comply with the combustion methodology in § 98.243(d), then you must retain under this subpart the records required for the applicable Tier Calculation Methodologies in § 98.37. If you comply with § 98.243(d)(2), you must also keep records of the annual average flow calculations.

Subpart Y—[Amended]

■ 40. Section 98.252 is amended by revising paragraph (a) and the first sentence of paragraph (i) to read as follows:

§ 98.252 GHGs to report.

* * * * *

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

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

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

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

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

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

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

* * * * *

(i) CO₂ emissions from non-merchant hydrogen production process units (not including hydrogen produced from catalytic reforming units) under this subpart. * * *

■ 41. Section 98.253 is amended by:

- a. Revising paragraph (b)(1)(ii)(A).
- b. Revising the definition of “(Flare)_p” in Equation Y–2 in paragraph (b)(1)(ii)(B).
- c. Revising the definition of “MVC” in Equation Y–3 in paragraph (b)(1)(iii)(C).
- d. Revising paragraph (c)(1)(ii).
- e. Revising the definition of “MVC” in Equation Y–6 in paragraph (c)(2)(i).
- f. Revising paragraph (c)(2)(ii).
- g. Revising the definitions of “CB_Q” and “n” in Equation Y–11 in paragraph (e)(3).
- h. Revising the first sentence of paragraph (f) introductory text and the last sentence of paragraph (f)(1).
- i. Revising the definition of “MVC” in Equation Y–12 in paragraph (f)(4).
- j. Revising the definition of “M_{dust}” in Equation Y–13 in paragraph (g)(2).
- k. Revising paragraphs (h) introductory text and (h)(2).
- l. In paragraph (i)(1), revising the first two sentences and the definition of “MVC” in Equation Y–18.
- m. In paragraph (j), revising the first two sentences; and revising the definitions of “(VR)_p,” “(MF_x)_p,” and “MVC” in Equation Y–19.
- n. In paragraph (k), revising the first sentence and the definition of “MVC” in Equation Y–20.
- o. Revising paragraph (m) introductory text.
- p. Revising the only sentence of paragraph (m)(1).
- p. Revising the definitions of “MF_{CH₄}” and “MVC” in Equation Y–23 in paragraph (m)(2).
- q. Revising paragraph (n).

§ 98.253 Calculating GHG emissions.

* * * * *

(b) * * *

(1) * * *

(ii) * * *

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

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

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

44 = Molecular weight of CO_2 (kg/kg-mole).

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

$(Flare)_p$ = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term " $(MW)_p/MVC$ " with "1".

$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement

values within the day to calculate a daily average.

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

$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

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

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

$(Flare)_p$ = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, you must determine the average molecular weight of the flare gas during the measurement period and convert the mass flow to a volumetric flow.

44 = Molecular weight of CO_2 (kg/kg-mole).

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

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

$(\%CO_2)_p$ = Mole percent CO_2 concentration in the flare gas stream during the measurement period (mole percent = percent by volume).

y = Number of carbon-containing compounds other than CO_2 in the flare gas stream.

x = Index for carbon-containing compounds other than CO_2 .

0.98 = Assumed combustion efficiency of a flare (mole CO_2 per mole carbon).

$(\%C_x)_p$ = Mole percent concentration of compound "x" in the flare gas stream

during the measurement period (mole percent = percent by volume)

CMN_x = Carbon mole number of compound "x" in the flare gas stream (mole carbon atoms per mole compound). E.g., CMN for ethane (C_2H_6) is 2; CMN for propane (C_3H_8) is 3.

(B) * * *

$(Flare)_p$ = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: $Flare[MMscf] = 0.000001 \times Flare[kg] \times MVC/(MW)_p$, where MVC is the molar volume conversion factor [849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia depending on the standard conditions used when determining $(HHV)_p$] and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).

* * * * *

(iii) * * *

(C) * * *

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

* * * * *

(c) * * *

(1) * * *

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

(2) * * *

(i) * * *

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

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

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

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit

regenerator or fluid coking unit burner

prior to the combustion of other fossil fuels (dscfh).
 Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
 Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
 $\%O_2$ = Hourly average percent oxygen concentration in exhaust gas stream from

the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
 $\%O_{oxy}$ = O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
 $\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit

regenerator or fluid coking unit burner (percent by volume—dry basis).
 $\%CO$ = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume $\%CO$ to be zero.

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

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).

$\%N_{2,oxy}$ = N_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on measured value or maximum N_2 impurity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).

$\%N_{2,exhaust}$ = Hourly average percent N_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

* * * * *

(e) * * *

(3) * * *

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

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

* * * * *

(f) For on-site sulfur recovery plants and for sour gas sent off site for sulfur recovery, calculate and report CO_2 process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section, or, for non-Claus sulfur recovery plants, according to the requirements in paragraph (j) of this section regardless of the concentration of CO_2 in the vented gas stream. * * *

(1) * * * Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section, or (for non-Claus sulfur recovery plants only) follow the requirements in paragraph (j) of this section to determine CO_2 emissions for the sulfur recovery plant.

* * * * *

(4) * * *

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

* * * * *

(g) * * *

(2) * * *

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

* * * * *

(h) For asphalt blowing operations, calculate CO_2 and CH_4 emissions according to the requirements in paragraph (j) of this section regardless of the CO_2 and CH_4 concentrations or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

* * * * *

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 using either Equation Y-16a or Equation Y-16b of this section and calculate CH_4 emissions using Equation Y-17 of this section, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

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

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2 /year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

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

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data

(metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of CO_2 (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).

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

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2 /year).

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

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

EF_{AB,CO_2} = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2 /MMbbl asphalt blown); default = 1,100.

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

44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).

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

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (metric tons CH_4 /year).

0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.

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

EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4 /MMbbl asphalt blown); default = 580.

(i) * * *

(1) Use the process vent method in paragraph (j) of this section to calculate the CH_4 emissions from the depressurization of the coke drum or vessel regardless of the CH_4 concentration and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use the process vent method in paragraph (j) of this section and Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

* * * * *

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

* * * * *

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can reasonably be expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O , calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section to calculate CH_4 emissions for catalytic reforming unit depressurization and purge vents when

methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.

* * * * *

$(VR)_p$ = Average volumetric flow rate of process gas during the event (scf per hour) from measurement data, process knowledge, or engineering estimates.

$(MF_x)_p$ = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas) from measurement data, process knowledge, or engineering estimates.

* * * * *

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

* * * * *

(k) For uncontrolled blowdown systems, you must calculate CH_4 emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH_4 concentration or using Equation Y20 of this section. * * *

* * * * *

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

* * * * *

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

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

* * * * *

(2) * * *

MF_{CH_4} = Average mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tanks from facility measurements (kg-mole CH_4 /kg-mole gas); use 0.27 as a default if measurement data are not available.

* * * * *

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

* * * * *

(n) For crude oil, intermediate, or product loading operations for which the vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in AP 42, Section 5.2 (incorporated by reference, see § 98.7). For loading operations in which the vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

■ 42. Section 98.254 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (b).

■ c. Revising paragraph (c).

■ d. Revising paragraph (d) introductory text.

■ e. Adding paragraph (d)(6).

■ f. Revising paragraph (e) introductory text.

■ g. Revising paragraph (f) introductory text and (f)(1).

■ h. Removing and reserving paragraph (f)(2).

■ i. Removing paragraph (f)(4).

■ j. Revising paragraph (g).

■ k. Revising the second sentence of paragraph (h).

■ l. Removing paragraph (l).

§ 98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors that are associated with sources that use a CEMS to measure CO_2 emissions

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

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

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

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

(c) For flare or sour gas flow meters and gas flow meters used to comply with the requirements in § 98.253(j), operate, calibrate, and maintain the flow meter according to one of the following. You may use the procedures specified by the flow meter manufacturer, or a method published by a consensus-based standards organization. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), the American

Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, <http://www.api.org>).

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

(6) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see § 98.7).

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

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

(1) Locate the flow monitor at a site that provides representative flow rates. Avoid locations where there is swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

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

(h) * * * Calibrate the measurement device according to the procedures

specified by NIST handbook 44 (incorporated by reference, see § 98.7) or the procedures specified by the manufacturer. * * *

* * * * *

■ 43. Section 98.256 is amended by:

■ a. Revising paragraph (e)(6).

■ b. Redesignating paragraphs (e)(7) through (e)(9) as (e)(8) through (e)(10), respectively.

■ c. Adding paragraph (e)(7).

■ d. Revising newly designated paragraphs (e)(8) and (e)(9).

■ e. Revising paragraphs (f)(6) through (f)(8).

■ f. Redesignating paragraphs (f)(9) through (f)(12) as (f)(10) through (f)(13), respectively.

■ g. Adding paragraph (f)(9).

■ h. Revising newly designated paragraphs (f)(11) through (f)(13).

■ i. Revising paragraphs (g)(5), (h)(2), and (h)(4), and the first sentence of paragraph (h)(6).

■ j. Adding paragraph (h)(7).

■ k. Revising paragraphs (i)(5), (i)(6), (i)(8), and (j)(2).

■ l. Redesignating paragraph (j)(8) as (j)(9).

■ m. Adding paragraph (j)(8).

■ n. Revising paragraphs (k)(1), (k)(3), (l) introductory text, (l)(5), and (m).

■ o. Revising paragraphs (o)(1) through (o)(4).

§ 98.256 Data reporting requirements.

* * * * *

(e) * * *

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

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

(i) The annual average concentration of the compound (volume or mole percent).

(ii) The carbon mole number of the compound (moles carbon per mole compound).

(8) If you use Equation Y–2 of this subpart, an indication of whether daily

or weekly measurement periods are used, the annual volume of flare gas combusted (in million (MM) scf/year), the annual average higher heating value of the flare gas (in mmBtu/mmBtu), and an indication of whether the annual volume of flare gas combusted and the annual average higher heating value of the flare gas were determined using standard conditions of 68 °F and 14.7 psia or 60 °F and 14.7 psia.

(9) If you use Equation Y-3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in mmBtu/mmBtu), the number of SSM events exceeding 500,000 scf/day, the volume of gas flared (in scf/event), the average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.

* * * * *

(f) * * *

(6) If you use a CEMS, the relevant information required under § 98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS (unadjusted to remove CO₂ combustion emissions associated with additional units, if present) and the process CO₂ emissions as calculated according to § 98.253(c)(1)(ii). Report the CO₂ annual emissions associated with sources other than those from the coke burn-off in the applicable subpart (e.g., subpart C of this part in the case of a CO boiler).

(7) If you use Equation Y-6 of this subpart, the annual average exhaust gas flow rate, %CO₂, %CO, and the molar volume conversion factor (in scf/kg-mole).

(8) If you use Equation Y-7a of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %O₂, %O_{oxy}, %CO₂, and %CO.

(9) If you use Equation Y-7b of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %N_{2,oxy}, and %N_{2,exhaust}.

* * * * *

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH₄ emissions. If you use a unit-specific emission factor for CH₄, report the unit-specific emission factor for CH₄, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) Indicate whether you use a measured value, a unit-specific

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

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

(g) * * *

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

(h) * * *

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

* * * * *

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

* * * * *

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

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

(i) * * *

(5) If you use Equation Y-13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, the annual mass of coke dust removed from the process through dust collection systems, and an indication of whether coke dust is recycled to the unit (e.g., all dust is

recycled, a portion of the dust is recycled, or none of the dust is recycled).

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

* * * * *

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

(j) * * *

(2) The quantity of asphalt blown (in million bbl) at the unit in the reporting year.

* * * * *

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

* * * * *

(k) * * *

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

* * * * *

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

* * * * *

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

* * * * *

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

venting events and the cumulative venting time.

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

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

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

(3) For uncontrolled blowdown systems reporting under § 98.253(k), the total quantity (in million bbl) of crude oil plus the quantity of intermediate products received from off site that are processed at the facility in the reporting year, the methane emission factor used for uncontrolled blowdown systems, the basis for the value, and the molar volume conversion factor (in scf/kg-mole).

(4) For uncontrolled blowdown systems reporting under § 98.253(j), the relevant information required under paragraph (l)(5) of this section.

* * * * *

(o) * * *

(1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all storage tanks, except for those used to process unstabilized crude oil.

(2) For storage tanks other than those processing unstabilized crude oil:

(i) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (*i.e.*, either AP 42, Section 7.1 (incorporated by reference, see § 98.7), or Equation Y-22 of this section).

(ii) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off site that are processed at the facility in the reporting year.

(3) The cumulative CH₄ emissions (in metric tons of CH₄) for storage tanks used to process unstabilized crude oil or a statement that the facility did not receive any unstabilized crude oil during the reporting year.

(4) For storage tanks that process unstabilized crude oil:

(i) The method used to calculate the reported unstabilized crude oil storage tank emissions.

(ii) The quantity of unstabilized crude oil received during the calendar year (in MMbbl).

(iii) The average pressure differential (in psi).

(iv) The molar volume conversion factor (in scf/kg-mole).

(v) The average mole fraction of CH₄ in vent gas from unstabilized crude oil storage tanks and the basis for the mole fraction.

(vi) If you did not use Equation Y-23, the tank-specific methane composition data and the gas generation rate data used to estimate the cumulative CH₄ emissions for storage tanks used to process unstabilized crude oil.

* * * * *

■ 44. Section 98.257 is revised to read as follows:

§ 98.257 Records that must be retained.

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

Subpart AA—[Amended]

■ 45. Section 98.273 is amended by:

■ a. Revising paragraphs (a)(1) and (a)(2).

■ b. Revising the definition of “EF” in Equation AA-1 of paragraph (a)(3).

■ c. Revising paragraphs (b)(1) and (b)(2).

■ d. Revising paragraphs (c)(1) and (c)(2).

§ 98.273 Calculating GHG emissions.

(a) * * *

(1) Calculate fossil fuel-based CO₂ emissions from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO₂ emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate fossil fuel-based CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) * * *

(EF) = Default or site-specific emission factor for CO₂, CH₄, or N₂O, from Table AA-1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).

* * * * *

(b) * * *

(1) Calculate fossil CO₂ emissions from fossil fuels from direct

measurement of fossil fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO₂ emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH₄ and N₂O emissions from fossil fuels from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in § 98.33(c).

* * * * *

(c) * * *

(1) Calculate CO₂ emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO₂ emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH₄ and N₂O emissions from fossil fuel from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in § 98.33(c); use the default HHV listed in Table C-1 of subpart C and the default CH₄ and N₂O emissions factors listed in Table AA-2 of this subpart.

* * * * *

■ 46. Section 98.276 is amended by revising the introductory text and revising paragraph (e) to read as follows:

§ 98.276 Data reporting requirements.

In addition to the information required by § 98.3(c) and the applicable information required by § 98.36, each annual report must contain the information in paragraphs (a) through (k) of this section as applicable:

* * * * *

(e) The default or site-specific emission factor for CO₂, CH₄, or N₂O, used in Equation AA-1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).

* * * * *

■ 47. Table AA-2 to Subpart AA is revised to read as follows:

TABLE AA-2 TO SUBPART AA—KRAFT LIME KILN AND CALCINER EMISSIONS FACTORS FOR FOSSIL FUEL-BASED CH₄ AND N₂O

Fuel	Fossil fuel-based emissions factors (kg/mmBtu HHV)			
	Kraft lime kilns		Kraft calciners	
	CH ₄	N ₂ O	CH ₄	N ₂ O
Residual Oil				0.0003
Distillate Oil			0.0027	0.0004
Natural Gas	0.0027			0.0001
Biogas				0.0001
Petroleum coke			NA	^a NA

^a Emission factors for kraft calciners are not available.

Subpart OO—[Amended]

■ 48. Section 98.410 is amended by revising paragraph (b) to read as follows:

§ 98.410 Definition of the source category.

* * * * *

(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG includes the manufacture of a fluorinated GHG as an isolated intermediate for use in a process that will result in its transformation either at or outside of the production facility. Producing a fluorinated GHG also includes the creation of a fluorinated GHG (with the exception of HFC-23) that is captured and shipped off site for any reason, including destruction. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG, the creation of HFC-23 during the production of HCFC-22, the creation of intermediates that are created and transformed in a single process with no storage of the intermediates, or the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at § 98.414(a).

* * * * *

■ 49. Section 98.414 is amended by:

■ a. Adding second and third sentences to paragraph (a).

■ b. Revising paragraph (h).

■ c. Removing and reserving paragraph (j).

■ d. Adding new paragraphs (n) through (q).

§ 98.414 Monitoring and QA/QC requirements.

(a) * * * If the measured mass includes more than one fluorinated GHG, the concentrations of each of the fluorinated GHGs, other than low-concentration constituents, shall be measured as set forth in paragraph (n) of this section. For each fluorinated GHG, the mean of the concentrations of

that fluorinated GHG (mass fraction) measured under paragraph (n) of this section shall be multiplied by the mass measurement to obtain the mass of that fluorinated GHG coming out of the production process.

* * * * *

(h) You must measure the mass of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at § 98.410(b). Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. You must use flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, you must estimate the concentrations of the fluorinated GHG being destroyed considering current or previous representative concentration measurements and other relevant process information. You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.

* * * * *

(n) If the mass coming out of the production process includes more than one fluorinated GHG, you shall measure the concentrations of all of the fluorinated GHGs, other than low-concentration constituents, as follows:

(1) *Analytical Methods.* Use a quality-assured analytical measurement technology capable of detecting the analyte of interest at the concentration of interest and use a procedure validated with the analyte of interest at the concentration of interest. Where standards for the analyte are not

available, a chemically similar surrogate may be used. Acceptable analytical measurement technologies include but are not limited to gas chromatography (GC) with an appropriate detector, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR). Acceptable methods include EPA Method 18 in Appendix A-1 of 40 CFR part 60; EPA Method 320 in Appendix A of 40 CFR part 63; the Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, EPA-430-R-10-003, (March 2010) (incorporated by reference, see § 98.7); ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see § 98.7); or other analytical methods validated using EPA Method 301 in Appendix A of 40 CFR part 63 or some other scientifically sound validation protocol. The validation protocol may include analytical technology manufacturer specifications or recommendations.

(2) *Documentation in GHG Monitoring Plan.* Describe the analytical method(s) used under paragraph (n)(1) of this section in the site GHG Monitoring Plan as required under § 98.3(g)(5). At a minimum, include in the description of the method a description of the analytical measurement equipment and procedures, quantitative estimates of the method's accuracy and precision for the analytes of interest at the concentrations of interest, as well as a description of how these accuracies and precisions were estimated, including the validation protocol used.

(3) *Frequency of measurement.* Perform the measurements at least once by February 15, 2011 if the fluorinated GHG product is being produced on December 17, 2010. Perform the measurements within 60 days of commencing production of any fluorinated GHG product that was not

being produced on December 17, 2010. Repeat the measurements if an operational or process change occurs that could change the identities or significantly change the concentrations of the fluorinated GHG constituents of the fluorinated GHG product. Complete the repeat measurements within 60 days of the operational or process change.

(4) *Measure all product grades.* Where a fluorinated GHG is produced at more than one purity level (e.g., pharmaceutical grade and refrigerant grade), perform the measurements for each purity level.

(5) *Number of samples.* Analyze a minimum of three samples of the fluorinated GHG product that have been drawn under conditions that are representative of the process producing the fluorinated GHG product. If the relative standard deviation of the measured concentrations of any of the fluorinated GHG constituents (other than low-concentration constituents) is greater than or equal to 15 percent, draw and analyze enough additional samples to achieve a total of at least six samples of the fluorinated GHG product.

(o) All analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs and associated detectors, IR, FTIR and NMR devices, shall be calibrated at a frequency needed to support the type of analysis specified in the site GHG Monitoring Plan as required under § 98.414(n) and § 98.3(g)(5) of this part. Quality assurance samples at the concentrations of concern shall be used for the calibration. Such quality assurance samples shall consist of or be prepared from certified standards of the analytes of concern where available; if not available, calibration shall be performed by a method specified in the GHG Monitoring Plan.

(p) Isolated intermediates that are produced and transformed at the same facility are exempt from the monitoring requirements of this section.

(q) Low-concentration constituents are exempt from the monitoring and QA/QC requirements of this section.

■ 50. Section 98.416 is amended by:

■ a. Revising paragraph (a)(3).

■ b. Removing and reserving paragraph (a)(4).

■ c. Revising paragraphs (a)(11) and (a)(15).

■ d. Revising paragraphs (b) introductory text and (b)(1).

■ e. Revising paragraphs (c) introductory text, (c)(1), and (c)(10).

■ f. Revising paragraph (d) introductory text.

■ g. Revising paragraph (e) introductory text.

■ h. Adding paragraphs (f) through (h).

§ 98.416 Data reporting requirements.

* * * * *

(a) * * *

(3) Mass in metric tons of each fluorinated GHG that is destroyed at that facility and that was previously produced as defined at § 98.410(b). Quantities to be reported under this paragraph (a)(3) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

* * * * *

(11) Mass in metric tons of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at § 98.410(b). Quantities to be reported under this paragraph (a)(11) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

* * * * *

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of each fluorinated GHG that were sent to each for destruction.

* * * * *

(b) By March 31, 2011 or within 60 days of commencing fluorinated GHG destruction, whichever is later, a fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information for each destruction process:

(1) Destruction efficiency (DE).

* * * * *

(c) Each bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its imports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels that meet the conditions set forth at § 98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk, including each fluorinated GHG constituent of the fluorinated GHG product that makes up between 0.5 percent and 100 percent of the product by mass.

* * * * *

(10) If applicable, the names and addresses of the persons and facilities to which the fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of each fluorinated GHG that were sold or transferred to each facility for destruction.

(d) Each bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its exports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels. The report shall contain the following information for each export:

* * * * *

(e) By March 31, 2011, or within 60 days of commencing fluorinated GHG production, whichever is later, a fluorinated GHG production facility shall submit a one-time report describing the following information:

* * * * *

(f) By March 31, 2011, all fluorinated GHG production facilities shall submit a one-time report that includes the concentration of each fluorinated GHG constituent in each fluorinated GHG product as measured under § 98.414(n). If the facility commences production of a fluorinated GHG product that was not included in the initial report or performs a repeat measurement under § 98.414(n) that shows that the identities or concentrations of the fluorinated GHG constituents of a fluorinated GHG product have changed, then the new or changed concentrations, as well as the date of the change, must be reflected in a revision to the report. The revised report must be submitted to EPA by the March 31st that immediately follows the measurement under § 98.414(n).

(g) Isolated intermediates that are produced and transformed at the same facility are exempt from the reporting requirements of this section.

(h) Low-concentration constituents are exempt from the reporting requirements of this section.

■ 51. Section 98.417 is amended by revising paragraphs (a)(2), (b), and (d)(2); and by adding paragraphs (f) and (g) to read as follows:

§ 98.417 Records that must be retained.

(a) * * *

(2) Records documenting the initial and periodic calibration of the analytical equipment (including but not limited to GC, IR, FTIR, or NMR), weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the manufacturer directions or industry standards used for

calibration pursuant to § 98.414(m) and (o).

(b) In addition to the data required by paragraph (a) of this section, any fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report in § 98.416(b).

* * * * *

(d) * * *

(2) The invoice for the export.

* * * * *

(f) Isolated intermediates that are produced and transformed at the same facility are exempt from the recordkeeping requirements of this section.

(g) Low-concentration constituents are exempt from the recordkeeping requirements of this section.

■ 52. Section 98.418 is revised to read as follows:

§ 98.418 Definitions.

Except as provided below, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart shall take precedence for the reporting requirements in this subpart.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of chemical synthesis. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage.

Low-concentration constituent means, for purposes of fluorinated GHG production and export, a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.1 percent by mass. For purposes of fluorinated GHG import, low-concentration constituent means a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.5 percent by mass. Low-concentration constituents do not include fluorinated GHGs that are deliberately combined with the product (e.g., to affect the performance characteristics of the product).

Subpart PP—[Amended]

■ 53. Section 98.422 is amended by revising paragraphs (a) and (b) to read as follows:

§ 98.422 GHGs to report.

(a) Mass of CO₂ captured from production process units.

(b) Mass of CO₂ extracted from CO₂ production wells.

* * * * *

■ 54. Section 98.423 is amended by:

■ a. Revising the first sentence of paragraph (a) introductory text.

■ b. Revising the first sentences of paragraphs (a)(1) and (a)(2).

■ c. Revising the definitions of “C_{CO₂,p}” and “D_p” in Equation PP-2 in paragraph (a)(2).

■ d. Revising paragraph (a)(3).

■ e. Redesignating paragraph (b) as paragraph (c) and revising newly designated paragraph (c).

■ f. Adding paragraph (b).

§ 98.423 Calculating CO₂ Supply.

(a) Except as allowed in paragraph (b) of this section, calculate the annual mass of CO₂ captured, extracted, imported, or exported through each flow meter in accordance with the procedures specified in either paragraph (a)(1) or (a)(2) of this section. * * *

(1) For each mass flow meter, you shall calculate quarterly the mass of CO₂ in a CO₂ stream in metric tons by multiplying the mass flow by the composition data, according to Equation PP-1 of this section. * * *

* * * * *

(2) For each volumetric flow meter, you shall calculate quarterly the mass of CO₂ in a CO₂ stream in metric tons by multiplying the volumetric flow by the concentration and density data, according to Equation PP-2 of this section. * * *

* * * * *

C_{CO₂,p} = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (measured as either volume % CO₂ or weight % CO₂).

* * * * *

D_p = Density of CO₂ in quarter p (metric tons CO₂ per standard cubic meter) for flow meter u if C_{CO₂,p} is measured as volume % CO₂, or density of the whole CO₂ stream for flow meter u (metric tons per standard cubic meter) if C_{CO₂,p} is measured as weight % CO₂.

* * * * *

(3) To aggregate data, use either Equation PP-3a or PP-3b in this paragraph, as appropriate.

(i) For facilities with production process units that capture a CO₂ stream and either measure it after segregation or do not segregate the flow, calculate the total CO₂ supplied in accordance with Equation PP-3a.

$$CO_2 = \sum_{p=1}^U CO_{2,u} \quad (\text{Eq. PP-3a})$$

Where:

CO₂ = Total annual mass of CO₂ (metric tons).

CO_{2,u} = Annual mass of CO₂ (metric tons) through flow meter u.

u = Flow meter.

(ii) For facilities with production process units that capture a CO₂ stream and measure it ahead of segregation,

calculate the total CO₂ supplied in accordance with Equation PP-3b.

$$CO_2 = \sum_{p=1}^U CO_{2,u} - \sum_{p=1}^V CO_{2,v} \quad (\text{Eq. PP-3b})$$

Where:

CO₂ = Total annual mass of CO₂ (metric tons).

CO_{2,u} = Annual mass of CO₂ (metric tons) through main flow meter u.

CO_{2,v} = Annual mass of CO₂ (metric tons) through subsequent flow meter v for use on site.

u = Main flow meter.

v = Subsequent flow meter.

(b) As an alternative to paragraphs (a)(1) through (3) of this section for CO₂ that is supplied in containers, calculate the annual mass of CO₂ supplied in containers delivered by each CO₂ stream

in accordance with the procedures specified in either paragraph (b)(1) or (b)(2) of this section. If multiple CO₂ streams are used to deliver CO₂ to containers, you shall calculate the annual mass of CO₂ supplied in containers delivered by all CO₂ streams according to the procedures specified in paragraph (b)(3) of this section.

(1) For each CO₂ stream that delivers CO₂ to containers, for which mass is measured, you shall calculate CO₂ supply in containers using Equation PP-1 of this section.

Where:

CO_{2,u} = Annual mass of CO₂ (metric tons) supplied in containers delivered by CO₂ stream u.

C_{CO₂,p,u} = Quarterly CO₂ concentration measurement of CO₂ stream u that delivers CO₂ to containers in quarter p (wt. %CO₂).

Q_{p,u} = Quarterly mass of contents supplied in all containers delivered by CO₂ stream u in quarter p (metric tons).

p = Quarter of the year.

u = CO₂ stream that delivers to containers.

(2) For each CO₂ stream that delivers to containers, for which volume is measured, you shall calculate CO₂ supply in containers using Equation PP-2 of this section.

Where:

CO_{2,u} = Annual mass of CO₂ (metric tons) supplied in containers delivered by CO₂ stream u.

C_{CO₂,p} = Quarterly CO₂ concentration measurement of CO₂ stream u that delivers CO₂ to containers in quarter p (measured as either volume % CO₂ or weight % CO₂).

Q_p = Quarterly volume of contents supplied in all containers delivered by CO₂ stream u in quarter p (standard cubic meters).

D_p = Quarterly CO₂ density determination for CO₂ stream u in quarter p (metric tons per standard cubic meter) if CO_{2,p} is measured as volume % CO₂, or density of CO₂ stream u (metric tons per

standard cubic meter) if CO_{2,p} is measured as weight % CO₂.

p = Quarter of the year.

u = CO₂ stream that delivers to containers.

(3) To aggregate data, sum the mass of CO₂ supplied in containers delivered by all CO₂ streams in accordance with Equation PP-3a of this section.

Where:

CO₂ = Annual mass of CO₂ (metric tons) supplied in containers delivered by all CO₂ streams.

CO_{2,u} = Annual mass of CO₂ (metric tons) supplied in containers delivered by CO₂ stream u.

u = CO₂ stream that delivers to containers.

(c) Importers or exporters that import or export CO₂ in containers shall calculate the total mass of CO₂ imported or exported in metric tons based on summing the mass in each CO₂ container using weigh bills, scales, or load cells according to Equation PP-4 of this section.

$$CO_2 = \sum_{p=1}^I Q \quad (\text{Eq. PP-4})$$

Where:

CO₂ = Annual mass of CO₂ (metric tons).

Q = Annual mass in all CO₂ containers imported or exported during the reporting year (metric tons).

- 55. Section 98.424 is amended by:
- a. Revising paragraphs (a)(1), (a)(2), and (a)(5).
- b. Revising the second sentence of paragraph (b)(2).
- c. Adding paragraph (c).

§ 98.424 Monitoring and QA/QC requirements.

(a) * * *

(1) Reporters following the procedures in § 98.423(a) shall determine quantity using a flow meter or meters located in accordance with this paragraph.

(i) If the CO₂ stream is segregated such that only a portion is captured for commercial application or for injection, you must locate the flow meter according to the following:

(A) For reporters following the procedures in § 98.423(a)(3)(i), you must locate the flow meter(s) after the point of segregation.

(B) For reporters following the procedures in paragraph (a)(3)(ii) of § 98.423, you must locate the main flow meter(s) on the captured CO₂ stream(s) prior to the point of segregation and the subsequent flow meter(s) on the CO₂ stream(s) for on-site use after the point of segregation. You may only follow the procedures in paragraph (a)(3)(ii) of § 98.423 if the CO₂ stream(s) for on-site

use is/are the only diversion(s) from the main, captured CO₂ stream(s) after the main flow meter location(s).

(ii) Reporters that have a mass flow meter or volumetric flow meter installed to measure the flow of a CO₂ stream that meets the requirements of paragraph (a)(1)(i) of this section shall base calculations in § 98.423 of this subpart on the installed mass flow or volumetric flow meters.

(iii) Reporters that do not have a mass flow meter or volumetric flow meter installed to measure the flow of the CO₂ stream that meets the requirements of paragraph (a)(1)(i) of this section shall base calculations in § 98.423 of this subpart on the flow of gas transferred off site using a mass flow meter or a volumetric flow meter located at the point of off-site transfer.

(2) Reporters following the procedures in paragraph (b) of § 98.423 shall determine quantity in accordance with this paragraph.

(i) Reporters that supply CO₂ in containers using weigh bills, scales, or load cells shall measure the mass of contents of each CO₂ container to which the CO₂ stream is delivered, sum the mass of contents supplied in all containers to which the CO₂ stream is delivered during each quarter, sample the CO₂ stream delivering CO₂ to containers on a quarterly basis to determine the composition of the CO₂ stream, and apply Equation PP-1.

(ii) Reporters that supply CO₂ in containers using loaded container volumes shall measure the volume of contents of each CO₂ container to which the CO₂ stream is delivered, sum the volume of contents supplied in all containers to which the CO₂ stream is delivered during each quarter, sample the CO₂ stream on a quarterly basis to determine the composition of the CO₂ stream, determine the density quarterly, and apply Equation PP-2.

* * * * *

(5) Reporters using Equation PP-2 of this subpart and measuring CO₂ concentration as weight % CO₂ shall determine the density of the CO₂ stream on a quarterly basis in order to calculate the mass of the CO₂ stream according to one of the following procedures:

(i) You may use a method published by a consensus-based standards organization. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of

Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, <http://www.api.org>). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(ii) You may follow an industry standard method.

(b) * * *

(2) * * * Acceptable methods include, but are not limited to, the U.S. Food and Drug Administration food-grade specifications for CO₂ (see 21 CFR 184.1240) and ASTM standard E1747–95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications (ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>).

(c) You shall convert the density of the CO₂ stream(s) and all measured volumes of carbon dioxide to the following standard industry temperature and pressure conditions: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. If you apply the density value for CO₂ at standard conditions, you must use 0.001868 metric tons per standard cubic meter.

■ 56. Section 98.425 is amended by revising paragraph (a) introductory text; and by adding paragraph (d) to read as follows:

§ 98.425 Procedures for estimating missing data.

(a) Whenever the quality assurance procedures in § 98.424(a)(1) of this subpart cannot be followed to measure quarterly mass flow or volumetric flow of CO₂, the most appropriate of the following missing data procedures shall be followed:

* * * * *

(d) Whenever the quality assurance procedures in § 98.424(a)(2) of this subpart cannot be followed to measure quarterly quantity of CO₂ in containers, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly quantity of CO₂ in containers that is missing may be substituted with a quarterly value measured during another representative quarter of the current reporting year.

(2) A quarterly quantity of CO₂ in containers that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) The quarterly quantity of CO₂ in containers recorded for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any period during which measurement equipment is inoperable.

■ 57. Section 98.426 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(2).

■ b. Adding paragraph (a)(5).

■ c. Revising paragraphs (b) introductory text, (b)(2), (b)(3), and (b)(4).

■ d. Adding paragraph (b)(7).

■ e. Revising paragraphs (c) and (e)(1).

§ 98.426 Data reporting requirements.

* * * * *

(a) If you use Equation PP–1 of this subpart, report the following information for each mass flow meter or CO₂ stream that delivers CO₂ to containers:

* * * * *

(2) Quarterly mass in metric tons of CO₂.

* * * * *

(5) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.

* * * * *

(b) If you use Equation PP–2 of this subpart, report the following information for each volumetric flow

meter or CO₂ stream that delivers CO₂ to containers:

* * * * *

(2) Quarterly volume in standard cubic meters of CO₂.

(3) Quarterly concentration of the CO₂ stream in volume or weight percent.

(4) Report density as follows:

(i) Quarterly density of CO₂ in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in weight percent.

(ii) Quarterly density of the CO₂ stream in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in volume percent.

* * * * *

(7) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.

(c) For the aggregated annual mass of CO₂ emissions calculated using Equation PP–3a or PP–3b, report the following:

(1) If you use Equation PP–3a of this subpart, report the annual CO₂ mass in metric tons from all flow meters and CO₂ streams that deliver CO₂ to containers.

(2) If you use Equation PP–3b of this subpart, report:

(i) The total annual CO₂ mass through main flow meter(s) in metric tons.

(ii) The total annual CO₂ mass through subsequent flow meter(s) in metric tons.

(iii) The total annual CO₂ mass supplied in metric tons.

(iv) The location of each flow meter in relation to the point of segregation.

* * * * *

(e) * * *

(1) The type of equipment used to measure the total flow of the CO₂ stream or the total mass or volume in CO₂ containers.

* * * * *

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