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Part II

Environmental Protection Agency

40 CFR Part 98

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

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 98**

[EPA-HQ-OAR-2008-0508; FRL-9179-8]

RIN 2060-AQ33

Mandatory Reporting of Greenhouse Gases**AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Proposed Rule.

SUMMARY: EPA is proposing to amend specific provisions in the GHG 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 proposed changes include providing additional information and clarity on existing requirements, allowing greater flexibility or simplified calculation methods for certain sources in a facility, amending data reporting requirements to provide additional clarity on when different types of GHG emissions need to be calculated and reported, clarifying terms and definitions in certain equations, and technical corrections.

DATES: *Comments.* Comments must be received on or before September 27, 2010.

Public Hearing. EPA does not plan to conduct a public hearing unless requested. To request a hearing, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section by August 18, 2010. If requested, the hearing will be conducted August 26, 2010, at 1310 L St., NW., Washington, DC 20005 starting at 9 a.m., local time. EPA will provide further information about the hearing on its Web page if a hearing is requested.

ADDRESSES: You may submit your comments, identified by docket ID No. EPA-HQ-OAR-2008-0508 by any of the following methods:

- *Federal eRulemaking Portal:* <http://www.regulations.gov>. Follow the online instructions for submitting comments.

- *E-mail:* MRR_Revisions@epa.gov. Include docket ID No. EPA-HQ-OAR-2008-0508 [and/or RIN number 2060-aq33] in the subject line of the message.

- *Fax:* (202) 566-1741.

- *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Mailcode 2822T, Attention Docket ID No. EPA-HQ-OAR-2008-0508, 1200 Pennsylvania Avenue, NW., Washington, DC 20004.

- *Hand/Courier Delivery:* EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA-HQ-OAR-2008-0508, Revision of Certain GHGMRR Provisions and Other Corrections. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at <http://www.regulations.gov>, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through <http://www.regulations.gov> or e-mail. The <http://www.regulations.gov> Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through <http://www.regulations.gov> your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: 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., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in <http://www.regulations.gov> or in hard copy at the Air Docket, EPA/DC, 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 GENERAL 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 contact the Greenhouse Gas Reporting Rule Hotline at telephone number: (877) 444-1188; or e-mail: ghgmrr@epa.gov. To obtain information about the public hearings or to register to speak at the hearings, please go to <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>. Alternatively, contact Carole Cook at 202-343-9263.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of today's proposal will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on EPA's greenhouse gas reporting rule Web site at <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>.

SUPPLEMENTARY INFORMATION:

Additional Information on Submitting Comments: To expedite review of your comments by Agency staff, you are encouraged to send a separate copy of your comments, in addition to the copy you submit to the official docket, to Carole Cook, U.S. EPA, Office of Atmospheric Programs, Climate Change Division, Mail Code 6207-J, Washington, DC 20460, telephone (202) 343-9263, e-mail address: GHGReportingRule@epa.gov.

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 proposed amendments to existing regulations. If finalized, these amended regulations would affect owners or operators of certain fossil fuel and industrial gas suppliers, and direct emitters of 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.
HCFC-22 Production and HFC-23 Destruction.	325120	Chlorodifluoromethane manufacturing facilities.
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.
	331419	Primary lead smelting and refining facilities.
Lead Production	331492	Secondary lead smelting and refining facilities.
Lime Production	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Iron and Steel Production	331111	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace shops.
	331419	Primary lead smelting and refining facilities.
Nitric Acid Production	325311	Nitric acid production facilities.
Petrochemical Production	32511	Ethylene dichloride production facilities.
	325199	Acrylonitrile, ethylene oxide, methanol production facilities.
	325110	Ethylene production facilities.
	325182	Carbon black production facilities.
	324110	Petroleum refineries.
Petroleum Refineries	325312	Phosphoric acid manufacturing facilities.
Phosphoric Acid Production ... Pulp and Paper Manufacturing.	322110	Pulp mills.
	322121	Paper mills.
	322130	Paperboard mills.
	327910	Silicon carbide abrasives manufacturing facilities.
	325181	Alkalies and chlorine manufacturing facilities.
Soda Ash Manufacturing	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 ¹	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.
	221210	Natural gas distribution facilities.
Suppliers of Natural Gas and NGLs.	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.

¹ EPA will not be implementing subpart JJ of Part 98 using funds provided in its FY2010 appropriations 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 likely to be affected by this action. Table 1 of this preamble lists the types of facilities that EPA is now aware could potentially be affected by the reporting requirements. Other types of facilities 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 sections related to fossil fuel and industrial gas suppliers, and direct emitters of GHGs. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER GENERAL INFORMATION CONTACT** Section.

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

ACC American Chemistry Council
 AGA American Gas Association
 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
 Btu/scf British thermal unit per standard cubic foot
 CAA Clean Air Act
 CAIR Clean Air Interstate Rule
 CBI confidential business information
 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
 EGU electricity generating unit
 EIA Energy Information Administration
 EO Executive Order
 EPA U.S. Environmental Protection Agency
 ERC Energy Recovery Council
 FGD flue gas desulfurization
 FR Federal Register
 FTIR fourier transform infrared
 GC gas chromatography
 GHG greenhouse gas
 GPA Gas Processors Association
 GWP global warming potential
 HCl hydrogen chloride
 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
 MWC municipal waste combustor
 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
 O&M operation and maintenance
 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
 RFG Refinery fuel gas
 RGGI Regional Greenhouse Gas Initiative
 scf standard cubic feet
 scfm standard cubic feet per minute
 SO₂ sulfur dioxide
 SWPB side worked prebake
 U.S. United States
 UMRA Unfunded Mandates Reform Act of 1995
 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 proposed rule amendments and request for public comment. This section also discusses EPA's use of our legal authority under the Clean Air Act to collect data on GHGs.

The second section of this preamble describes in detail the changes that are being proposed to correct technical errors or to address implementation issues identified by EPA and others. This section also presents EPA's rationale for the proposed changes and identifies issues on which EPA is particularly interested in receiving public comments.

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

B. Background on This Action

The final Part 98 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, October 30, 2009). Part 98, which became effective on December 29, 2009, 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 suppliers of fossil fuels and industrial gases.

This is the second time that EPA has published a notice proposing amendments to Part 98 to, among other things, correct certain technical and editorial errors that have been identified since promulgation and clarify or

¹ Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128.

propose amendments to certain provisions that have been the subject of questions from reporting entities. The first proposal was published on June 15, 2010 (75 FR 33950). This proposal complements the proposal published on June 15, 2010 and is not intended to duplicate or replace the proposed amendments published on June 15, 2010. We are seeking public comment only on the issues specifically identified in this proposal for the identified subparts. We will not respond to any comments addressing other aspects of Part 98 or any other related rulemakings.

C. Legal Authority

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

As stated in the preamble to the final Part 98 (74 FR 56260, October 30, 2009), CAA section 114 provides EPA broad authority to require the information proposed to be gathered 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), section 114(a)(1) of the CAA authorizes the Administrator to require emissions sources, persons subject to the CAA, manufacturers of control equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA. 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 would these amendments apply to 2011 reports?

EPA is planning to address the comments on these proposed amendments and publish the final amendments before the end of 2010. Therefore, reporters would be expected to calculate emissions and other relevant data for the reports that are submitted in 2011 using Part 98, as amended by this and the other revisions package (75 FR 33950), as finalized. We have determined that it is feasible for the sources to implement these changes for the 2010 reporting year since the revisions primarily provide additional clarifications or flexibility 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.

For example, many proposed revisions simply provide additional information and clarity on existing requirements. For example, we are proposing to amend 40 CFR 98.3(c)(5)(i) to clarify that suppliers of industrial fluorinated GHGs need to calculate and report GHG emissions in metric tons of CO₂ equivalents (mtCO₂e) only for those fluorinated GHGs that are listed in Table A-1. This proposed clarification is consistent with clarifications we have issued in response to industry questions and would not change how facilities collected data during 2010.

Some of the proposed amendments provide greater flexibility or simplified calculation methods for certain facilities. For example, we are proposing to amend subpart C by adding a new equation that would enable sources that receive natural gas billing data from their suppliers in therms 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.

Some proposed amendments are to the data reporting requirements to provide additional clarity on when different types of GHG emissions need to be calculated and reported. For example, in subpart G, Ammonia Manufacturing, we are proposing to eliminate the calculation and reporting of CO₂ emissions associated with the use of the waste recycle stream or "purge" as fuel under subpart C because these emissions are already accounted for in the calculation of total process emissions in subpart G, which includes CO₂ emissions resulting from the use of purge gas as a fuel. We have concluded that amendments such as these can be implemented for the reports submitted to EPA in 2011 because the proposed changes are consistent with the calculation methodologies already in part 98 and the owners or operators are not required to actually report until March 2011, several months after we expect this proposal to be finalized.

For some subparts, we are proposing amendments to address issues identified as a result of working with the affected sources during rule implementation. These proposed revisions provide additional flexibility to the sources, or reduce the reporting burden. For example, in subparts X (Petrochemical Production) and Y (Petroleum Refineries), reporters have requested that allowance be made for alternative standard conditions within the molar

volume conversion factor (MVC) used in various equations. Therefore, we are proposing to amend those subparts to include MVCs at standard conditions defined at both 60°F or 68°F, so the facilities will not have to make those corrections in their data.

We are also proposing corrections to terms and definitions in certain equations. For example, in subpart Y, Petroleum Refineries, we are proposing to clarify in an equation that for coke calcining units that recycle the collected coke 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. These clarifications do not result in additional requirements; therefore, we have concluded that reporters can follow Part 98, as amended, in submitting their first reports in 2011.

Finally, we are proposing other technical corrections that have no impact on facility's data collection efforts in 2010. For example, we are proposing to amend subpart C to remove a second copy of Table C-2 that was inadvertently included in the final Part 98 published on October 30, 2009.

In summary, these amendments would not require any additional monitoring or information collection above what was already included in Part 98. Therefore, we expect that sources can use the same information that they have been collecting under the current version of Part 98 to calculate and report GHG emissions for 2010 and submit reports in 2011 under the amended Part 98.

We seek comment on the conclusion that it is appropriate to implement these amendments and incorporate the requirements in the data reported to EPA by March 31, 2011. Further, we seek comment on whether there are specific subparts of Part 98 for which this timeline may not be feasible or appropriate due to the nature of the proposed changes or the way in which data have been collected thus far in 2010. We request that commenters provide specific examples of how the proposed implementation schedule would or would not work.

II. Revisions and Other Amendments

Following promulgation of Part 98, we have identified errors in the regulatory language that we are now proposing to correct. These errors were identified as a result of working with affected industries to implement the various subparts of Part 98. We have also identified certain rule provisions that should be amended to provide greater clarity. We are also proposing revisions to provide additional

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>.

flexibility for certain requirements based in part on our better understanding of various industries. Finally, we are also proposing to revise or remove certain applicability thresholds (for example for local distribution companies subject to subpart NN (Suppliers of Natural Gas and Natural Gas Liquids)) and monitoring thresholds and reporting requirements (for example for municipal solid waste combustors subject to subpart C (General Stationary Fuel Combustion) and for certain small sources subject to subpart X (Petrochemicals) or subpart Y (Petroleum Refineries)). The amendments we are now proposing include the following types of changes:

- Changes to correct cross references within and between subparts.
- Additional information to better or more fully understand 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.
- Other amendments related to certain issues identified as a result of working with the affected sources during rule implementation and outreach.

As mentioned above in section I of this preamble, we published an earlier proposed rulemaking proposing technical corrections and other amendments to Part 98 on June 15, 2010 (75 FR 33950). This proposal complements the notice published on June 15, 2010 and is not intended to duplicate or replace the proposed amendments published on June 15, 2010. We are seeking public comment only on the issues specifically identified in this notice for the identified subparts. We will not respond to any comments addressing other aspects of Part 98 or any other related rulemakings.

A. Subpart A (General Provisions): Best Available Monitoring Methods

Certain owners and operators in the more complex hydrogen, petrochemical, and petroleum refinery industries have expressed concerns regarding the timing of the requirements to install meters and other measurement devices to comply with Part 98. Specifically, they were concerned that the safe installation of required measurement devices requires detailed engineering and planning and,

therefore, stated that EPA should provide sufficient time for designing and safely engineering instrumentation installations or upgrades. Further, they claimed that in continuously operated plants there is typically not a scheduled shutdown for an entire facility and unit maintenance and turnarounds are not an annual occurrence for all units. Reporters in these industries have asserted that EPA has properly recognized this operational reality in the context of instrument calibration by allowing calibration to be delayed until the next scheduled shutdown. The reporters have noted, however, that parallel requirements have not been developed for installation of monitoring devices. Specifically, they requested that EPA should provide approval criteria for extending the use of "best available monitoring methods" (BAMM) beyond December 31, 2010 for equipment installation.

These types of concerns were the reason owners and operators were given the opportunity in Part 98 to request an extension from EPA to use BAMM beyond March 31, 2010 in situations where it was not reasonably feasible to acquire, install and operate the required monitoring equipment by that date. We recognize, however, that instances may occur where facilities subject to Part 98 may not have been scheduled to shutdown during 2010, and requiring the facility to shutdown solely to install the required measurement devices during 2010 could impose an unnecessary burden.

Therefore, we are proposing that a new petition process be established in a new paragraph 40 CFR 98.3(j) that would allow use of BAMM past December 31, 2010 for owners and operators required to report under subpart P (Hydrogen Production), subpart X (Petrochemicals Production), or subpart Y (Petroleum Refineries), under limited circumstances. We are proposing that owners or operators subject to these subparts could petition EPA to extend use of BAMM past December 31, 2010, if compliance with a specific provision in the regulation required measurement device installation, and installing the device(s) would necessitate an unscheduled process equipment or unit shutdown or could only be installed through a hot tap. If the petition is approved, the owner or operator could 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.

The initial process for use of best available monitoring methods in Part 98 ended December 31, 2010, because we concluded that it is important to establish a date by which all equipment must be installed and operating in order to ensure that consistent data are collected by all reporters. We maintain that it is important to have consistent methods being used by all reporters. However, we also recognize that some complex facilities have unique operating circumstances that justify additional flexibility. Therefore, although we are proposing to initially approve extension requests no later than December 31, 2013, owners or operators subject to these subparts would have a one time opportunity to re-apply for the extension request for an additional two years, with approval being granted no later than December 31, 2015. We believe that a date of December 31, 2013, four years after the effective date of Part 98, would accommodate the shutdown schedules for most, if not all facilities subject to subparts P, X, and/or Y. Because we recognize that all such facilities subject to Part 98 may not have a planned process equipment or unit shutdown prior to December 31, 2013, we have concluded that it is reasonable to propose that owners or operators could re-apply one time for an additional two years. This timeline balances the need to gather consistent data, while recognizing the operational reality of such facilities.

Process for Requesting an Extension of Best Available Monitoring Methods. We are proposing to add a similar petition process to that recently concluded for the use of BAMM for 2010 in the new paragraph 40 CFR 98.3(j). The process would be available solely for 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 would be allowable initially until December 31, 2013. Subpart P, X, and/or Y owners or operators requesting to use BAMM beyond 2010 would be 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 would require a hot tap or unscheduled shutdown.

Owners or operators would be required to submit the full extension request for BAMM by February 15, 2011. The full extension requests would

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 would not be accomplished in 2010 with supporting material, an estimated date for the next planned maintenance outage, and a discussion of how emissions would be calculated in the interim. More specifically, the full extension request would need to 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 would also be required to 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 would automatically be able to use BAMM through June 30, 2011. All measurement devices would need to be installed by July 1, 2011 unless EPA approves the BAMM request before that date.

Approval of Extension Requests. In an approval of an extension request, EPA would 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 would have until the date approved by EPA to install any remaining meters or other measurement devices, however initial approvals would 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 would be 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 proposed process for BAMM would 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 proposing to include a process by which owners or operators who had received an extension would 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 moved would be required to notify EPA within 4 weeks of such a determination, but no later than 4 weeks before the date of 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, they would be required to 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, owners or operators would be required to submit a new extension request by June 1, 2013 that contains the information required in proposed 40 CFR 98.3(j)(4). All owners or operators that submit a request under this paragraph to extend use of best available monitoring methods for measurement device installation would be required to install all measurement devices by December 31, 2013, unless the extension request under this paragraph is approved by EPA.

We seek comment on this approach to extend the deadline for installation of measurement devices in cases where such installation would require an unscheduled process equipment or unit shutdown at a subpart P, X, and/or Y facility. The proposed approach is consistent with the language and intent in Part 98 to defer calibration of required monitors in order to avoid unnecessary and unplanned shutdowns. The proposed approach is also modeled after the provision to request EPA to use BAMM during 2010. We considered, but did not propose, limiting this provision to only those subpart P, X, and/or Y owners and operators who submitted a request for use of BAMM by January 28, 2010. This option was considered based on an assumption that the full universe of reporters that had difficulty installing

the necessary measurement devices according to the schedule in the rule would have already submitted a request for the use of BAMM in 2010. We still believe that all owners or operators that required a process equipment or unit shutdown to install measurement devices should have submitted an extension request to EPA by January 28, 2010. Nevertheless, we also recognize that this is a new regulation and facilities subject to Part 98 are making good faith efforts to understand all requirements. After careful consideration we are proposing to initiate a new process for BAMM, providing all facilities with units subject to subpart P, subpart X or subpart Y the opportunity to apply.

We are proposing to limit the provision to facilities with units subject to one or more of these three subparts because, based on questions received during implementation, the concerns raised about installation of measurement devices necessitating process equipment or unit shutdown have been from facilities subject to these subparts. A clear case was not presented by other industries as to any unique circumstances in those industries (e.g., safety concerns associated with installation of measurement devices, frequency of shutdowns, complexities associated with shutting down, etc.) that might necessitate extending the deadline for BAMM for these other industries. We are seeking comment on this conclusion and whether there are other facilities beyond these subparts P, X, and Y that would need a shutdown, or a hot tap, in order to install the required measurement devices. If providing comments, please 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.

We are generally seeking comment on this new petition process for BAMM.

B. Subpart A (General Provisions): Calibration Requirements

Since the rule was published on October 30, 2009, EPA has received numerous questions about the intent and extent of the equipment calibration requirements specified in 40 CFR 98.3(i). The current rule could be interpreted to require all types of measurement equipment that provide data for the GHG emissions calculations, including flow meters and "other devices" such as belt scales, to be

calibrated to a specified accuracy (*i.e.*, 5.0 percent in most cases).

The perceived universal nature of the calibration requirements in 40 CFR 98.3(i) has caused a great deal of concern in the regulated community. For example, the appropriateness of a 5.0 percent accuracy specification for a wide variety of measurement devices has been questioned. Specifically, reporters have recommended that the initial and on-going calibration requirements be modified to allow the accuracy to be determined within an appropriate error range for each measurement technology, based on an applicable standard.

Also, for small combustion units using the Tier 1 or Tier 2 CO₂ calculation methodologies in 40 CFR 98.33(a), reporters were concerned that the calibration requirements and accuracy specifications appear to apply to flow meters that are used to quantify liquid and gaseous fuel usage. This contradicts the clear statements in the nomenclature of Equations C-1 and C-2a of Subpart C that company records can be used to measure fuel consumption for Tier 1 and 2 units. We note that the definition of “company records” in 40 CFR 98.6 is quite flexible and it does not require that any particular calibration methods be used or that specific accuracy percentages be met.

In view of these considerations, we are proposing to amend 40 CFR 98.3(i) as follows, to more clearly define the scope of the calibration requirements:

(a) We are proposing to amend 40 CFR 98.3(i)(1) to specify that the calibration accuracy requirements of 40 CFR 98.3(i)(2) and (i)(3) would be 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) would continue to apply to these meters. EPA has many years of experience with fuel flow meter calibration, for example in the Acid Rain and NO_x Budget Programs, and the Agency is confident that the accuracy requirements specified in 40 CFR 98.3(i) are both reasonable and achievable for such meters. For more information please refer to the Background

Technical Support Document at EPA-HQ-OAR-2008-0508. We are also proposing to add statements to 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.

(b) We are proposing to further amend 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 would have to be calibrated to meet the accuracy requirements of the relevant subpart(s), or, in the absence of such requirements, to 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 would be documented in the written monitoring plan.

(c) We are proposing to add 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.

(d) We are proposing to add a new paragraph 40 CFR 98.3(i)(1)(iii) to specify the frequency at which subsequent recalibrations of flow meters and other measurement devices need to be performed. Recalibration would 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.

(e) We are proposing to specify the consequences of a failed flow meter calibration in a new paragraph 40 CFR 98.3(i)(7). Data would become invalid prospectively, beginning at the hour of the failed calibration and continuing until a successful calibration is completed. Appropriate substitute data

would be used during the period of data invalidation.

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

(g) We are proposing to amend 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 proposing to amend 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 would, as described below, conditionally be 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 would be 4.0 percent. If two assumed values are used and only the differential pressure transmitter is calibrated, the maximum allowable calibration error would be 2.0 percent. We note that the use of an arithmetic sum of the calibration errors is consistent with the approach in Part 75, and is designed to introduce flexibility, by allowing the results of a calibration to be accepted as valid when the calibration error of one (or in some cases, two) of the transmitters exceeds 2.0 percent. We did not intend to introduce an uncertainty analysis, such as the square root of the sum of the squares, for quantifying uncertainty.

We are also proposing to amend 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 would have to 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 could 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 would have to 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.

(h) We are proposing to amend 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 or ignition. 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 would be exempted. This proposed revision is modeled after a similar calibration exemption in section 2.1.4.1 of Appendix D to 40 CFR Part 75, for fuel flow meters that measure startup and ignition fuels. The amount of fuel used for ignition and startup generally provides a very small percentage of the annual unit heat input (less than 1 percent in most cases). Therefore, rigorous calibration of meters used exclusively for startup and ignition fuels is unnecessary. Paragraph 98.3(i)(4) would be further amended to clarify that gas billing meters are exempted from the monitoring plan and record keeping provisions of 40 CFR 98.3(g)(5)(i)(c) 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, and that maintenance records be kept for those instruments. We are proposing these changes because operation, maintenance, and quality assurance of

gas billing meters is the responsibility of the fuel supplier, not the consumer.

- (i) We are proposing to amend 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 would also be amended to clarify that the deadline for successive calibrations would be according to the a manufacturer's recommended calibration schedule or an industry consensus calibration schedule.
- (j) We are proposing to amend 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 currently allows the owner or operator to postpone the initial calibration until the next scheduled maintenance outage. The rule did not require shutdown for calibration of equipment because it was determined to be an unnecessary burden to require shutdown for calibration given that all measurement equipment required for GHG emissions would be required to be calibrated if they did not have an active calibration, necessitating a potentially large number of shutdowns.

Although the rule allows postponement of calibration, it does not specify how to report fuel consumption for the entire time period extending from January 1, 2010 until the next maintenance outage. Section 98.3(d) of subpart A allows sources to use the "best available monitoring methods" (BAMM) until April 1, 2010, and to petition the Administrator to continue using the BAMM through December 31, 2010, but not beyond that date.

In view of this, we are proposing to amend 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 proposed revision would address situations where the next scheduled outage is in 2011, or later.

C. Subpart A (General Provisions): Reporting of Biogenic Emissions

Reporters have noted that in the final Part 98 a new requirement was introduced that requires separate reporting of biogenic emissions from facilities (40 CFR 98.3(c)). They have noted that had EPA sought comment on this requirement in the proposal, they

may have commented that units subject to subpart D (Electricity Generation) should not be required to report biogenic emissions separately, as this is not currently required under Part 75, which generally established the procedures for measuring data under subpart D. Or, they may have recommended specific methods for calculating biogenic emissions from Part 75 units. Owners and operators have stated that it is not clear in Part 98 which method is required for estimating these emissions from units subject to subpart D.

EPA has subsequently provided guidance that separate reporting of biogenic emissions for units subject to subpart D is optional; however, in order to provide clarity and remove any potential inconsistencies, we are proposing revisions to subpart A and soliciting comment.

We intended that units subject to subpart D would continue to monitor and report CO₂ mass emissions as required under 40 CFR 75.13 or section 2.3 of appendix G to 40 CFR part 75, and 40 CFR 75.64. These provisions do not require separate accounting of biogenic emissions, and we did not intend to require additional accounting methods for these units under Part 98. We intended for the reporting of biogenic CO₂ emissions to be optional for units subject to subpart D. However, the current rule does not consistently affirm this. Section 98.3(c)(4) of subpart A requires sources to report facility-wide GHG emissions, excluding biogenic CO₂, and to report CO₂ emissions for each source category excluding biogenic CO₂. To meet these reporting requirements, facilities with subpart D and/or other Part 75 units on-site would have to separately account for the biogenic CO₂ emissions (if any) from those units.

To address these concerns, we are proposing to amend the data elements in subparts A and C that currently require separate accounting and reporting of biogenic CO₂ emissions so that it would be optional for Part 75 units. All units, except Part 75 units, would still be required to calculate and report biogenic CO₂ emissions separately under subpart C. We are proposing to amend the following sections of subparts A and C to reflect these changes:

- 40 CFR 98.3(c)(4)(i) would be revised to no longer require facilities to report annual emissions, *excluding* biogenic CO₂; instead, it would require all owners or operators to report annual facility-wide emissions, *including* biogenic CO₂.

- 40 CFR 98.3(c)(4)(ii) and (c)(4)(iii)(A) would be amended to state that separate reporting of biogenic CO₂ emissions is not required for units using part 75 methodologies to calculate CO₂ mass emissions.

- 40 CFR 98.3(c)(4)(ii)(B) would be revised to no longer require reporting of the annual CO₂ emissions from subparts C through JJ, *excluding* biogenic CO₂; instead, it would require reporting of the total annual CO₂ emissions for each subpart, *including* biogenic CO₂.

- 40 CFR 98.33(a)(5)(iii)(D) would be redesignated as 40 CFR 98.33(a)(5)(iv) and amended to state that separate reporting of biogenic CO₂ emissions is optional for part 75 units that qualify for and elect to use the alternative CO₂ mass emissions reporting options in 40 CFR 98.33(a)(5).

- A statement would be added to 40 CFR 98.33(e) to indicate that separate reporting of biogenic CO₂ emissions is not required for units subject to subpart D of part 98, and for part 75 units using the alternative CO₂ mass emissions reporting options in 40 CFR 98.33(a)(5). However, if the owner or operator elects to report biogenic CO₂ emissions, the methods in § 98.33(e) would be used.

- Three paragraphs of the data reporting section of subpart C, specifically 40 CFR 98.36(d)(1)(ii), (d)(2)(ii)(I), and (d)(2)(iii)(I), would be amended to reinforce that separate reporting of biogenic CO₂ emissions is optional for part 75 units.

The proposed amendments would not affect the burden for existing facilities, as existing non-Part 75 facilities were always required to calculate and report biogenic emissions separately. The amendments would simply require them to include those biogenic emissions in facility-wide and source category (subpart) totals, as opposed to subtracting them out. The proposed amendments would also address the inconsistency that appeared in Part 98 regarding separate reporting of biogenic emissions for electric generating units subject to subpart D or other units subject to Part 75, as these facilities would no longer be required to report facility emissions excluding biogenic CO₂, although they retain the option to report biogenic CO₂ separately.

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

Subpart A requires 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. The owner or operator shall retain documentation

for 3 years to support any revisions made to an annual GHG report.”

Some owners and operators have asserted that the requirements for resubmission of annual reports within 45 days of discovering an error or being notified by EPA of an error, and the requirement to correct all errors, is overly broad and could trigger a resubmission for virtually any error. They were also concerned that these requirements are made more burdensome by the fact that the data system is not yet developed, and some identified “errors” may not in fact be errors, but rather software bugs that are most likely to happen in the first year of operation of the data system. They have also observed that the regulatory requirement is more burdensome than the Acid Rain Program (ARP), which has operated for more than 15 years without such a requirement in the regulation.

We included this correction requirement in Part 98 because we determined that it is important to ensure that the most accurate data are available, in a timely fashion, for developing future GHG policies and programs. Generally, adding a requirement to resubmit data is also consistent with other EPA reporting programs, such as the ARP and the Toxic Release Inventory, as well as State and other GHG programs. While it is true that the ARP does not have a specific time requirement for resubmission in the regulation, in practice revised data have been submitted in less than 45 days after notification or identification of an error. While we maintain that it is important to retain a deadline for resubmission of the report after an error is identified in order to ensure EPA receives timely submission of data, we also recognize that certain circumstances may exist in which owners or operators cannot correct the identified errors within the 45 days. Therefore, we are proposing to amend 40 CFR 98.3(h) to clarify how a resubmission is triggered and the process for resubmitting annual GHG reports.

First, reports would only have to be resubmitted when the owner or operator or the Administrator determines that a substantive error exists. A substantive error would be 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 “errors” would not obligate the owner or operator to resubmit the annual report.

The owner or operator would be required to resubmit the report within 45 days of identifying the substantive error, or the Administrator notifying them 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 proposed change would provide owners or operators the opportunity to demonstrate that what the Administrator has deemed to be substantive errors are not, in fact, substantive errors.

Finally, we are also proposing to introduce the opportunity for owners or operators to request an extension on 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 or operators would be 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 would be granted if EPA does not respond to the extension request by the end of the 45-day period.

We are proposing 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 would 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 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.

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

Certain reporters have suggested that the recordkeeping requirements related to missing data events are overly burdensome. Specifically, 40 CFR 98.3(g)(4) of Part 98 specifies that the owner or operator must keep records of the cause and duration of each event, the actions taken to restore

malfunctioning monitoring equipment, and actions taken to prevent or minimize future occurrences. They have asserted that compared to Part 98, Part 75 requires only reporting of the cause of the missing data event and the corrective actions taken, but does not require separate accounting of the duration of the event or the actions taken to minimize occurrence in the future. They have further claimed that most missing data events associated with the use of continuous emissions monitors are due to routine activities or calibration failures for which there are no clear measures to avoid similar occurrences in the future. Therefore, according to the owners and operators, the final recordkeeping requirements are overly burdensome and add little value.

After reviewing these requirements, we agree with the claims and we are proposing to amend 40 CFR 98.3(g)(4) by requiring that records be kept of only the cause of each missing data event and the corrective actions taken. We have concluded that this information is sufficient for operating the program and that making this change will reduce the reporting burden for all reporters. This proposed revision would make the Part 98 recordkeeping provisions for missing data events consistent with those in 40 CFR Part 75 (specifically 40 CFR 75.57(h)). We further propose to clarify 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.

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

We are proposing several amendments to subpart A, as follows. We are proposing to amend 40 CFR 98.3(c)(1) by adding a requirement to report a facility or supplier ID number. We expect to receive GHG emissions data in electronic format from thousands of facilities and suppliers. Therefore, a unique ID number must be assigned to each facility or supplier, for administrative purposes, to facilitate program implementation. This approach has worked well in other EPA programs that require electronic data reporting from large numbers of facilities (e.g., the Acid Rain and NO_x Budget Programs). The exact mechanism for assigning the ID numbers has not yet been determined. EPA will provide the necessary guidance later this year.

We are proposing to amend 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 proposing to add the same element to the delegation by designated

representative and alternate designated representative under 40 CFR 98.4(m)(2). This information will help EPA and reporting system users to correctly identify persons during the designated representative appointment or agent delegation process. Part 98 and the proposed amendments would not require the designated representative, alternate designated representative or agent to be an employee of the reporting entity. When a designated representative further delegates their authority to an agent, the agent would gain access to all data for that facility or supplier. To underline the importance of granting access to the correct person, EPA would require the designated representative (or alternate) to confirm each agent delegation. Adding organization name to the certificate of representation and notice of delegation will add a level of assurance to the confirmation process.

We are proposing to amend 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. This amendment is proposed because in order to incorporate additional fluorinated GHGs not listed in Table A-1 into the supplier's total GHG emissions in mtCO_{2e}, the reporter would be required to propose a GWP for the gas or use an established factor developed by the Intergovernmental Panel on Climate Change or another entity. EPA does not believe it is necessary to require reporters to develop a GWP for these gases at this time. Further, it is important to note that these gases would still be required to be reported under 40 CFR 98.3(c)(5)(ii) (in metric tons of GHG). Therefore, EPA could calculate mtCO_{2e} emissions from these gases in the future as GWP's become available or are updated.

Finally, we are proposing to amend 40 CFR Part 98.6 (Definitions) and 40 CFR Part 98.7 (What Standardized Methods are Incorporated by Reference into this Part?). We are proposing to add or change several definitions to Subpart A, which are needed to clarify terms used in other subparts of Part 98. Similarly, we are proposing to amend 40 CFR 98.7 (incorporation by reference) to accommodate changes in the standard methods that are allowed by other subparts of the rule.

We are proposing to amend 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 proposing to amend 40 CFR 98.3(f) to correct the cross-reference from “§ 98.3(c)(8)” to “§ 98.3(c)(9).”

We are proposing to amend the definitions of several terms in 40 CFR 98.6:

- Bulk Natural Gas Liquid,
- Distillate fuel oil,
- Fossil fuel,
- Mscf,
- Municipal solid waste or MSW, and
- Natural gas.

Bulk Natural Gas Liquid. Owners and operators have objected to the definition of “bulk natural gas liquid or NGL.” Section 98.6 in subpart A defines “bulk natural gas liquid or NGL” as a product which “refers to mixtures of hydrocarbons that have been separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities.” The owners and operators have requested we remove the phrase “or other methods at lease separators and field facilities” from the above definition. They assert that these processes are not simple separation processes, but rather, NGL extraction processes that are typically performed at “gas plants” and not at “lease separators and field facilities.”

We agree that the separation processes listed in the definition of “bulk natural gas liquid or NGL” are associated with gas plants, and not lease separators and field facilities. It was not EPA's intent to require the reporting of emissions associated with these processes at lease separators and field facilities. In fact, in 40 CFR 98.400, we specifically state that the supplier category consists only of natural gas liquids fractionators and local natural gas distribution companies. Under 40 CFR 98.400(c), we specify that field gathering and boosting stations, as well as natural gas processing plants that “separate NGLs from natural gas * * * but do not fractionate these NGLs into their constituent products” do not meet the source category's definition.

Therefore, we are proposing to strike “lease separators and field facilities” from the definition of “bulk natural gas liquid or NGL,” as well as from the definition of “natural gas liquids (NGL)” for enhanced clarity. However, we have determined that the words “or other methods” should remain in the above definition because the list of separation processes listed in the definition (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 proposing to expand the definition of “Distillate fuel oil” to include kerosene-type jet fuel.

Fossil Fuel. Some reporters have noted that the proposed rule set forth the same definition of “fossil fuel” that applies in the New Source Performance Standards program: “Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat” (74 FR 16621).

However, the final Part 98 includes the following definition, which, according to certain Parties, has no precedent in Clean Air Act (CAA) regulations: “Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.”

These owners and operators have asserted that the public did not have sufficient opportunity to comment on these changes, which together, they claimed, re-classify municipal solid waste (MSW) and tires as fossil fuel and could set an unintended precedent for other CAA programs. Further, they claimed that EPA changed the designation of MSW and tires from being classified as “alternative fuels” in the proposal to being classified as “fossil fuel-derived fuels (solid)” in the final Part 98.

We did not intend to “re-classify” MSW and tires between the proposal and final Part 98 in any meaningful way. Rather, any changes made were due to the overall restructuring of the General Stationary Fuel Combustion source category in response to comments and were intended to expand the use of Tier 1 and Tier 2, and to remove some requirements that would subject units to Tier 3. Based on the above concerns, however, it has become apparent that stakeholders believe the changes had unintended consequences. Therefore, we have reevaluated this issue and are proposing amendments to the classification of fuels in Table C–1, as well as the definition of fossil fuel. We note that overall we do not believe that the changes between the proposed and final Part 98, nor the amendments described below, have a substantive impact on the calculation requirements or the reporting of emissions for MSW or tires under this rule.

We made several changes from proposal in Part 98 in response to comments about use of the Tiers. In

subpart C, in order for facilities to use Tier 1 or Tier 2, the fuel combusted had to be included in Table C–1. MSW and tires were not included in Table C–1; rather they were included in the proposed Table C–2, which was generically labeled “alternative fuels.” The restructuring of the Tiers in subpart C necessitated moving all fuels for which Tier 1 and Tier 2 were allowed into Table C–1. Table C–1 labeled these fuels as “fossil fuel-derived” to reflect the methods used to calculate emissions, noting the related provisions for determining the biogenic portions of fuels in subpart C.

In order to address the above concerns raised with subpart C, we are now proposing to change the heading for these fuels from “fossil fuel-derived” to “Other fuels (solid)” in Table C–1.

Further, we are proposing to amend the definition of fossil fuel to return to the initial proposed definition. After proposal, we altered the definition in subpart A intending to provide clarity to facilities subject to Subpart C in the reporting of CO₂ emissions per the requirements of 40 CFR 98.36, specifically, intending to clarify what was meant in the proposed definition by “ * * * solid, liquid, or gaseous fuel derived from such materials.” We also changed the definition in subpart A to better align the definition of fossil fuel with the definition of the general stationary fuel combustion sources in 40 CFR 98.30 (*i.e.*, “devices that combust solid, liquid, or gaseous fuels, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible materials”).

We believe that the definition included in subpart A may have not added the clarity expected and that the definition of general stationary fuel combustion sources provided in subpart C is sufficient. We are soliciting comment on the proposed changes in the definition of fossil fuel in subpart A in the context of the calculation methods provided for these fuels in subpart C, and ask commenters to provide additional information if they believe that emissions from combusting these fuels should be estimated differently.

Mscf. We are proposing to amend the definition of “Mscf” in 40 CFR 98.6 to indicate that “Mscf” means thousand standard cubic feet, and not, as incorrectly noted in the final rule, a million standard cubic feet.

Municipal Solid Waste. We have received many questions regarding the definition of “Municipal solid waste or

MSW” in Part 98. Specifically, the brevity of the definition makes it difficult to determine whether certain types of waste constitute MSW. We are proposing to amend the definition to closely match the definition of “municipal solid waste” in Subpart Ea of the NSPS regulations (40 CFR 60.51a). The amended definition would explain what is meant by “household waste,” “commercial/retail waste,” and “institutional waste.” It would also provide a comprehensive list of materials that are excluded from these categories (*e.g.*, industrial process or manufacturing wastes and medical waste).

Natural Gas. We have also received many questions indicating that the definition of “Natural gas” is too inclusive and in some respects counterintuitive. The current definition begins with a statement that natural gas is a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found beneath the earth’s surface. However, it ends by equating “process gas” and “fuel gas” (neither of which is a naturally occurring gas mixture) with natural gas. We are proposing to amend the definition of “Natural gas” in 40 CFR 98.6 to be consistent with definitions found in 40 CFR Parts 60 and 75. The amended definition would remove the references to process gas and fuel gas, and would specify that natural gas must be at least 70 percent methane or have a high heat value between 910 and 1150 Btu/scf.

We are proposing to add definitions of the following terms to 40 CFR 98.6 due to the large number of questions received requesting clarification of the definition of these terms:

- Agricultural byproducts,
- Primary fuel,
- Solid byproducts,
- Waste oil, and
- Wood residuals.

The terms “Agricultural byproducts,” “Solid byproducts,” and “Wood residuals” are used to describe three types of solid biomass fuels listed in Table C–1 of Subpart C, but they are not defined in 40 CFR 98.6. The proposed definitions are based on the results of an Internet search and IPCC inventory guidelines (*see* EPA–HQ–OAR–2008–0508). For the purposes of Part 98, “Agricultural byproducts” would include the parts of crops that are not ordinarily used for food (*e.g.*, corn straw, peanut shells, pomace, etc.). “Solid byproducts” would include plant matter such as vegetable waste, animal materials/wastes, and other solid biomass, except for wood, wood waste and sulphite lyes (black liquor). “Wood residuals” would include waste wood

recovered primarily from MSW streams, construction and demolition debris, and primary timber processing. Wastewater process sludge generated at pulp and paper mills would also be included; however, we are soliciting comment on whether the default emission factors for wood and wood residuals are appropriate for paper mill wastewater sludge, and, if not, what those emission factors should be.

“Primary fuel” would be defined as the fuel that contributes the greatest percentage of the annual heat input to a combustion unit. “Waste oil,” which we are proposing to add to Table C–1 as a new fuel type, would be defined as oil whose physical properties have changed, either through storage, handling, or use, so that the oil can no longer be used for its original purpose. Waste oil would include both automotive and industrial oils of various types.

G. Subpart C (General Stationary Fuel Combustion)

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 proposed 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 to calculate weighted annual average HHV.
- 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 units with CEMS.
- Use of Tier 3.
- Tier 4 requirements for units that combust greater than 250 tons of MSW per day.
- Applicability of Tier 4 to common stack configurations.
- Starting dates for the use of Tier 4.
- CH₄ and 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.
- CO₂ emissions from blended fuel combustion.
- Use of consensus standard methods.
- CO₂ monitor span values.
- CEMS data validation.
- Use of 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 proposing to add a 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. Section 98.30(a) of subpart C defines a stationary fuel combustion source as a device that combusts “ * * * solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter * * * ”. A pilot light is a small permanent 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 to provide useful energy to an industrial process, or to reduce waste by removing combustible matter. Therefore, we are clarifying that, for the purposes of Part 98, a pilot light is not considered to be a stationary fuel combustion source and pilot gas consumption would not be required to be included in the GHG emissions calculations.

GHGs to Report. We are proposing to amend 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 proposing to amend 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 proposing to amend this paragraph 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 Clean Air Act program. Paragraph 98.33(a) would also be 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. Subpart C of Part 98 allows the use of fuel billing records to quantify natural gas consumption, for the purposes of calculating CO₂ mass

emissions. On the billing records provided by natural gas suppliers, fuel usage is often expressed in units of “therms,” rather than standard cubic feet (scf). A therm is equal to 100,000 Btu, or 0.1 mmBtu. Therefore, the equations for calculating CO₂ mass emissions in Subpart C (e.g., Equation C–1), which require fuel usage to be in units of scf, are not suitable when fuel consumption is expressed in therms.

In view of this, we are proposing to amend 40 CFR 98.33(a)(1) by adding a new equation, C–1a, to Tier 1. When natural gas consumption is expressed in therms, equation C–1a would enable 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 proposing to allow 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), would be added to 40 CFR 98.33 to reflect this. Section 98.36(e)(2)(i) would also be amended to allow gaseous fuel consumption to be reported in units of therms.

Use of Equation C–2b. Whenever HHV data are received on a monthly or more frequent basis, the Tier 2 CO₂ emissions calculation methodology requires the owner or operator to use Equation C–2b to calculate the annual average HHV, weighted according to monthly fuel usage. The fuel-weighted annual average HHV is then substituted into Equation C–2a. If HHV data are received less frequently than monthly, an arithmetic average HHV is used in the emissions calculations (see 40 CFR 98.33(a)(2)(ii)).

However, we have learned that in cases where a facility includes part 75 units (i.e., boilers and/or combustion turbines) and small combustion sources such as space heaters that share a common natural gas or oil supply, the use of Tier 2 may be triggered for the small combustion sources when the part 75 units use the appendix D methodology to quantify heat input. This is because appendix D of Part 75 requires periodic sampling of the heating value of fuel oil and natural gas. Tier 2 will be triggered for the small combustion units if the Part 75 fuel sampling frequency is equal to or greater than the minimum frequency specified in § 98.34(a). Further, if the part 75 fuel sampling frequency is monthly or greater, Equation C–2b would have to be used to calculate fuel-weighted annual average HHVs for the small combustion sources.

Requiring small, low-emitting combustion sources to calculate CO₂

mass emissions using fuel-weighted annual average HHVs instead of arithmetic average values will not significantly enhance data quality. In view of this, we are proposing to amend 40 CFR 98.33(a)(2)(ii), to require calculation of a weighted HHV 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 § 98.36(c)(1) in which all units in the group are smaller than 100 mmBtu/hr, the annual arithmetic average HHV, rather than the annual fuel-weighted average HHV, would be used in Equation C-2a.

Categories of Gaseous Fuels. Section 98.34(a)(2)(iii) of subpart C requires quarterly HHV sampling for liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas, when the Tier 2 methodology is used to calculate CO₂ mass emissions. The term “fossil fuel-derived gaseous fuels” has caused considerable confusion among regulated sources. The nomenclature and organization of Table C-1 of Subpart C makes it hard to determine which fuels are included in this category. Currently, only two fuels are listed in Table C-1 under the heading of fossil fuel-derived gaseous fuels: blast furnace gas and coke oven gas. However, a number of other gaseous fuels that are derived from petroleum, such as butane, are not listed there, but are listed under a different heading for “petroleum products.”

We are proposing to revise 40 CFR 98.33(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 would also be made to Table C-1 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) currently allows flow meters that measure mass flow rates of liquid fuels to be used to quantify fuel consumption, provided that the density of the fuel is determined and the measured mass of fuel is converted to units of volume (*i.e.*, gallons), for use in Equation C-4. In response to a number of requests, we are proposing to amend 40 CFR 98.33(a)(3)(iv), to conditionally allow flow meters that measure mass flow rates of gaseous fuels to be used for Tier 3 applications. To use mass flow meters, the density of the gaseous fuel would

have to be measured, 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. The Tier 4 calculation methodology in 40 CFR 98.33(a)(4) requires a CO₂ CEMS to be used together with a stack gas flow rate monitor to measure CO₂ mass emissions. If the CO₂ monitor measures on a dry basis, corrections for the stack gas moisture content are needed, because the flow monitor measures on a wet basis.

Part 98 currently requires that the moisture corrections be made either by installing a continuous moisture monitoring system or by using a default moisture value from 40 CFR Part 75 (specifically 40 CFR 75.11(b)(1)) in the calculations. However, the default moisture constants from Part 75 only apply to various grades of coal, and to wood and natural gas.

Recently, we have received inquiries from a number of sources that currently have dry-basis CO₂ monitors in place and are required to use Tier 4. These sources have requested that EPA allow the use of site-specific default moisture values, in cases where no applicable default value is specified in Part 75 for the type(s) of fuel(s) combusted, or where the Part 75 moisture values are believed to be unrepresentative.

EPA has approved many petitions for site-specific moisture content default values under the ARP. Therefore, we believe it is reasonable to allow Part 98 sources to develop such default values, using an approach similar to the one that has been approved under the ARP.

In view of this, we are proposing to amend 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) would have to represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and would have to account for any distinct difference(s) in stack gas moisture content associated with different process operating conditions.

For each site-specific default moisture percentage, at least nine runs would be required using EPA Method 4—Determination Of Moisture Content In Stack Gases (40 CFR Part 60, Appendix A-3). Moisture data from the relative accuracy test audit (RATA) of a CEMS could be used for this purpose. Each site-specific default moisture value would be calculated by taking the arithmetic average of the Method 4 runs.

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

Determining Emissions from an Exhaust Stream Diverted from a CEMS Monitored Stack. We are proposing to amend 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 paragraph is intended to address situations where a portion of the stack gas generated by the Tier 4 unit is diverted for the purpose of drying fuels, recovering heat, or some other process-related activity. The provisions of the new paragraph would not apply when CO₂ is removed or chemically altered in a way that significantly changes the CO₂ concentration at the outlet of the unmonitored stack, compared to the outlet CO₂ concentration at the stack equipped with a CEMS. The owner or operator would be required to use the best available information to estimate the hourly stack gas volumetric flow rates exhausting through the unmonitored stack. Best available information would include, but would not be limited to, correlation of operating parameters with flow rate, periodic flow rate measurements made with EPA Method 2, engineering analysis, etc. The estimated flow rates of the diverted gas stream would be made at the point where the diverted stream exits the main flue gas exhaust system. Each hourly volumetric flow rate value used in Equation C-6 of Subpart C would be the sum of the flow rate measured at the stack equipped with a CEMS and the estimated flow rate of the diverted gas stream. All procedures used to estimate the volumetric flow rate of the diverted gas stream would be documented in the monitoring plan required under 40 CFR 98.3(g)(5).

Biomass Combustion in Units With CEMS. We are proposing to amend 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). As discussed above in section II.C of the preamble, we are also proposing to amend 40 CFR 98.3(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 Part 75 methodologies to calculate CO₂ mass emissions, as described in 40 CFR 98.33(a)(5)(i) through (a)(5)(iii). As discussed above, separate reporting of biogenic CO₂ emissions is also optional for units subject to subpart D.

Use of Tier 3. Section 98.33(b)(3)(iii) of subpart C currently requires the use of Tier 3 when a fuel that is not listed in Table C-1 of Subpart C is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr, if two conditions are met: (a) The use of Tier 4 is not required; and (b) the fuel provides at least 10 percent of the annual heat input to the unit.

However, 40 CFR 98.33(b)(3)(iii)(B) refers to the annual heat input to a group of units served by a common supply pipe, in addition to the heat input to an individual unit. The text of 40 CFR 98.33(b)(3)(iii) is not consistent with 40 CFR 98.33(b)(3)(iii)(B) because it does not mention common pipe configurations.

We are proposing to amend 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.

The Agency also proposes to add 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 fuel type or unit size. For example, Subpart Y requires certain units that combust refinery fuel gas (RFG) 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 Requirements for Units That Combust Greater Than 250 Tons of MSW per Day. Owners and operators of units that combust municipal solid waste have contended that, because Part 98 requires that units that combust MSW must follow Tier 4 if they meet the requirements in 40 CFR 98.33(b)(4)(ii) or 40 CFR 98.33(b)(4)(iii), it entails a disproportionate burden for municipal waste combustors (MWCs). One element of their argument was that a threshold of greater than 250 tons per day of MSW was a more stringent threshold than the 250 mmBtu/hr heat input threshold for other stationary combustion units and, therefore, a disproportionate burden for MWCs. Further, they stated that the industry did not have the necessary emission monitoring equipment in place and would, therefore, be required to install

new equipment in order to meet the requirements of the rule.

Part 98 included a threshold of 250 tons of MSW per day because it was consistent with the threshold applied in the EPA New Source Performance Standards (NSPS). Under that program, units combusting greater than 250 tons per day of MSW are considered “large” units. We did not believe that subpart C applied a disproportionate burden to municipal waste combustors because all “large” units (whether 250 tons of MSW per day or with a heat input capacity greater than 250 mmBtu/hr) would only be subject to Tier 4 if they met the other conditions outlined in 40 CFR 98.33(b)(4). We have reevaluated this issue based on the fact that while a threshold of 250 tons of MSW may be appropriate for the purposes of NSPS, it is not necessarily appropriate for a GHG emissions reporting program. We also recognize that a large majority of the units may have to install either a flow meter or a concentration monitor, and in some cases both, to comply with subpart C.

Based on these concerns, we are proposing to amend 40 CFR 98.33(b)(4)(ii)(A) to change the 250 tons MSW per day threshold to 600 tons MSW per day, based on further analysis that this value is approximately equivalent to the 250 mmBtu/hr heat input requirements for other large stationary combustion units. For more information, please refer to the Background Technical Support Document (EPA-HQ-OAR-2008-0508). Units less than 600 tons MSW per day, that do not meet the requirements in 40 CFR 98.33(b)(4)(iii) could use Tier 2. We believe that this proposal still meets the desired goal to obtain high quality data from larger units, while not applying unnecessary burden. With this proposed amendment, MWCs would be subject to comparable monitoring thresholds and conditions as other general stationary combustion units.

Applicability of Tier 4 to Common Stack Configurations. Section 98.36(c)(2) of Subpart C allows the owner or operator of stationary combustion units that share a common stack (or duct) and use the Tier 4 methodology to calculate CO₂ mass emissions to continuously monitor and report the combined CO₂ mass emissions at the common stack (or duct), in lieu of separately monitoring and reporting the CO₂ emissions from the individual units.

Several other Subparts of Part 98 either: (1) Allow a particular process or manufacturing unit to use Tier 4 to quantify CO₂ mass emissions, as an alternative to using a mass balance

approach (for instance, Subpart G allows this option for an ammonia manufacturing unit—see 40 CFR 98.73(a) and (b)); or (2) require Tier 4 to be used in certain instances when a process unit and a stationary combustion unit share a common stack (e.g., see 40 CFR 98.63(g) and 98.73(c)).

Subpart C sets forth the applicability of Tier 4 in 40 CFR 98.33(b)(4)(ii) and (b)(4)(iii). However, note that 40 CFR 98.33(b)(4) focuses exclusively on individual stationary fuel combustion units; no mention is made of common stack configurations.

In view of this, we are proposing to amend 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) would be 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) would also be 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 would apply if:

- 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); and
- 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 would also apply when all of the combustion units in the configuration are small (≤ 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 would be 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 would be 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 could 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 would have to be monitored at the common stack or duct, using Tier 4.

Starting Dates for the Use of Tier 4. Section 98.33(b)(5) of subpart C currently 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. Recently, a number of sources have asked EPA whether Tier 4 may be used prior to January 1, 2011 if the required CEMS are certified some time in 2010, or whether Tier 2 or Tier 3 must be used for the entire year.

We believe that it is reasonable for sources to begin reporting CO₂ emissions data prior to 2011 from CEMS that successfully complete certification testing in 2010. Therefore, we are proposing to amend 40 CFR 98.33(b)(5) accordingly. 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)).

The proposed revisions would 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. CEMS data recorded during the certification test period could also be used for Part 98 reporting, provided that: (a) All required certification tests are passed in sequence, with no test failures; and (b) no unscheduled maintenance or repair of the CEMS is required during the test period.

We are also proposing to amend 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: (1) The primary fuel, (2) the manner of unit operation, or (3) the installed continuous monitoring equipment. In such cases, the owner or operator would be required to begin using Tier 4 no later than 180 days from the date on which the change is implemented. This would allow 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. The equations for calculating CH₄ and N₂O emissions from stationary combustion sources are found in 40 CFR 98.33(c). Calculation of these emissions is required only for fuels listed in Table C-2 of Subpart C. When either the Tier 1 or the Tier 3 methodology is used to determine CO₂ mass emissions, Equation C-8 is used to calculate CH₄ and N₂O emissions. Equation C-8 includes the term “HHV,” which is defined as the applicable default high heat value (HHV) from Table C-1 for a particular type of fuel. Owners and operators have asserted that they should be able to use actual HHV data for Tier 3 units, in lieu of using the Table C-1 default values, and noted that site-specific values would be more accurate.

We agree that this would result in more accurate estimates of emissions and are proposing to revise the definition of the term “HHV” in the Equation C-8 nomenclature. The proposed amendment would allow Tier 3 units to use actual HHV data to calculate CH₄ and N₂O emissions. If multiple HHV values are obtained during the year, the arithmetic average would be used in Equation C-8.

Units that monitor heat input year-round according to 40 CFR Part 75 or that use the Tier 4 CO₂ calculation methodology are required to use Equation C-10 in Subpart C to calculate CH₄ and N₂O emissions. When more than one type of fuel listed in Table C-2 is combusted in these units during normal operation, 40 CFR 98.33(c)(4)(ii) requires Equation C-10 to be used separately for each fuel.

Owners and operators have asked EPA to clarify what is meant by “normal operation,” and whether any fuel(s) should be excluded from the emissions calculations. Today’s proposed amendments would clarify the Agency’s intent by removing the term “normal operation” from 40 CFR 98.33(c)(4)(i) and (c)(4)(ii). Therefore, calculation of CH₄ and N₂O emissions would simply be required for each Table C-2 fuel

combusted in the unit during the reporting year.

We are also proposing to further amend 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. For all multi-fuel units that use CEMS to comply with Part 98, subpart C requires the “best available information” to be used to determine the percentage of the annual unit heat input contributed by each type of fuel, for the purposes of calculating CH₄ and N₂O mass emissions.

For part 75 units that use CEMS to quantify unit heat input, the fuel-specific annual heat input values needed for the CH₄ and N₂O emissions calculations can, in most cases, be determined from information in the part 75 electronic data reports—specifically, from the “F-factors” reported for each unit operating hour. These F-factors, which are fuel-specific, are used in the hourly heat input calculations. Therefore, it is possible to use the reported F-factors to group the annual unit operating hours according to fuel type, and to sum the reported hourly heat input values for each group. However, if the owner or operator elects to use the reporting option in section 3.3.6.5 of part 75, appendix F, the fuel-specific heat input values cannot be determined from the emissions reports. This is because section 3.3.6.5 of appendix F allows the owner or operator to calculate all hourly heat input values using the “worst-case” (highest) F-factor for any fuel combusted in the unit. A situation where this reporting option is likely to be implemented is for a coal-fired utility boiler that uses small amounts of natural gas for unit startup. A second example where the worst-case F-factor option is sometimes used is for a unit that combusts a blend of bituminous coal and sub-bituminous coal, in varying proportions. The F-factors for these two grades of coal are nearly the same. For the examples cited, the impact on the reported annual unit heat input is generally very small (1 to 2 percent at most). In view of this, we are proposing to allow part 75 units that use the worst-case F-factor reporting option to 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), and we are proposing to allow 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 directly from the part 75 electronic data reports.

Carbon Dioxide Emissions from Sorbent. Section 98.33(d) of subpart C currently requires the following sources to use Equation C–11 to calculate and report CO₂ mass emissions from sorbent, except where the total CO₂ emissions are measured using CEMS: (a) Fluidized bed combustion units; (b) units with wet flue gas desulfurization (FGD) systems; and (c) units equipped with “other acid gas emission controls with sorbent injection.” Equation C–11 includes the term “R,” which is defined as “1.00, the calcium to sulfur stoichiometric ratio.”

Industry members have noted that some sorbents that reduce acid gas emissions do not produce CO₂ (for instance, Ca(OH)₂ does not). Further, the 1.00 value of R in Equation C–11 applies only to SO₂ removal, indicating that one mole of CO₂ is produced for every mole of SO₂ removed. We have also been informed that CO₂-producing sorbents such as sodium bicarbonate are sometimes injected to remove other acid gas species (e.g., HCl).

In view of these considerations, we are proposing to amend 40 CFR 98.33(d) by making it more generally applicable to different types of CO₂-producing sorbents. The term “R” would be 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 would be 1.00. For other CO₂-producing sorbents, a specific value of R would be 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. In response to questions about the methodologies in 40 CFR 98.33(e) for calculating biogenic CO₂ mass emissions from biomass combustion, we are proposing a number of technical corrections and clarifications to that section of the rule.

The title and introductory text of 40 CFR 98.33(e) would be amended to more precisely define the requirements for reporting biogenic CO₂ emissions. In general, biogenic CO₂ emissions reporting would be 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 proposing to amend 40 CFR 98.33(e) to describe three cases in which units that combust biomass

would not need to report biogenic CO₂ emissions separate from total CO₂ emissions:

1. If a biomass fuel is not listed in Table C–1, the biogenic CO₂ emissions would need to be reported separately from total CO₂ emissions only if:
 - 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; and
 - The unit does not use CEMS to quantify its annual CO₂ mass emissions.

In that case, according to 40 CFR 98.33(b)(3)(iii), Tier 3 would have to 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 reporting of biogenic CO₂ emissions would be optional.

3. For the combustion of tires, which are also partly biogenic (typically 10–20 percent biomass, for car and truck tires), separate reporting of the biogenic CO₂ emissions would be optional, but could be done following provisions in 40 CFR 98.33(e).

We are proposing to amend 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. There is no technical basis for this restriction, provided that biomass consumption can be accurately quantified. However, the use of Tier 1 would not be allowed for combustion of MSW, as originally specified in 40 CFR 98.33(e)(1) of subpart C, and would also not be allowed for the combustion of tires, if biogenic CO₂ emissions are calculated for tires.

We are proposing to amend the methodology in 40 CFR 98.33(e)(2), which is specifically for units using a CEMS to measure CO₂ mass emissions, by:

1. 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
2. Prohibiting its use if the unit combusts MSW or tires.

Section 98.33(e)(2) of subpart C currently requires the total volume of CO₂ produced from fossil fuel combustion (which is based on estimated fuel usage, measured HHVs and F-factors) to be subtracted from the total volume of CO₂ from the

combustion of all fuels (as determined from the CEMS data). The difference is assumed to be the volume of biogenic CO₂. However, this approach is only viable if all of the CO₂ emissions are from the combustion of fossil fuels and biomass, and if no fuels (such as MSW and tires) that are a mixture of biomass and fossil fuel derivatives are combusted in the unit.

If there are any process CO₂ emissions or CO₂ emissions from sorbent in the stack effluent, the volumes of those CO₂ emissions would have to be subtracted from the total volume of CO₂ derived from the CEMS data in order to determine the biogenic CO₂ volume.

Further, if any partly biogenic fuels (such as MSW and tires) are combusted in the unit, the fossil component of each of these fuels would have to be characterized. We are not aware of any method that is economically feasible for reporting sources to determine the mass percentage of the fossil fuel component of fuels such as MSW and tires. In addition, we are not aware of any practical method for quantifying CO₂ volumes from sorbent or from non-combustion industrial processes. For these reasons, we are proposing restrictions “1” and “2” above on the use of the methodology in 40 CFR 98.33(e)(2).

For sources that are combusting MSW, we are proposing to amend 40 CFR 98.33(e)(3) to require the use of ASTM methods D7459–08 and D6866–08 quarterly, 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 proposing to further amend 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.

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

Finally, we are proposing to amend 40 CFR 98.33(e)(5) so that it would also

apply 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 would apply when HHV data for a biomass fuel are available at the minimum frequency specified in 40 CFR 98.34(a)(2).

Fuel Sampling for Coal and Fuel Oil. We are proposing to amend 40 CFR 98.34(a)(2), to clarify the frequency at which the HHV needs to be determined for different types of fuels.

In subpart C, the Tier 2 calculation methodology in 40 CFR 98.33(a)(2) requires periodic fuel sampling and analysis to determine HHVs. Section 98.34(a)(2) specifies the minimum required sampling frequency for various fuel types. For coal and fuel oil, at least one representative sample must be obtained and analyzed for each fuel lot. A “fuel lot” is defined as a shipment or delivery of a particular type of fuel, and may consist of a ship load, a barge load, a group of trucks, or a group of railroad cars.

Several reporters have noted that some facilities receive fuel deliveries by truck, rail or pipeline quite frequently—even daily in some cases. The reporters have expressed the concern that, under subpart C, daily fuel deliveries appear to trigger a requirement for daily sampling and analysis, according to the definition of a fuel lot. Reporters have also noted that coal and petroleum derivatives such as coke and petroleum coke are often delivered in lots. Further, the Agency has received inquiries asking why a commonly-used fuel oil sampling strategy is not included in subpart C, *i.e.*, taking a sample whenever oil is added to the storage tank.

It is not our intent to require an excessive amount of HHV sampling for coal and fuel oil (or for any other solid or liquid fuel that is delivered in lots), or to prohibit the use of viable sampling options. Therefore, we are proposing, first, to amend 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 proposing to more precisely define the term “fuel lot” in 40 CFR 98.34(a)(2)(ii), as it pertains to facilities that receive multiple deliveries of a particular fuel from the same supply source each month, either by truck, rail, or pipeline. The proposed amendment would clarify that a fuel lot consists of all of the deliveries for a given calendar month. Thus, for these

facilities, the required HHV sampling frequency would be no greater than once per month. We are proposing to add 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 proposed revisions to 40 CFR 98.34(a)(2)(ii).

Third, we are proposing to further revise 40 CFR 98.34(a)(2)(ii) and 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 would also be allowed.

Tier 3 Sampling Frequency for Gaseous Fuels. Section 98.34(b)(3)(ii) of subpart C specifies the minimum required frequency for determining the carbon content and molecular weight of various types of fuel, when using the Tier 3 methodology to calculate CO₂ mass emissions. For gaseous fuels, daily sampling is required if “the necessary equipment is in place to make these measurements.” Otherwise, weekly sampling is required.

EPA has received a number of questions from owners and operators about the meaning of “necessary equipment.” In particular, sources have asked whether this refers only to continuous, on-line equipment such as gas chromatographs, or whether daily, manual sampling is required where such capability exists.

We are proposing to amend 40 CFR 98.34(b)(3)(ii)(E) to clarify that daily sampling of gaseous fuels for carbon content and molecular weight is only required where continuous, on-line equipment is in place; weekly sampling would be required in all other cases. This has always been the Agency’s intent.

CO₂ Emissions From Blended Fuel Combustion. One of the most frequently asked questions by the regulated community since the October 30, 2009 publication of 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. First, 40 CFR 98.34(a)(3) stated that when different types of fuel are blended (*e.g.*, different ranks of coal or different grades of fuel oil), two options could be used for determining the HHV for Tier 2 applications: (a) Use a weighted HHV in the emissions calculations; or (b) take a representative sample of the blend and analyze it for HHV. Second, 40 CFR 98.34(b)(3)(v) stated that these same two options apply to carbon content and molecular weight determinations under Tier 3. Third, for Tier 3 common pipe applications, 40 CFR 98.34(b)(1)(vi) required that fuels

either be metered individually before blending, or that the blended fuel and a subset of the individual fuels be metered so that the volume of each fuel in the blend can be determined.

Based on the number of questions received, we have concluded that these rule provisions do not adequately address the complexities associated with blended fuels. Therefore, we are proposing substantive amendments to 40 CFR 98.34(a)(3), (b)(1)(vi), and (b)(3)(v). The proposed amendments would 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 would be calculated separately. In the latter case, we are proposing that the blend be considered to be a distinct “fuel type,” and that its mass or volume and essential properties (*e.g.*, HHV, carbon content, etc.) be measured 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 would be as follows. For smaller combustion units (heat input capacity not more than 250 mmBtu/hr), we are proposing that Tier 2 (or possibly Tier 1) 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 would be calculated, using proposed Equation C–16. For Tier 1 applications, a heat-weighted default HHV would also have to be determined, using proposed 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 would be 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 would be 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 proposed 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, we are proposing that the owner or operator would use Tier 3 to calculate the CO₂ mass emissions from combustion of a blended fuel. The mathematics for Tier 3 would be much 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 would be 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 would be 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 proposing to add a new paragraph, (c)(6), to 40 CFR 98.33. Calculation of CH₄ and N₂O emissions would be 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) would 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 would be required, based on the best available information, and the procedures in 40 CFR 98.33(c)(6)(ii) would be followed. First, the annual consumption of each component fuel in the blend would be 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 would be 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 would 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 would be summed across all components, and these sums would be reported as the annual CH₄ and N₂O mass emissions for the blend.

Use of Consensus Standard Methods. Sections 98.34(a)(6), (b)(4), and (b)(5) of subpart C specify acceptable methods for determining fuel HHV, carbon content, and molecular weight, and methods for calibrating fuel flow meters. The methods listed in those sections are from consensus standards organizations such as ASTM, ASME, AGA, and GPA. Although we attempted to assemble a comprehensive list of methods and provide appropriate alternatives, it is possible that other valid methods from these organizations and practices have been overlooked, or that in some cases, industry consensus standard methods may be more appropriate than the methods listed. In view of this, we are proposing to remove the specific method lists from 40 CFR 98.34 and to amend 40 CFR 98.34(a)(6) and (b)(1)(i)(A), delete paragraph (b)(4), redesignate paragraph (b)(5) as (b)(4), and amend newly designated paragraph (b)(4). These proposed amendments would allow the owner or operator to either: (1) Use appropriate methods published by consensus standards organizations such as ASTM, ASME, API, AGA, ISO, etc.; or (2) use industry standard practice. The methods used would 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. For example, a typical span value for a CO₂ monitor installed on a coal-fired boiler is 20

percent CO₂; therefore, the CGA concentrations represent 25 to 40 percent of span and 50 to 70 percent of span. 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 proposing to amend 40 CFR 98.34(c) by adding a new paragraph (c)(6), which would allow the CGAs 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. The Tier 4 methodology in 40 CFR 98.33(a)(4) requires the use of CEMS to measure CO₂ mass emissions. For each unit operating hour, the CO₂ mass emissions are determined using either valid CEMS data or appropriate substitute data values when monitors malfunction. For a Tier 4 unit, the owner or operator has the option to follow the CEMS certification and QA provisions of 40 CFR Part 60, 40 CFR Part 75, or an applicable State CEM program. This includes the criteria in those regulations pertaining to validation of the hourly CEMS data.

The provisions for hourly CEMS data validation in Part 60 are found in 40 CFR 60.13(h)(2)(i) through (h)(2)(vi). For Part 75, hourly data validation is addressed in 40 CFR 75.10(d)(1). The CEMS data validation criteria in these sections of Parts 60 and 75 are virtually identical. The basic requirement to validate an hour is that at least one data point must be obtained in each 15-minute quadrant of the hour in which the unit operates. There is one notable exception to this. For operating hours in which required maintenance or QA testing is performed, obtaining a valid data point in two of the four quadrants is sufficient.

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 are specified. In view of this, we are proposing to add a new paragraph, (c)(7), to 40 CFR 98.34(c), which would require hourly CEMS data validation to be consistent with the sections of Part 60 or Part 75 cited in the preceding paragraph. Alternatively, the hourly

data validation procedures in an applicable State CEM program could 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 municipal solid waste (MSW) and other units that combust combinations of fossil fuels and biomass. As specified in Part 98, flue gas samples are taken quarterly using ASTM Method D7459-08 and analyzed using ASTM Method D6866-08. We are proposing to amend 40 CFR 98.34(d) and (e), as discussed in the following paragraphs.

The proposed amendments to 40 CFR 98.34(d) would 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. Quarterly sampling with ASTM Method D7459-08 would still be required, for a minimum of 24 consecutive operating hours. However, we are proposing to add 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. This sampling approach is recommended by experts on the use of ASTM Methods D7459-08 and D6866-08 when the types of fuel and their composition are variable over time, as is the case with MSW combustion. For more information please refer to the Background Technical Support Document (EPA-HQ-OAR-2008-0508).

We are proposing to amend 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, would be allowed to determine biogenic CO₂ emissions using the ASTM methods on a quarterly basis. At least 24 consecutive hours of sampling is currently specified in 40 CFR 98.34(e). This is appropriate if the types of fuels and their relative proportions are consistent throughout the quarter. If the relative proportions are not consistent throughout the quarter, it may be more appropriate to consider collecting more frequent samples, however this is not required. Therefore, we are also amending 40 CFR 98.34(e) to recommend that a small (1 to 5 cc) flue gas sample be taken during each unit operating hour in the quarter.

Electronic Data Reporting and Recordkeeping. EPA will rely on

Agency verification of the electronic data provided in the annual GHG emission reports, in lieu of implementing third party verification. In order for Agency verification to be effective, sufficient information must be included in the electronic reports, at the facility, source category, and unit levels, to enable EPA to recalculate the reported GHG emissions and to quality-assure the data.

Section 98.36 of subpart C provides several lists of data elements that must be reported for stationary combustion units. These lists are specific to the CO₂ emissions calculation method employed (e.g., one of the four Tiers in 40 CFR 98.33(a) or a method in 40 CFR Part 75), and to the type(s) of electronic data report(s) that are submitted (e.g., individual unit reports, aggregated group reports, common pipe reports, etc).

EPA has begun developing software to check and verify the electronic data in the GHG emissions reports. As this effort has progressed, it has come to light that a number of important data elements are missing from the lists in 40 CFR 98.36, and that some of the data elements on the lists are either not needed or require an excessive amount of non-essential data to be reported.

To address these issues, we are proposing to amend 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 discussed in paragraphs (a) through (g), below. We are also proposing to add an additional alternative reporting option to 40 CFR 98.36(c) to reduce the reporting burden for certain facilities. This option is described in paragraph (h), below.

(a) We are proposing to add the reporting of methodology start and end dates in several places throughout 40 CFR 98.36(b), (c), and (d). These data elements are needed to accommodate changes in the methods used to calculate GHG emissions, when such changes occur during a reporting year or from one year to the next.

(b) We are proposing to amend 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.

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

(d) We are proposing to amend a number of data elements to reduce the reporting burden. For example, when small combustion units are aggregated into a group, 40 CFR 98.36(c)(1)(ii)

currently requires the ID number of each unit in the group to be reported. This requirement is unreasonable for facilities that have large numbers of very small combustion sources, many of which do not have unique ID numbers. We are, therefore, proposing to amend this data element to require that only the total number of units in the group be reported, instead of the ID number of each unit in the group. As a second example, for the common pipe option described in 40 CFR 98.36(c)(3), only the total number of units served by the common pipe would be reported, instead of reporting an ID number for each unit, and only the highest maximum rated heat input capacity of any unit served by the common pipe would be reported, rather than reporting the rated heat input capacity of each individual unit.

(e) We are proposing to amend 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) from 40 CFR 98.36(b)(9), (c)(1)(ix), (c)(2)(viii), and (c)(3)(viii). These data elements are duplicative of requirements in subpart A.

(f) We are proposing to amend 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 proposing to amend 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.

(g) We are proposing to amend 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 III.C of this preamble, the proposed amendments to 40 CFR 98.36(d) would state that reporting of biogenic CO₂ emissions is optional for units using the CO₂ mass emissions calculation methods in 40 CFR Part 75.

(h) For units that use the Tier 4 methodology to calculate CO₂ mass emissions, we are proposing to amend 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 proposed amendments to these sections will require the annual "non-biogenic" CO₂ mass emissions to be reported instead of reporting the annual CO₂ mass emissions from fossil fuel combustion.

These revisions are being proposed because the total annual CO₂ mass emissions measured by CEMS sometimes includes CO₂ from sorbent or process CO₂ emissions in addition to CO₂ from fossil fuel combustion. The effect of the proposed amendments would be to simplify reporting for Tier 4 units that have sorbent or process CO₂ emissions in the flue gas stream. These units would be required only to report the combined annual non-biogenic CO₂ mass emissions, rather than having to separately account for the fossil CO₂ emissions. Tier 4 units that do not have any sorbent or process CO₂ emissions in the flue gas would be unaffected by these proposed revisions, because their non-biogenic CO₂ emissions are entirely from fossil fuel.

(i) We are proposing to add a new alternative reporting option, under 40 CFR 98.36(c)(4). This new option would apply 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, you could 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.

Use of company records would be allowed to determine the percentage distribution of the shared fuel to the large and small units. Facilities using this reporting option would be 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 would suffice.

(j) Finally, we are proposing to simplify the record keeping requirements in 40 CFR 98.36(e)(2)(iii), in cases where the results of fuel

analyses for HHV are provided by the fuel supplier. Parallel language would be added in a new paragraph, (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 would be 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 dates may not be readily available).

We believe that these proposed amendments to the recordkeeping and reporting requirements of 40 CFR 98.36 are needed for data verification purposes. The proposed amendments are not likely to increase the reporting burden on industry. In some cases, as previously noted, the proposed amendments would actually reduce the amount of information that must be collected or reported and the associated burden.

Common Stack Reporting Option. Section 98.36(c)(2) of subpart C currently 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 Part 98. For example, if a Subpart G ammonia manufacturing unit shares a common stack with a Subpart C stationary combustion unit, the use of Tier 4 may be required (see 40 CFR 98.73(c)).

In view of this, we are proposing to amend 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 proposed amendments to 40 CFR 98.36(c)(2) would not only apply to ordinary common stack or duct situations where the gas streams from multiple units are combined together, but would also apply when process and combustion gas streams from a single unit (e.g., from a kiln, furnace, or smelter) are combined. To accommodate this variation on the traditional concept of a common stack, 40 CFR 98.36(c)(2)(ii) would be amended to require sources to report “1” as the

“Number of units sharing the common stack or duct” when process and combustion emissions from a single unit are combined and 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 proposing to amend 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 currently 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 proposing to amend 40 CFR 98.36(c)(3) as follows. First, the erroneous citation of “§ 98.34(a)” would be corrected to read “§ 98.34(b).” Second, we are proposing to amend 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 would apply only when Tier 3 is the required tier for calculating CO₂ mass emissions. The Agency believes that this clarification is needed, since the common pipe option can apply to Tier 1, 2, or 3, depending on the rated heat input capacities of the units served by the common pipe. Tiers 1 and 2 rely on company records to quantify fuel usage. Therefore, as noted in today’s proposed amendments to 40 CFR 98.3(i), 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).

As previously noted, 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 proposing to add a second one. First, 40 CFR 98.33(b)(2)(ii) 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. Second, proposed 40 CFR 98.33(b)(1)(v) would allow 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. Therefore, we are also proposing to amend 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 proposing to amend 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 proposing 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 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 would be 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. These default values are needed to calculate CO₂ mass emissions when the Tier 1 and Tier 2 methodologies in 40 CFR 98.33(a) are used. The fuels listed in Table C-1 are grouped into general categories (*e.g.*,

coal and coke, petroleum products, biomass fuels). Some distinctions are made within these categories, based on the state of matter (*e.g.*, biomass fuels—liquid, fossil fuel-derived fuels (solid), etc.).

Since publication of the final Part 98, EPA has received many questions about the content and structure of Table C-1. Owners and operators in various industries have raised a number of issues concerning the way that fuels are categorized, the description of certain fuels, the units of measure of some of the default HHV values, and the absence of some fuels that were listed in Table C-2 of the April 10, 2009 proposed rule. In particular:

(a) The categories "fossil fuel-derived fuels (solid)" and "fossil fuel-derived fuels (gaseous)" did not appear in the April 10, 2009 proposed rule and have been the source of some confusion. For instance, only two fuels, MSW and tires, are listed under "fossil fuel-derived fuels (solid)," and neither of these is derived entirely from fossil fuels. Both of these fuels have a biogenic component. There are also only two fuels, blast furnace gas and coke oven gas, listed in the "fossil fuel-derived fuels (gaseous)" category. Several other fuels that are derived from petroleum and qualify as fossil fuel-derived gaseous fuels (*e.g.*, still gas) are listed in a different category, "petroleum products."

(b) Questions have arisen about the revised description of "natural gas" in Table C-1. The word "pipeline," which was not in the April 10, 2009 proposed rule, was added in the final subpart C.

(c) The Agency has received questions about the meaning of the terms "wood residuals," "solid byproducts," and "agricultural byproducts," none of which appeared in the April 10, 2009 proposed rule.

(d) Questions have been asked why certain fuels that were listed in Table C-2 of the April 10, 2009 proposed rule do not appear in Table C-1. These include waste oil and plastics.

(e) Owners and operators have questioned the appropriateness of the units of measure for still gas listed under "petroleum products." The HHV for still gas, which is in the gaseous state at ambient temperatures, is given in mmBtu per gallon, as though it were in the liquid state.

(f) Some industry questions indicate that reporters believe that the footnote beneath Table C-1 appears to prohibit MWC units that produce steam from using the default CO₂ emission factor in the Table. This emission factor is needed to apply the Tier 2 CO₂ emissions calculation methodology

(specifically, Equation C-2c) to those units.

(g) EPA has received questions regarding the significance of indicating one hundred percent for ethanol and biodiesel, as well as questions regarding which emission factors to use for petroleum-derived ethanol.

In view of these considerations, we are proposing the following revisions to Table C-1:

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

- The word "pipeline" would be removed from the description of natural gas.

- The following fuels: "wood residuals," "agricultural byproducts," and "solid byproducts" would be retained, but definitions of these terms would be added to 40 CFR 98.6.

- "Waste oil" would be added to the list of petroleum products, and a definition would be added to 40 CFR 98.6.

- Still gas would be removed from the list of petroleum products.

- The footnote regarding MWC units would be revised to make it clear that MWC units that produce steam are only 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.

- The qualifier of one hundred percent for ethanol and biodiesel would be removed since these fuel types should be treated in the same way as other fuel types included in Table C-1. Removing this qualifier would clarify this without affecting any other provisions the rule.

- A default CO₂ emission factor and a default high heat value would be added to the Table for petroleum-derived ethanol. These would be the same as the default values for biomass-derived ethanol.

We are soliciting comment on these proposed amendments to Table C-1. Specifically, we request comment on: (1) The new and revised fuel categories; (2) the appropriateness of the HHVs and CO₂ emission factors for the fuels listed in these categories; and (3) whether additional fuels should be included in Table C-1, and if so, what the HHVs and CO₂ emission factors for those fuels should be.

Table C-2. In the October 30, 2009 publication of Part 98, two essentially identical iterations of Table C-2 of Subpart C were printed. The first iteration of Table C-2 was a printing error. We are proposing to remove the first iteration of the Table and to make minor corrections to the second one. The proposed amendments consist of correcting the exponents of the emission factors. The powers of ten in the right-hand column of the Table currently have an “underscore” character where there should be a minus sign, and one of the exponents is missing a zero.

Miscellaneous Proposed Revisions. In addition to the more substantive proposed amendments to Subpart C, we are proposing to correct a number of typographical errors, and to re-word the rule text in a few places for added clarity. We are also proposing to amend 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. Although these rule citations were inadvertently omitted from the October 30, 2009 publication of Part 98, we believe that Tier 4 sources understand that *all* required CEMS, including moisture monitoring systems, must be initially certified.

How Would These Amendments to Subpart C Apply to the 2011 GHG Emissions Reports? EPA plans to address the comments on the proposed amendments to Subpart C and to publish the final amendments before the end of 2010. Therefore, reporters would be expected to use provisions of Part 98, as amended, to collect the relevant data and to calculate GHG emissions for the reports that are submitted in 2011. We believe it is feasible for the sources to use the proposed changes to Subpart C for the 2010 reporting year, because the proposed revisions, to a great extent, simply clarify existing regulatory requirements. Further, the proposed amendments do not substantially affect the type of information that must be collected or how emissions are calculated.

The following are examples of how the proposed amendments to Subpart C would clarify existing regulatory requirements. The amendments would clarify:

- That reporting of biogenic CO₂ emissions is optional for units using the CO₂ mass emissions calculation methodologies in 40 CFR Part 75.
- How CH₄ and N₂O emissions are calculated for multi-fuel units that use the Tier 4 CO₂ mass emissions calculation methodology.
- How to determine whether Tier 4 applies to various common stack configurations.

- How to determine which Tier (*i.e.*, 1, 2, or 3) applies to common pipe configurations.

- How to calculate biogenic emissions for various types of units and fuels. Unnecessary restrictions on the use of certain calculation methods would be removed.

- How to apply the definition of a “fuel lot” at facilities that receive frequent deliveries of coal or fuel oil.

- How to calculate CO₂, CH₄, and N₂O emissions for blended fuels.

The proposed amendments to 40 CFR 98.36, the data reporting section of Subpart C, would achieve two main purposes: (1) To ensure that enough data are provided to enable the Agency to recalculate and verify the emissions data; and (2) to reduce burden, by removing the requirement to report certain non-essential data elements and by modifying other data elements.

For example, the proposed amendments would:

- Require methodology start and end dates to be reported. This will enable us to track changes in emissions calculation methodologies (e.g., switching from a lower Tier to a higher Tier).

- Generally require reporting of fuel-specific CH₄ and N₂O emissions. This requirement was inconsistently applied in Part 98.

- Eliminate the need to report individual unit ID numbers and unit heat input capacities for groups of aggregated units, common pipe configurations, and common stack configurations.

- Remove the unnecessary requirement to report unit-level combined CO₂, CH₄, and N₂O emissions from fossil fuel combustion.

- Remove the requirement for natural gas users to report their customer meter ID numbers.

- Emphasize that biogenic CO₂ emissions reporting is optional for Part 75 units.

EPA believes that amendments such as these can be implemented for the reports submitted to EPA in 2011 because the proposed changes are either consistent with or have no significant effect upon the calculation methodologies in Part 98. Since owners or operators are not required to report until March 2011, which is several months after we expect this proposal to be finalized, sources should have sufficient time to adjust to the revisions.

Several other proposed amendments to Subpart C address issues identified as a result of working with the affected sources during rule implementation. These proposed amendments would add flexibility to the rule. Owners or

operators would be free to implement these new rule provisions once they are finalized. The following are examples of how today’s proposed Subpart C amendments would make the rule more flexible. The proposed amendments would:

- Allow fuel flow meters that measure on a mass basis to be used for gaseous fuels as well as liquid fuels, provided that the flow rate measurements are corrected for density.

- Allow the span of CO₂ monitors to be set higher than 20 percent CO₂ if necessary, when process CO₂ and combustion CO₂ emissions exit to the atmosphere through a common stack.

- Allow the use of site-specific default moisture values for Tier 4 units that measure CO₂ concentration on a dry basis.

- Provide a new Tier 1 equation for calculating CO₂ mass emissions when fuel usage data obtained from gas billing records is expressed in units of therms.

- Allow smaller Tier 2 units (less than 100 mmBtu/hr) that receive monthly (or more frequent) HHV data to use an arithmetic average annual HHV in the emissions calculations instead of a fuel-weighted average HHV.

- Allow Tier 4 units to use an alternative (non-CEMS) method to account for the volumetric flow rate of a slip stream, when a portion of the flue gas is diverted and exhausts through a separate stack.

- Allow fuel oil sampling to be performed upon each addition of oil to the storage tank, as an alternative to sampling each fuel lot.

- Remove the lists of specific methods for determining HHV and carbon content and for fuel flow meter calibration, and specify instead that sources must either use appropriate methods from consensus standards organizations if such methods exist, or standard industry practice.

- Add a new reporting option for configurations in which a common supply of gaseous or liquid fuel is shared between large combustion units and a group of smaller units such as space heaters, hot water heaters, etc. If at least 95 percent of the shared fuel is used by the large units, 100 percent of the GHG emissions from combustion of that fuel may be attributed to the large units.

In some cases, facilities may have been following their current data collection practices during 2010, as well as using the methods required by Part 98. If a facility’s current practice provides the necessary data to implement the new options described immediately above, or if such data could be obtained and processed prior

to the March 31, 2011 reporting deadline, the new options could be used for the reports submitted to EPA in 2011.

Finally, the proposed amendments would make minor corrections to terms and definitions in certain Subpart C equations, and other technical corrections that would have no impact on facility's data collection efforts in 2010.

In summary, EPA believes that, in general, the proposed amendments to Subpart C would not require monitoring or information collection above what is already required by Part 98. Therefore, we expect that sources will be able to use the same information that they have been collecting under Part 98 to calculate and report GHG emissions for 2010.

EPA seeks comment on its conclusion that the amendments to Subpart C can be implemented and incorporated into the initial GHG emissions reports by the due date of March 31, 2011. Specifically, we seek comment on 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 request that commenters provide specific reasons why they believe that the proposed implementation schedule would or would not be feasible.

H. Subpart D (Electricity Generation)

We are proposing to amend 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: (a) ARP units; and (b) non-ARP electricity generating units (EGUs) that are required to report CO₂ mass emissions data to EPA year-round. At present, category "(b)" includes only non-ARP units that are subject to the Regional Greenhouse Gas Initiative (RGGI) in the northeastern United States.

Many non-ARP EGUs that are not in the RGGI are subject to the Clean Air Interstate Rule (CAIR). Some of these CAIR units report CO₂ concentration data to EPA year-round, for the purposes of calculating NO_x emission rates in lb/mmBtu and/or heat input rates in mmBtu/hr. However, they do not report CO₂ mass emissions data to the Agency. Therefore, they are subject to Subpart C of Part 98, not Subpart D.

Data Reporting Requirements. Section 98.46 of subpart D currently specifies 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 are 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 proposing to amend 40 CFR 98.46 to correct this error.

Recordkeeping. We are proposing to amend 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 believe 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).

I. Subpart F (Aluminum Production)

Throughout Subpart F we are proposing corrections as needed for typographical errors and alphanumeric sequencing. We are proposing to amend 40 CFR 98.63, Calculating GHG Emissions, to clarify that each perfluorocarbon (PFC) compound (CF₄, C₂F₆) 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 proposing to amend 40 CFR 98.64, Monitoring and QA/QC, 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 which are not measured annually, but are instead measured on a more or less frequent basis. We are proposing a modification to 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 proposing to amend Table F-1 to spell out the acronyms for the technologies covered by that table; *i.e.*, CWPB, side worked prebake (SWPB), vertical stud Soderberg (VSS), and horizontal stud Soderberg (HSS).

J. Subpart G (Ammonia Manufacturing)

We are proposing to amend subpart G to remove reporting of the waste recycle stream or purge, and to make subpart G conform to the proposed amendments to the calibration requirements in Subpart A. With respect to the waste recycle stream, we are proposing to eliminate 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 proposing to amend 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.

With respect to calibration requirements, we are proposing to clarify the calibration requirements for gas and oil flow meters used in the ammonia manufacturing process. Section 98.74(d) of subpart G currently states that all oil and gas flow meters except for gas billing meters must be calibrated according to the requirements for the Tier 3 methodology in 40 CFR 98.34(b). The Agency believes that the words "all oil and gas flow meters" in this subpart G provision are too inclusive and subject to misinterpretation. Therefore, we are proposing to amend 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 would 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 proposing to note through parentheticals in a number of places that the CO₂ emissions estimates 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 proposed change does not impact the total CO₂ emissions that are quantified and reported to EPA under the calculation equations in 40 CFR 98.73. The clarification is proposed so

that it is transparent for stakeholders who ultimately use these data that some CO₂ process emissions reported by the ammonia manufacturing process unit under this subpart may not be released from ammonia manufacturing, but at the point of urea application. To further enhance this transparency, EPA is also proposing to require reporting under 40 CFR 98.76 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 proposing to amend Subpart G to correct several typographical errors and an incorrect cross-reference to another subpart in Part 98. We are proposing to correct 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 proposing to correct 40 CFR 98.76(a) by changing the cross-reference from “§ 98.37(e)(2)(vi)” to “§ 98.37.”

We are proposing to amend 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 proposing to amend 40 CFR 98.76(b)(6) to change “petroleum coke” to “feedstock” because petroleum coke is the incorrect term, and to amend 40 CFR 98.76(b)(15) to specify that the carbon content analysis method being reported is for each month.

We are proposing to remove 40 CFR 98.76(b)(17) for the reporting of urea produced, if known. EPA finalized reporting of this information to help improve methodologies for calculating emissions from ammonia manufacturing, urea production and urea consumption. Reporters stated that these data are already reported periodically to EPA under the Toxic Substances Control Act (TSCA) Inventory Update Rule (IUR). Although the TSCA IUR does not provide the full range of information that may ultimately be useful for informing future policy, EPA believes that the TSCA IUR provides adequate information at this time and, therefore, we are proposing to delete that requirement.

Finally, 40 CFR part 98, subpart G (Ammonia Manufacturing) and subpart V (Nitric Acid Production) require that facilities report total pounds of synthetic fertilizer and total nitrogen contained in that fertilizer. After considering additional information provided by stakeholders, as well as other available information, we are proposing to remove the requirement from both subparts. EPA’s rationale for removing the requirement is as follows

(i) The data that would be reported under these subparts do not provide directly applicable information with which to determine N₂O emissions from application of fertilizer because the data are incomplete. Domestic producers of synthetic nitrogen-based fertilizer make up less than one-half of the total amount of synthetic nitrogen-based fertilizer used in the United States. The remaining share is made up by synthetic nitrogen-based fertilizer imports, as well as fertilizer produced domestically outside of the Nitric Acid and Ammonia production industries using imported ammonia and nitric acid.

(ii) EPA has information on the total supply and use of synthetic nitrogen-based fertilizer from other data sources that addresses near-term analytical needs, particularly for calculating national emissions of N₂O. We obtain current sales data from Association of American Plant Food Control Officials (AAPFCO). The sales data is equivalent to fertilizer application since the sales are from the last licensed dealer.

EPA remains very interested in obtaining better data on N₂O emissions. Nitrous oxide emissions from agricultural soils are an important source of greenhouse gas emissions in the United States (approximately 3 percent in 2008), and the application to soils of synthetic nitrogen-based fertilizer represents 26 percent of total N₂O emissions from this source.

EPA will continue to assess the need for a fertilizer reporting requirement from domestic producers in the future in light of new information or identification of policy or program needs. Further, EPA recognizes that States play an important role in collecting the data EPA currently uses, and the AAPFCO has indicated in a published article that recent stresses on state budgets potentially threaten the continued availability of these data.³ If data collection is compromised further due to reduced state funding or other circumstances, EPA will need to initiate a fertilizer reporting requirement.

EPA will also assess the need for information on the total supply of synthetic nitrogen-based fertilizer, including imports, production of fertilizer using imported feedstock, domestically-produced fertilizer that is not in the agriculture sector, and fertilizer exports.

Additionally, EPA will also assess the need for other types of information (*i.e.*, not related to fertilizer supply) relevant to determining emissions and assessing

mitigation opportunities for N₂O emissions from agricultural soils, consistent with the Clean Air Act. Examples of other types of information that is relevant to N₂O oxide emissions from agricultural soils can be found in the “Technical Support Document for Biologic Process Sources Excluded from this Rule,” and include elements such as fertilizer application rates, timing of application, and the use of slow-release fertilizers and nitrification/urease inhibitors (Docket ID No. EPA-HQ-OAR-2008-0508).

If EPA were to decide in the future to add a requirement to report fertilizer production under the Mandatory GHG Reporting Rule, or any other new requirement related to N₂O emissions from agricultural soils, it would initiate a new rulemaking process.

K. Subpart P (Hydrogen Production)

We are proposing several conforming amendments to be consistent with the proposed amendments to the calibration requirements of 40 CFR 98.3(i). Section 98.164(b)(1) of subpart P currently specifies that all oil and gas flow meters (except for gas billing meters), solids weighing equipment, and oil tank drop measurements must be calibrated according to 40 CFR 98.3(i). We are proposing to amend 40 CFR 98.164(b)(1) to make it consistent with today’s proposed amendments to 40 CFR 98.3(i). First, we would limit 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 device that are used to provide data for the GHG emissions calculations would 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. Second, we would remove 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) would apply only to gas and liquid flow meters. For oil tank drop measurements, the QA requirements of 40 CFR 98.34(b)(2) would apply.

L. Subpart V (Nitric Acid Production)

We are proposing to amend 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 proposed amendment is provided in section II.K of this preamble.

³D. Terry, 2006. “Fertilizer Tonnage Reporting in the U.S.—Basis and Current Need.” *Better Crops*. 90(4). pp 14–17.

M. Subpart X (Petrochemical Production)

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 proposed amendments include the following:

- Distillation and recycling of waste solvent.
- Process vent emissions monitored by CEMS.
- Process off-gas combustion in flares.
- CH₄ and N₂O 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.

Distillation and Recycling of Waste Solvent. We are proposing to add a new paragraph 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. Some processes that distill or recycle waste solvents may produce products that contain methanol or another petrochemical. Under the current subpart X, such processes might be considered part of the petrochemical source category because 40 CFR 98.240(a) specifies that all processes that produce a petrochemical are part of the source category unless specifically excluded. Although not specifically excluded in subpart X, we did not intend to include waste solvent purification processes in the petrochemical source category for the following reasons. First, in processes subject to subpart X, the petrochemical is formed from other chemicals, whereas in waste solvent purification processes the petrochemical is not formed because it is present in the feedstock. Second, processes that are in the source category generate significant amounts of process-based GHG emissions as byproducts of reaction and/or from the combustion of process off-gas for energy recovery. In contrast, the only process-based GHG emissions, if any, from waste solvent purification processes are from combustion of organic compounds in process vent emissions that are routed to a combustion-based air pollution control device.

Process vent emissions monitored by CEMS. We are proposing to add a

sentence 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). Section 98.242(a)(1) in the current subpart X specified that GHG emissions from stationary combustion sources and flares that burn any amount of petrochemical off-gas are to be reported under subpart X. However, we neglected to specify reporting requirements under the CEMS option for process emissions that are not associated with combustion units. The proposed amendment would correct this oversight.

Process off-gas combustion in flares. We are proposing to amend 40 CFR 98.242(b) by removing the reference to flares. Section 98.242(b) in subpart X specifies that CO₂, CH₄, and N₂O combustion emissions from stationary combustion units and flares must be reported. However, the intent of 40 CFR 98.242(b) is to identify only the GHGs from the combustion of supplemental fuels that are to be reported under subpart C. Emissions from the combustion of petrochemical process off-gas in a flare are process-based emissions that are to be reported under subpart X as specified in 40 CFR 98.242(a). Therefore, the reference to flares in 40 CFR 98.242(b) is incorrect and should be removed.

CH₄ and N₂O Emissions From Combustion Of Process Off-Gas. We are proposing to amend 40 CFR 98.243(b) to clarify procedures for calculating CH₄ and N₂O emissions from combustion units that burn petrochemical process off-gas and are monitored with a CO₂ CEMS. Section 98.243(b) in subpart X specifies that CH₄ and N₂O emissions from the non-flare combustion of petrochemical process off-gas are to be calculated using the Tier 3 procedures in subpart C, with the default emission factors for "Petroleum" in Table C-2 of subpart C. This procedure requires the use of equation C-8 to calculate the emissions. One of the inputs for this equation is the default HHV of the fuel, and default values for various fuels are listed in Table C-1 of subpart C. As discussed in section II.H of this preamble, we have added a default HHV for fuel gas in Table C-1, and we have revised the definition of HHV for equation C-8 to allow the use of a site-specific calculated HHV as an alternative to using a default value from Table C-1. Using either a default HHV or a site-specific calculated value is also acceptable when calculating CH₄ and N₂O emissions from the combustion of fuel gas that contains petrochemical

process off-gas. Therefore, to clarify this point, we are proposing to add language to 40 CFR 98.243(b) specifying that either the default HHV for fuel gas in Table C-1 or a site-specific calculated HHV is to be used in equation C-8 when calculating CH₄ and N₂O emissions.

For the ethylene-specific option, 40 CFR 98.243(d) in subpart X specifies the same procedures for calculating CH₄ and N₂O emissions from non-flare combustion of process off-gas as in 40 CFR 98.243(b). Therefore, we are proposing the same change to 40 CFR 98.243(d) as noted above for 40 CFR 98.243(b) to clarify that either the default HHV for fuel gas or a site-specific calculated HHV should be used for Tier 3 calculations.

Molar volume conversion (MVC) factors. Owners and operators have requested that allowance be made for alternative standard conditions within the molar volume conversion factor (MVC) used in Equation X-1 in 40 CFR 98.243(c). Equation X-1 of subpart X specified using an MVC of 849.5 scf/kgmole, which converts the volumetric flow from standard cubic feet to kgmoles assuming the standard volume was determined at 68 °F. Exhaust stack volumes are generally corrected using 68 °F as the standard temperature, and some petrochemical producers may also use 68 °F when expressing process volumes at standard conditions. However, we recognize that the oil and gas industry and other hydrocarbon processing facilities commonly express gaseous volumes using 60 °F as the standard temperature. Thus, many existing flow monitors for gaseous feedstocks and products at petrochemical facilities may be programmed to output volumes at standard conditions of 60 °F. It is impractical and unnecessary to either reprogram these monitors to provide volumes corrected to standard conditions at 68 °F or to require reporters to convert the output volumes from one set of standard conditions to another before using Equation X-1 because an alternative MVC can be provided to yield the identical mass emissions from the calculation.

Consequently, we are proposing to amend Equation X-1 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 would be amended 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. Owners and operators have suggested that EPA should allow the use of alternative calculation methods for small emission sources. Specifically, they have asserted that units subject to only subpart C are allowed to use Tier 1 or Tier 2 for units less than or equal to 250 mmBtu/hr heat input. However, if those same units are at a petrochemical production facility and combusting ethylene process off-gas, they are required to use Tier 3 or Tier 4.

We still believe that it is important to use Tier 3 or Tier 4 for most units that burn ethylene process off-gas because combustion of process off-gas is the primary source of GHG process emissions for ethylene processes, the carbon content may vary among facilities depending on the type of feedstock to the ethylene process units, and the ratio of ethylene process off-gas to other fuels may vary in each fuel gas system.

However, we recognize that some ethylene process off gas that is burned in process heaters or boilers may not enter the fuel gas system and that the lines conveying these off-gas streams may not have flow monitors. For example, 40 CFR part 63, subpart YY, requires control of process vent emissions from ethylene production process units; these streams may be controlled by venting to a process heater or boiler, but subpart YY does not require monitoring of the vent stream flow rate. It was not our intent to require the installation of flow meters on these ancillary gas streams that do not significantly contribute to the overall heat input of the stationary combustion unit. In addition, we recognize that facilities may only meter the primary fuel flow at relatively large combustion units that are subject to emission limitations that are related to the heat input rate. About one-third of the ethylene production capacity is at petroleum refineries, and much of the rest is at large integrated chemical manufacturing facilities. Based on an analysis of process heaters at petroleum refineries (*see* section II.O of this preamble), it appears that process heaters less than 30 mmBtu/hr are often not subject to emission limitations and, therefore, may not have metered flow. Furthermore, such combustion units appear to represent only a small percentage of the total fuel use at refineries. Given the large size of most other chemical manufacturing facilities that make ethylene, it is likely that such combustion units represent only a small percentage of total fuel use at these facilities as well. Thus, easing the Tier

3 monitoring requirements for these small combustion units would reduce the compliance burden without significantly impacting the accuracy of the nationwide GHG emission inventories for ethylene production.

Notwithstanding the above discussion, if a flow meter is installed in the fuel gas line, including any common pipe, then we consider that the Tier 3 monitoring requirements are reasonable and justified. In such cases there will not be a significant burden to use the Tier 3 method, and the reported GHG emissions will be more accurate.

Therefore, we are proposing to amend 40 CFR 98.243(d) 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, we are proposing that Tier 1 or Tier 2 methods may be used for ethylene process off-gas streams that meet either of the following conditions:

(1) 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 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 an upstream common pipe; or

(2) 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.

This amendment would also specify 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. We are also proposing a number of editorial changes to 40 CFR 98.243(d) to clearly integrate the proposed option with the existing requirements. Finally, we are proposing to amend 40 CFR 98.246(c)(2) and 98.247(c) to add reporting and recordkeeping requirements that are related to the proposed amendments in 40 CFR 98.243(d)(2).

Monitoring Methods for Determining Carbon Content and Composition. Owners and operators have suggested that EPA should not limit the use of gas chromatograph methods for determining the carbon content, composition, and the average molecular weight of feedstocks and products to those methods listed in 40 CFR 98.244(b)(4). We are proposing to add the method, “ASTM D2593–93 (Reapproved 2009) Standard Test Method for Butadiene

Purity and Hydrocarbon Impurities by Gas Chromatography,” to 40 CFR 98.244(b)(4). Butadiene is a by-product of the ethylene production process, and after reviewing the method, we have determined that it is an acceptable method for determining the carbon content of that stream. We will consider including additional methods in the final amendments after reviewing comments on this issue. In order to evaluate this issue, we seek comments providing copies of calibration procedures that gas chromatograph manufacturers supply with their equipment, calibration procedures in any published or unpublished industry consensus (or site-specific) methods not currently listed in 40 CFR 98.244(b)(4), and an assessment of how such procedures compare to the currently specified methods and why they are applicable for instruments used to measure petrochemical feedstocks and products.

We are proposing to further amend 40 CFR 98.244(b)(4) by adding a new paragraph that would allow the use of industry consensus standard methods to determine the carbon content or composition of carbon black feedstock oils and carbon black products. Carbon black manufacturers have reported that none of the listed methods are specific to carbon black materials, and they have stated that such methods will provide less accurate results than modified versions of some of the methods. For example, the industry has reported that when they need to determine the carbon content of their feedstocks or products they often use modified versions of ASTM D5291–02. One difference is that the modified methods use carbon or carbon/sulfur analyzers instead of the carbon, hydrogen, and nitrogen analyzer that is specified in ASTM D5291–02. These modified methods have been submitted to ASTM for review. If ASTM publishes methods before the proposed amendments are finalized, we will consider including them in the final amendments. The industry has also reported that they often use other published methods to determine the sulfur, ash, and water content of the material and then calculate the carbon content as the difference between the mass of these compounds and the total mass of the sample. This approach would also be allowed under the proposed change to 40 CFR 98.244(b)(4). We seek comment on the need for the proposed option. In particular, we are interested in data that compare specified methods such as ASTM D5291–02 with industry consensus methods. We are also interested in

obtaining copies of industry consensus standard methods.

We are also proposing to amend 40 CFR 98.244(b)(4) to provide facilities the option of, under certain circumstances, the use of alternative analytical methods in addition to the methods listed in 40 CFR 98.244(b)(4)(i) through (b)(4)(xi) for determining the carbon content or composition of feedstocks or products. We recognize that the applicability of the methods listed in 40 CFR 98.244(b)(4)(i) through (b)(4)(xi) may be restricted for certain process streams due to the analytical limitations of those methods and/or the instrumentation. As a result, we are proposing to allow a facility to use an alternative analytical method in cases where the methods listed in 40 CFR 98.244(b)(4)(i) through (b)(4)(xi) 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.

We are proposing to amend the reporting requirements in 40 CFR 98.246(a)(11) so that if an alternative method is used, facilities would 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.

We solicit comment on whether the flexibility provided by this option is needed. If commenters believe that to be the case, please provide information on the specific need for flexibility, why the existing listed analytical methods are not sufficient, and whether the proposed flexibility meets the needs identified.

We are proposing to make the amendments to 40 CFR 98.244(b)(4) as described above retroactive to January 1, 2010. We have received feedback that some reporters are using a method currently allowed in Part 98 while concurrently also using a method that would be allowed by today's action. Should these amendments be finalized, making these amendments effective January 1, 2010 would allow reporters to use the results from the methods included in today's amendments for the entire year of 2010.

QA/QC Requirements. As mentioned in Section II.B of this preamble, owners and operators have raised several issues regarding the calibration requirements in Part 98, and we are proposing a number of changes to 40 CFR 98.3(i) of subpart A to address those issues. To maintain consistency with the proposed amendments to 40 CFR 98.3(i), we are also proposing amendments to the QA/QC provisions for weighing devices, flow meters, and tank level

measurement devices in paragraphs (b)(1), (b)(2), and (b)(3) of 40 CFR 98.244. Other proposed amendments to these paragraphs are editorial in nature and intended to clarify the requirements. Specific changes are as follows:

In 40 CFR 98.244(b), each of the three subparagraphs incorrectly required compliance with calibration requirements in 40 CFR 98.3(i), or with any of the following: procedures specified by equipment manufacturers, industry consensus standard procedures, or procedures in listed methods. We are proposing to amend these subparagraphs such that the procedures in 40 CFR 98.3(i) would apply in addition to the other required procedures.

We are proposing to amend 40 CFR 98.244(b)(1) to allow recalibration at the interval specified by the industry consensus standard practice used in addition to either biennially or at the minimum frequency specified by the manufacturer. Note that the requirements of 40 CFR 98.3(i) for other measurement devices would apply as well.

Section 98.244(b)(2) in subpart X specifies that flow meters are to be operated and maintained using the procedures in 40 CFR 98.3(i) and either any one of several listed methods, a method published by a consensus-based standards organization, or procedures specified by the flow meter manufacturer. Although 40 CFR 98.244(b)(2) references 40 CFR 98.3(i), it does not explicitly specify calibration requirements, and this reference incorrectly implies that 40 CFR 98.3(i) specifies procedures other than calibration requirements. In addition, the option to follow procedures in any of the listed methods is redundant because it overlaps with the option to use a method published by a consensus standards-based organization. To clarify these requirements we are proposing several amendments to 40 CFR 98.244(b)(2). One would specify that flow meters are to be operated and maintained according to manufacturer's recommended procedures. A second would specify that flow meters are to be calibrated following either an industry consensus standard practice or procedures specified by the flow meter manufacturer, and must meet the accuracy specification in 40 CFR 98.3(i). Finally, the list of specified methods would be deleted.

Section 98.244(b)(2) in subpart X specifies that flow meters are to be recalibrated either biennially or at the minimum frequency specified by the flow meter manufacturer. Since 40 CFR

98.244(b)(2) specifies that flow meters may be calibrated following procedures in industry consensus standard practices, we are proposing to also allow recalibration at the frequency specified in such methods. This would also make the recalibration requirements in 40 CFR 98.244(b)(2) consistent with the proposed amendment in 40 CFR 98.3(i)(1)(iii)(B).

Section 98.244(b)(3) in subpart X specifies that tank level measurement devices are to be calibrated prior to the effective date of the rule. We are proposing to delete this statement because 40 CFR 98.3(i) specifies the date by which initial calibration must be completed. Note that the requirements for other measurement devices in 40 CFR 98.3(i) apply as well.

Reporting Requirements Under The CEMS Compliance Option. We are proposing 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 proposing to move 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 proposing to add 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 proposed action) for CH₄ and N₂O do not apply under subpart X. This reporting requirement in subpart C is not relevant in subpart X because 40 CFR 98.246(b)(5) specifies the reporting requirements for CH₄ and N₂O under subpart X.

Third, in the renumbered 40 CFR 98.246(b)(3), we are proposing to delete 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 you still must 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 proposing to amend 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 proposing changes to 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 would be unchanged. We are proposing changes to 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 would also include emissions from combustion of supplemental fuel (if any).

Finally, we are proposing 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 proposed action). Most of the proposed amendments to 40 CFR 98.246(b)(5) restate requirements from 40 CFR 98.36(b)(9)(iii); for example, the proposed 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, 40 CFR 98.246(b)(5) also would require you to 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) would require reporting of the HHV that you use in Equation C–8. This change also would delete the erroneous reference to Equation C–10 that was included in 40 CFR 98.246(b)(5).

Reporting Requirements for the Ethylene-Specific Option. We are proposing several changes to clarify the reporting requirements in 40 CFR 98.246(c) for the ethylene-specific option. First, we are proposing to add 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 proposing 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, because ethylene is the only petrochemical product for process units that can comply with the ethylene-specific option, we are

proposing to replace 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. In 40 CFR 98.246(a)(7) we are proposing to delete the requirement for reporting of the dates and summarized results of calibrations of each measurement device under the mass balance option. We have determined that maintaining records of this information will be sufficient. Thus, we are also proposing to add 40 CFR 98.247(b)(4) to require retention of these records.

N. Subpart Y (Petroleum Refineries)

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 proposed 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 thermal oxidizers.
- 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.
- Reactor vessels using methane as a blanket or purge gas.
- Monitoring and QA/QC requirements.
- Reporting requirements.

GHG Emissions From Flares. We are proposing several corrections to 40 CFR 98.252(a) (GHGs to report) to clarify the required emissions methods for flares. From the first sentence in 40 CFR 98.252(a), it is clear that CO₂, CH₄, and N₂O combustion emissions are to be calculated for stationary combustion units and for each flare. However, the second sentence suggests that petroleum refinery owners or operators are to “[c]alculate and report *these* emissions under subpart C * * *” (emphasis added). After the first sentence, the

remainder of 40 CFR 98.252(a) specifically addresses how petroleum refinery owners or operators are to calculate and report stationary combustion unit emissions. Flare emissions are to be calculated using the methods provided in subpart Y, not the methods provided in subpart C.

Consequently, 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 reports must “Calculate and report the emissions from flares under this subpart.”

GHG Emissions to Report From Combustion of Fuel Gas. We are proposing to amend 40 CFR 98.252(a) to clarify that reporting of CH₄ and N₂O emissions is required for the stationary combustion units fired with fuel gas. It was always our intent that the emissions of these pollutants be reported for stationary combustion sources that used fuel gas. However, as no default factors for fuel gas were previously included in Table C–1 of subpart C, it could be interpreted that these emissions were not required to be reported, even though the first sentence clearly indicates that emissions of all three pollutants were to be reported for stationary combustion units and flares. While the proposed amendment to Table C–1 to include default factors for “fuel gas” is expected to correct this misinterpretation, we are also proposing to add the following sentence to 40 CFR 98.252(a) to clarify these reporting requirements: “For CH₄ and N₂O emissions from combustion of fuel gas, use the applicable procedures in 40 CFR 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 subpart C of this part and for Tier 3, 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.”

GHG Emissions To Report From Non-Merchant Hydrogen Production Process Units. We are also proposing to amend 40 CFR 98.252(i) to clarify that reporting of only CO₂ emissions from non-merchant hydrogen production process units is required. The inclusion of “and CH₄” emissions was an inadvertent error. We are also proposing to amend 40 CFR 98.252(i) to clarify that catalytic reforming units (although they produce hydrogen as an important by-product) are not considered hydrogen production

process units that are required to report under 40 CFR 98.252(i).

Calculating GHG Emissions From Fuel Gas Combustion. Owners and operators have suggested that EPA should allow the use of alternative calculation methods for small emission sources from the combustion of fuel gas. Specifically, they have asserted that units subject to only subpart C may use Tier 1 or Tier 2 if the units are less than or equal to 250 mmbtu/hr heat input. However, if those same units are at a petroleum refinery and combusting fuel gas, they are required to use Tier 3 or Tier 4. We still believe that it is important to use Tier 3 or Tier 4 for most units at a petroleum refinery because of the variability in carbon content in fuel gas (both between different refineries and at different times within the same refinery). However, we recognize that some flows of fuel gas to process heaters or boilers may not necessarily enter the refinery's fuel gas system and that these fuel gas lines may not have flow monitors. For example, 40 CFR part 63 subpart UUU requires the control of purging operations associated with the catalytic reforming unit. Among the control options for these emissions are provisions to vent these gases to a boiler or process heater. If the stationary combustion source has a design capacity of 44 MW or greater or if the gases are introduced into the flame zone of the unit, then direct monitoring of these gas streams is not required under subpart UUU. Similar provisions that may pertain to petroleum refineries are in other rules (e.g., 40 CFR part 60, subparts III and NNN; 40 CFR part 63, subparts G and CC). It is not our intent to require direct flow monitoring of these ancillary gas streams, particularly if they do not significantly contribute to the overall heat input of the stationary combustion unit.

In addition, while we anticipate that most refineries can use a common-pipe monitoring approach for stationary combustion sources supplied by the refinery's fuel gas system(s), we recognize that some refineries may meter fuel usage at the stationary combustion sources and, in some cases, only meter fuel usage at the larger units. Based on a review of consent decrees and permits pertaining to process heaters, it appears that process heaters less than 30 mmBtu/hr are often not subject to emission limitations, and therefore may not have metered flow. We performed an analysis of fuel use requirements by process unit. From this analysis, we project that more than 95 percent of nationwide fuel gas consumption at petroleum refineries

would occur in process heaters with a rated heat capacity of 30 mmBtu/hr or greater. For additional detail on the consent decree review as well as the analysis of fuel use requirements, please see the Background Technical Support Document (EPA-HQ-OAR-2008-0508). While these small process heaters represent only a small percentage of the fuel use on a national level, most process heaters at petroleum refineries with capacities under 25,000 barrels per day (which represents about 20 percent of the refineries, but only 2 percent of the refining capacity) are expected to have rated heat capacity of less than 30 mmBtu/hr. Thus, easing the Tier 3 monitoring requirements for these smaller process heaters would significantly ease the burden for small refineries without significantly impacting the accuracy of the nationwide GHG inventories for petroleum refineries.

If 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. There will not be a significant burden to use the Tier 3 method and the reported GHG emissions will be more accurate given the fluctuations expected in fuel gas compositions.

Therefore, we are proposing to amend 40 CFR 98.252(a) so that petroleum refineries subject to subpart Y could use the Tier 1 or 2 methodologies for combustion of fuel gas when either of the following conditions exists:

(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 scfm at 60°F and 14.7 psia and either of the following conditions exist:

- 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.

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

- 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.

These amendments, combined with the revisions to Table C-1 of subpart C, reflect our original intent to require Tier 3 or 4 monitoring and calculation methods for large fuel gas streams such as those anticipated in the refinery's fuel gas system(s), but to allow Tier 1 or 2 monitoring methods for smaller fuel gas streams that are segregated from the fuel gas system or for small combustion sources at refineries where flow monitors are installed at the majority of individual combustion sources, but not at the smaller combustion sources or the common pipe (i.e., fuel gas system).

Calculating Combustion GHG Emissions From Flares And Thermal Oxidizers. It has been brought to our attention that it is inappropriate to apply the 98 percent combustion efficiency to the carbon as CO₂ that already exists in the gas stream in Equations Y-1 and Y-16 in 40 CFR 98.253. While the correction is expected to be minor in most cases, we agree that all of the CO₂ that already exists in the gas stream will be emitted as CO₂ from these sources. However, we are concerned that, depending on the method used to determine the carbon content, some facilities may not have collected the specific CO₂ data needed to implement the revised equations. Therefore, we are proposing to amend 40 CFR 98.253 by retaining the existing Equations Y-1 and Y-16, re-numbering them as Equations Y-1a and Y-16a, and to add the more detailed equations that specifically consider the CO₂ that already exists in the gas stream prior to the flare or thermal combustion device as Equations Y-1b and Y-16b. Facilities that were required to or elected to use Equation Y-1 to report flare emissions would be able to choose to report these emissions using either Equation Y-1a or Y-1b, as proposed in today's amendments. Similarly, we are proposing to allow facilities required to report CO₂ emissions from asphalt blowing operations controlled by a thermal oxidizer or flare to use either Equation Y-16a or Y-16b. We are proposing corresponding amendments in 40 CFR 98.256 to require reporting of which equation was used and, if the new equations are used, reporting of the additional equation parameters.

We request comment on the need to retain the previously promulgated equations. As gas composition data are expected to be determined using gas chromatographic methods, the required CO₂ data may already be collected. Thus, we are particularly interested to determine if there are facilities that cannot implement the new equations based on the measurement data already

collected for these sources during the 2010 reporting year.

Molar volume conversion factors.

Owners and operators have suggested that allowance be made for alternative “standard conditions” within the MVC factor used in several of the equations in 40 CFR 98.253. We recognize that natural gas and fuel gas volumes are commonly determined using 60°F as the standard temperature whereas exhaust stack volumes are commonly determined using 68°F as the standard temperature. Both of these volume measurements are specified in subpart Y. It is impractical and unnecessary for existing fuel gas monitors, most of which have been installed to correct volumes to standard conditions at 60°F, to be reprogrammed to output these volumes corrected to standard conditions at 68°F when an alternative MVC can be provided to yield the identical mass emissions from the calculation. Consequently, we are proposing to amend equations Y-1, Y-3, Y-6, Y-12, Y-18, Y-19, Y-20, and Y-23 in subpart Y to provide two alternative values of MVC depending on the standard conditions output by the flow monitors. Additionally, the reporting requirements related to each of these equations would be amended to include reporting of the value of MVC used to support the calculations and to afford verification of the reported emissions.

Combined Stacks Monitored By CEMS. We received several questions regarding whether or not discharges through a combined stack are allowable when CEMS are used, particularly for the catalytic cracking unit. We never intended to limit the use of combined stacks and CEMS at the refinery. In fact, we specifically attempted to address this issue in subpart Y with respect to the combined catalytic cracking unit and CO boiler emissions in 40 CFR 98.253(c)(1)(ii). However, we have determined that the current language in 40 CFR 98.253(c)(1)(ii) may inadvertently be interpreted to exclude other CO₂ emission sources that may be mixed with the catalytic cracking unit process (e.g., coke burn-off) emissions.

Consequently, we are proposing to amend 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. The proposed amendments would clarify that when a CEMS is used to measure the CO₂ emissions from the catalytic cracking unit and these emissions are combined with “other CO₂ emissions,” the owner or operator must calculate the “other CO₂ emissions”

using the applicable methods for the applicable subpart (e.g., subpart C of this part in the case of a CO boiler), and determine the process emissions from the catalytic cracking unit (or fluid coking unit) as the difference in the CO₂ CEMS measurements and the calculated emissions associated with the “other CO₂ emissions.”

Nitrogen Concentration Monitoring To Determine Exhaust Gas Flow Rate. We also received questions regarding the use of nitrogen (N₂) concentration monitoring for Equation Y-7 in 40 CFR 98.253(c)(2)(ii). Equation Y-7 uses an inert balance to calculate the exhaust gas flow rate, and a similar calculation can be performed using a nitrogen balance. We agree that the nitrogen monitoring approach would provide an equivalent measure of the exhaust gas flow rate as Equation Y-7. We promulgated Equation Y-7 because we anticipated several facilities used this monitoring approach as this equation is provided in the 40 CFR part 63 subpart UUU (see Equation 2 of 40 CFR 63.1573). However, we note that 40 CFR 63.1573 also allows facilities to request alternative monitoring methods. There are no similar provisions in subpart A or subpart Y of part 98, so this monitoring alternative could not be used without amending the rule. As we find the N₂ concentration monitoring approach to be equivalent to Equation Y-7, we are proposing to amend 40 CFR 98.253(c)(2)(ii) to renumber Equation Y-7 as Equation Y-7a and adding an Equation Y-7b to provide this N₂ concentration monitoring approach. We are also proposing to add reporting requirements in 40 CFR 98.256(f) to report the input parameters for Equation Y-7b if it is used.

Calculating CO₂ Emissions from Catalytic Reforming Units. We are proposing to revise the definition of the coke burn-off quantity, CB_Q, the term “n” in Equation Y-11 in 40 CFR 98.253(e)(3) to clarify the application of Equation Y-11 to continuously regenerated catalytic reforming units. Continuously regenerated catalytic reforming units do not have specific cycles, so the reference to “regeneration cycle” in the definition of these terms was ambiguous or meaningless for continuously regenerated catalytic reforming units. We are proposing to replace the phrase “regeneration cycle” with “regeneration cycle or measurement period” in the definition of the coke burn-off quantity and to revise the definition of “n” to be the “Number of regeneration cycles or measurement periods in the calendar year.” A measurement period may be a day, week, month, or other time interval

over which process measurements are made on the unit by which the coke burn-off rate is determined. We are similarly proposing to clarify 40 CFR 98.256(f)(13) (formerly designated 40 CFR 98.256(f)(12)) to require reporting of “* * * 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” when Equation Y-11 is used.

Calculating GHG Emissions From Sulfur Recovery Plants. With respect to requirements for sour gas sent off-site for sulfur recovery and for on-site sulfur recovery plants, we intended these requirements to be identical and that the petroleum refinery would report these emissions regardless of whether the sour gas feed is used at an on-site sulfur recovery plant within the refinery facility or the sour gas feed is sent to an off-site facility. However, we do note that the requirements were developed considering Claus sulfur recovery plants and that the methods in 40 CFR 98.253(f) may not be appropriate for all other types of sulfur recovery plants. To clarify the requirements for sulfur recovery plants, we are proposing to amend 40 CFR 98.253(f) 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 proposing to amend the reporting requirements in 40 CFR 98.256(h) to include the type of sulfur recovery plant and an indication of the method used to calculate CO₂ emissions as well as reporting requirements for non-Claus sulfur recovery plants that elect to follow the requirements in 40 CFR 98.253(j) for process vents. While we believe the calculation methodology needs no further regulatory text amendments, we do clarify in this preamble that the phrase “the sulfur recovery plant” in 40 CFR 98.253(f) refers to either the on-site or off-site sulfur recovery plant, as applicable. We further clarify in this preamble that the sour gas flow and carbon content measurements for sour gas sent off-site for sulfur recovery may be made at either the refinery or the off-site sulfur recovery plant provided these measurements are representative of the flow and carbon content of the sour gas sent off-site for sulfur recovery.

Calculating CO₂ Emissions From Coke Calcining Units. We are proposing to amend 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). It was brought to our attention that dust collected by the control systems may be recycled back to the coke calciner, raising the issue of how M_{dust} should be determined in this situation: Is it the mass of dust collected in the dust collection system or is it the mass of dust that is discarded from the system? The mass balance represented by Equation Y-13 should be applied external to this recycle loop, so that M_{dust} is the quantity of dust removed from the overall process, which would be the mass of the dust collected in the control system minus the mass of dust recycled. We are, therefore, proposing to amend the definition of M_{dust} in Equation Y-13 to clarify this interpretation of M_{dust} when all or a portion of the collected dust is recycled back to the coke calciner. We also are proposing to amend 40 CFR 98.256(i)(5) 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 proposing to amend the process vent requirements in 40 CFR 98.253(j) due to 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). This amendment clarifies that the emissions from the sources that elect to use the process vent method in 40 CFR 98.253(j), must use Equation Y-19 to calculate the emissions for the pollutants required to be reported under the cross-referencing section, regardless of whether the concentration thresholds in 40 CFR 98.253(j) are exceeded. We are also proposing to amend the definition of Equation Y-19's parameters of VR (the volumetric flow rate) and MF_x (the mole fraction of the GHG in the vent). For these parameters we are proposing to clarify that these values are to be determined "from measurement data, process knowledge, or engineering estimates." We are also proposing to amend the reporting requirements for process vents to clarify that the requirements apply to each process vent as well as to provide an indication of the measurement of estimation method.

Finally, we are proposing to amend 40 CFR 98.253(n) 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. We affirm

that process knowledge may be used to determine which loading operations have a vapor-phase concentration of methane of 0.5 volume percent, but this determination must be made considering both the material being loaded and the conditions of the loading operations. Equilibrium vapor-phase concentrations can be used as process knowledge to determine if the concentration of methane is 0.5 volume percent or more.

Monitoring and QA/QC Requirements. In subpart Y, 40 CFR 98.254 currently specifies QA/QC requirements for fuel flow meters, gas composition monitors, and heating value monitors that provide data for the GHG emissions calculations. A distinction is made in paragraphs (a) and (b) between measurement devices associated with stationary combustion sources, which are required to follow the QA/QC procedures in 40 CFR 98.34, and devices associated with other GHG emissions sources at the refinery, which are to be quality-assured according to 40 CFR 98.254(c) through (e). Paragraphs (f), (g), and (h) of 40 CFR 98.254 QA/QC requirements for:

- Stack gas flow rate monitors that are used to comply with the requirements of 40 CFR 98.253(c)(2)(ii);
- CO₂/CO/O₂ composition monitors used to comply with 40 CFR 98.253(c)(2); and
- Weighing devices that are used to measure the mass of petroleum coke when CO₂ emissions from a coke calcining unit are calculated using Equation Y-13.

In subpart Y, 40 CFR 98.254(l) provides QA/QC requirements for CO₂ CEMS and flow monitors used for direct measurement of CO₂ emissions following the Tier 4 methodology in subpart C.

We are proposing to amend 40 CFR 98.254(a) through (h), and (l) as follows, to make them consistent with today's proposed revisions to 40 CFR 98.3(i), and to make some necessary technical corrections and clarifications:

Paragraph (a) of 40 CFR 98.254 would be amended to also include the phrase "sources that use a CEMS to measure CO₂ emissions according to subpart C of this part * * *" to further separate these sources from those that are covered by 40 CFR 98.254(b). Although the CEMS monitoring requirements are specified in 40 CFR 98.254(l), these requirements are more clearly specified by the proposed amendments to 40 CFR 98.254(a) so that all sources required to meet the methods provided in subpart C are identified in a single paragraph. We also are proposing to re-word the phrase "follow the monitoring and QA/QC requirements in 40 CFR 98.34" with

"meet the applicable monitoring and QA/QC requirements in 40 CFR 98.34" to clarify that the monitors must meet the requirements for the specific Tier for which monitoring was required (Tier 3 sources would comply with the Tier 3 requirements; Tier 4 sources would 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) would be included in the amended paragraph 40 CFR 98.254(a), we are proposing to delete 40 CFR 98.254(l).

Paragraph (b) of 40 CFR 98.254 would be 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 would correct 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 would also clarify that the calibration requirements in 40 CFR 98.3(i) only apply to gas flow meters and to allow 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 would also be 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 would be 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 would be removed from 40 CFR 98.254(c), because the accuracy requirement for these flow meters is stated in the general provisions at 40 CFR 98.3(i) and is referenced in 40 CFR 98.254(b). We are also proposing to amend 40 CFR 98.254(c) by removing the list of methods as this is redundant with the existing phrase, "a method published by a consensus-based standards organization."

Paragraphs (d) and (e) of 40 CFR 98.254 would be 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; and the methods used for operation, maintenance, and calibration of the GC are documented in the written monitoring plan for the unit under 40 CFR 98.3(g)(5). Paragraph (d) in 40 CFR 98.254 would also be 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. This is needed to address gas composition monitors that may already be in place on process vents subject to reporting under 40 CFR 98.253(j), so that these monitors can use alternatives to the methods in 40 CFR 98.254(d).

We are also proposing to amend 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 proposing to add an additional method (ASTM D2503-92) to this section for determining average molecular weight. Methods for determining average molecular weight were inadvertently omitted from this section.

We are proposing a number of amendments to 40 CFR 98.254(f). First, the applicability of this paragraph would be expanded to include all gas flow meters on process vents subject to reporting under 40 CFR 98.253(j). The term "exhaust gas flow meter" would be replaced with the term "gas flow meter," because not all process vents that would report under 40 CFR 98.253(j) are combustion ("exhaust") related gas streams.

Subpart Y currently allows an option to follow 40 CFR 63.1572(c) (in the NESHAP for Petroleum Refineries) for installation, operation, and calibration of the stack gas flow rate monitor or the requirements in 40 CFR 98.254(f)(1) through (f)(4). In our review of these requirements, we found that 40 CFR 98.254(f)(1) and (f)(3) were important requirements that were not delineated in 40 CFR 63.1572(c). However, 40 CFR 98.254(f)(2) is not appropriate (accuracy requirements for these flow meters are already provided in the general provisions in 40 CFR 98.3(i) and are referenced in 40 CFR 98.254(b)), and 40 CFR 98.254(f)(4) is duplicative of the requirements in 40 CFR 63.1572(c).

We are proposing to retain portions of 40 CFR 98.254(f)(1) and (3), but only as general, supplementary guidelines for flow monitor installation and operation. Thus, we are proposing that these stack flow monitors must:

- 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 proposing to make a technical correction to 40 CFR 98.254(g). Subpart Y currently requires the CO₂/CO/O₂ composition monitors that are used to comply with the requirements of 40 CFR 98.253(c)(2) be installed, operated, maintained, and calibrated according to either 40 CFR 60.105a(b)(2) (in the NSPS for Petroleum Refineries) or 40 CFR 63.1572(a), or according to the manufacturer's specifications and requirements. The reference to 40 CFR 63.1572(a) was in error and should be 40 CFR 63.1572(c). In the NESHAP for Petroleum Refineries (40 CFR part 63 subpart UUU), these monitors are used to calculate coke burn-off rates, which are monitored to ensure the control device is operated within specified limits. Thus, these monitors are subject to 40 CFR 63.1572(c) within the NESHAP for Petroleum Refineries, and this is the level of QA that these monitoring systems are expected to be currently following. We note that CO₂ monitors that are certified and calibrated as CEMS (with the appropriate flow monitoring system) would be subject to the requirements in 40 CFR 98.253(c)(1), not 40 CFR 98.253(c)(2). Consequently, we specifically refer to the monitors within this 40 CFR 98.254(g) as "CO₂/CO/O₂ composition monitors" rather than CEMS to avoid confusion that these monitors must be operated according to CEMS requirements. In developing Part 98, we required CO₂/CO/O₂ composition monitors for catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day because these monitors were expected to be in-place to comply with the NESHAP for Petroleum Refineries. We did not include additional costs to upgrade the existing CO₂/CO/O₂ composition monitors in our impact analysis because we intended to use the same monitoring requirements as in the NESHAP for Petroleum Refineries. Therefore, we are proposing to amend 40 CFR 98.254(g) to refer to 40 CFR 63.1572(c), rather than 63.1572(a), for these O₂/CO/O₂ composition monitors.

Paragraph (h) of 40 CFR 98.254 specifies calibration procedures for weighing devices that are used to

determine the mass of petroleum coke fed to the coke calcining unit, as required by Equation Y-13. Subpart Y currently provides three calibration options: (1) Follow the procedures in NIST Handbook 44; (2) follow the manufacturer's recommended procedures; or (3) follow the procedures in 40 CFR 98.3(i). We are proposing to amend 40 CFR 98.254(h) to require calibration according to the procedures specified by NIST Handbook 44 or the procedures specified by the manufacturer. Note that the requirements of 40 CFR 98.3(i) for other measurement devices would apply as well.

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

We are proposing to amend the reporting requirements for Equation Y-1 (renumbered to Y-1a) and Y-2 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 proposing to amend the references to 40 CFR 98.36(e)(2)(vi) to reference 40 CFR 98.36 more generally. This would make the references consistent with the associated requirements in 40 CFR 98.253.

In our review of the reporting requirements in 40 CFR 98.256(f), we noted an inadvertent error in 40 CFR 98.256(f)(10) and (11) [which would be redesignated 40 CFR 98.256(f)(11) and (12) due to the proposed reporting requirement associated with Equation Y-7b]. In subpart Y, facility owners and operators are required to report information about unit-specific emission factors for CH₄ and N₂O, but not necessarily report the unit-specific emission factor itself. We are proposing to correct this inadvertent error and require direct 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 proposing to amend 40 CFR 98.256(i)(8) to make it consistent with the information collected in 40 CFR 98.245(i)(7).

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

We are also proposing to re-organize the reporting requirements in 40 CFR 98.256(o) to clarify, for example, that the reporting requirement in 40 CFR 98.256(o)(7) of Part 98 pertains specifically to tanks processing unstabilized crude oil.

O. Subpart AA (Pulp and Paper Manufacturing)

We are proposing to amend subpart AA in response to questions EPA received since Part 98 was published on October 30, 2009. These amendments are intended to provide clarification and ensure consistency with other parts of the rule.

EPA received questions regarding the methods specified in 40 CFR 98.273 to calculate fossil-fuel based CO₂ emissions from chemical recovery furnaces, chemical recovery combustion units, and pulp mill lime kilns. Specifically, clarification was requested as to whether an owner or operator can choose to use a tier other than Tier 1 from 40 CFR 98.33 to calculate fossil-fuel based CO₂ emissions. While it was our intent to provide this flexibility, the rule text indicated that only Tier 1 could be used. Therefore, we are proposing to amend 40 CFR 98.273(a)(1), (b)(1) and (c)(1) to clarify that owners and operators may use a higher tier. This flexibility in selecting tiers is consistent with 40 CFR 98.34. The option to use a higher tier to calculate fossil-fuel based emissions provides flexibility to reporters and it only affects the reporting requirements if an owner or operator chooses to use a higher tier. EPA also received questions regarding the prescribed emission factors to calculate fossil-fuel based CO₂ emissions from lime kilns. Specifically, 40 CFR 98.273(c)(1) directed owners and operators to use emission factors in Table AA-2 to calculate CO₂ emissions from lime kilns, but EPA has received requests to use the emission factors provided in Table C-1.

The emission factors in Table AA-2 were taken from "Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills", Version 1.1, July 8, 2005, which was prepared by the National Council for Air and Stream Improvement (NCASI) for the National Council of Forest and Paper Associations (ICFPA). Part 98 incorporated these factors in Table AA-2 because they were developed specifically for pulp and paper lime kilns, which operate at different conditions than other general stationary combustion units.

Upon further consideration, we have determined that the emission factors provided in Table AA-2 are uniquely suited for calculating CH₄ and N₂O emissions from lime kilns given these emissions are significantly influenced by the operating conditions. However, EPA has found that the same rationale does not support having unique emission factors to calculate CO₂

emissions from lime kilns. Therefore, EPA has removed the CO₂ emission factors from Table AA-2 and, in 40 CFR 98.273(c)(1), has directed owners and operators to use the CO₂ emission factors from Table C-1 of subpart C to calculate CO₂ emissions from lime kilns. Modifications to Table AA-2 would affect the emissions reported in 2010, but would not affect the data that are collected to report emissions in 2010.

Related to the calculation of CH₄ and N₂O emissions described above, and consistent with the proposal to allow use of higher Tiers than Tier 1 for units subject to subpart AA, EPA is proposing to allow reporters to also use site-specific high heating values, as opposed to default values, when calculating CH₄ and N₂O emissions.

EPA has also received questions from owners and operators about whether pulp and paper mills are required to calculate emissions from the combustion of their wastewater treatment sludge. Specifically, they asked for clarification of whether this type of sludge was included in Table C-1 and, if not, should they account for emissions from the combustion of this material. In our efforts to address this question, we have not been able to identify emission factors developed specifically for sludge from a pulp and paper mill wastewater facility. However, our research indicates that the content of 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 proposing to add the definition of "Wood and Wood Residuals" to 40 CFR 98.6 and to include wastewater process sludge from paper mills in this definition. Clarifying that emissions from the combustion of sludge from pulp and paper mill wastewater treatment facilities may be calculated using Tier 1 would require that owners and operators estimate the volume of sludge combusted using company records. Given the broad definition of company records, owners and operators should be able to develop estimates to report these emissions in 2011. Presuming these changes are finalized as proposed, they would be incorporated into annual GHG reports due in March 2011.

Finally, EPA received questions regarding which emission factors to apply when a pulp and paper mill combusts solid petroleum coke given this fuel type was not included in Table C-1 and Table AA-2. In response, we are proposing to add this fuel type to

both tables. However, it is noted that emission factors for petroleum coke specific to kraft calciners were not available. EPA does not believe that any kraft calciners are combusting petroleum coke, so we have concluded that it is not necessary to have emission factors for this fuel in Table AA-2. EPA seeks comment on this conclusion. Further, if information is provided that petroleum coke is combusted at kraft calciners, please also include any information on default CH₄ and N₂O emission factors.

P. Subpart NN (Suppliers of Natural Gas and Natural Gas Liquids)

Threshold for natural gas local distribution companies. The applicability provision in subpart A at 40 CFR 98.2(a)(4)(iii)(B) requires all natural gas local distribution companies (LDCs), regardless of size, to report the GHG emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end users on their distribution systems. Owners and operators of LDCs potentially subject to subpart NN have asserted that this provision results in an unfair burden on many small LDCs.

They have stated that requiring all LDCs to report did not adequately balance rule coverage of GHGs reported, while excluding small entities. For example, they highlighted data from the Energy Information Administration that indicated that 82 percent of facilities are estimated to deliver less than 460,000 mscf per year of natural gas, which is equivalent to approximately 25,000 mtCO₂e. They further noted that EPA's own estimates suggest that these facilities would be responsible for less than 1 percent of the reported GHG emissions associated with LDC supply. The owners and operators concluded that this is a disproportionate burden for LDCs, particularly if one considers that across the rule, applying a 25,000 mtCO₂e threshold would exclude approximately 10 to 15 percent of GHG emissions, a much larger percentage of emissions than would be excluded under LDCs by applying that same 25,000 mtCO₂e threshold.

The owners and operators noted that inclusion of all LDCs in the rule would also impose numerous reporting and recordkeeping requirements, even though most of these facilities would actually be eligible to stop reporting in three or five years, after they could prove to EPA that emissions from their supply were less than 15,000 mtCO₂e or 25,000 mtCO₂e per year, respectively.

We note that the threshold requirements for LDCs did not change

between the initial proposal in April 2009 and Part 98 promulgated on October 30, 2009. Further, EPA did not receive any comments opposed to the “all in” designation for LDCs during the public comment period on the proposed Part 98 and, in fact, received two comments supporting the lack of a threshold of any kind. Therefore, EPA retained in Part 98 the provision to require all LDCs to report the CO₂ emissions associated with their supply. EPA retained the provision in order to maximize coverage of the GHG emissions from natural gas supplies, and also to be consistent with other suppliers of fossil fuels and industrial gases covered by Part 98. An “all in” threshold was applied to all of these supplier categories.

Although we believe that the public had ample opportunity to comment on the threshold for LDCs, we have reevaluated this issue in light of the information received. We are proposing to amend 40 CFR 98.2(a)(4)(iii)(B) in subpart A to require all LDCs that deliver 460,000 mscf or more of natural gas per year to report. We are proposing this capacity-based threshold because a capacity-based threshold would be more familiar to LDCs. Owners and operators of LDCs know how much natural gas they deliver to their customers and it would, therefore, be easier for facilities to determine if they are subject to the rule than if the threshold were emissions-based. The proposed annual threshold is approximately equivalent to 25,000 mtCO₂e.

After further consideration, we have concluded that although a threshold would result in a loss of emissions information to EPA, the emissions coverage lost is less than 1 percent. It is also true that most of these facilities 460,000 mscf would be able to stop reporting to EPA in three or five years, raising the question of whether the burden associated with instituting a reporting program that includes the smaller facilities is necessary. We have determined that EPA and other stakeholders would be able to use data from external sources (e.g., the Energy Information Administration) to estimate the less than 1 percent of GHG emissions that would no longer be reported to EPA if a 460,000 mscf annual threshold were applied. This would minimize any concerns that the loss of emissions coverage would inhibit the use of the data for future policy making. Finally, we have concluded that LDCs are unique among suppliers in that a large majority of facilities would be under a 460,000 mscf threshold, and collectively these facilities are responsible for a relatively

low percentage of emissions from the industry.

Q. Subpart OO (Suppliers of Industrial Greenhouse Gases)

We are proposing several changes to subpart OO to (1) respond to concerns raised by producers of fluorinated GHGs regarding the scope of the monitoring and reporting requirements, and (2) 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 (1) 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, (2) are produced and transformed at the same facility, or (3) occur as low-concentration constituents (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.

Regarding fluorinated GHGs that are emitted or destroyed before the product is packaged for sale, the producers specifically requested that EPA amend subpart OO to remove the requirements of 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 40 CFR 98.413(a) because they are removed from the production process as byproducts or wastes.

They noted that measuring the flow of such fluorinated GHGs into the destruction device to the precision required (1 percent) posed significant technical challenges and that such measurement was outside the scope of subpart OO. They further stated that subpart OO was intended to address the quantities of fluorinated GHGs exiting production units and entering commerce, where commerce includes the packaging and marketing or import and export of fluorinated GHGs. They stated that the proposed subpart L was the more appropriate vehicle for the monitoring and reporting of emissions and destruction of fluorinated GHGs still within the production process.

However, the producers noted that it was practical and appropriate under subpart OO to measure the quantities of fluorinated GHGs that are returned to the production facility for destruction after entering into commerce (e.g., because they have become irretrievably contaminated).

Regarding fluorinated GHGs that are produced and transformed at the same facility, the fluorinated GHG producers noted that these fluorinated GHGs never enter the U.S. supply of fluorinated GHGs because they never leave the facility where they are produced. Thus, it is not necessary to track them under subpart OO.

Regarding fluorinated GHGs that occur as low-concentration constituents of fluorinated GHG products, the producers observed that such low-concentration constituents generally consist of by-products that are packaged along with the main constituent of the product. They noted that exempting the production, import, and export of these low-concentration constituents from monitoring and reporting requirements would be consistent with the exemption of “trace” concentrations from other monitoring requirements in subpart OO, such as 40 CFR 98.414(f) and (h).

In response to the concern regarding fluorinated GHGs that are emitted or destroyed before the product is packaged for sale, we are proposing (1) to modify 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);” (2) to remove 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 40 CFR 98.413(a) because they are removed from the production process as byproducts or wastes;” and (3) to modify the requirements at 40 CFR 98.414(h) and 98.416(a)(3) to limit them to “the mass of each fluorinated GHGs that is fed into the destruction device and that was previously produced as defined at § 98.410(b).”

These proposed amendments would clarify that the scope of subpart OO is that which EPA has always intended, and they would 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. To clarify this in the regulatory text, we are proposing to amend the definition of “produce a fluorinated GHG” at 40 CFR 98.410(b) to exclude the “creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at § 98.414(a).”

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). As noted above, emissions upstream of the production measurement would be subject to proposed subpart L and are not part of the subpart OO source category.

We are also proposing to amend 40 CFR 98.416(a)(3) to limit the monitoring and reporting of destroyed fluorinated GHGs to those destroyed fluorinated GHGs that were previously “produced” under today’s revised definition.⁴ 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,⁵

⁴ 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.

⁵ 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 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.

monitoring of quantities 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 proposing to (1) amend 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;” (2) amend the definition of “produce a fluorinated GHG” 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;” (3) add a definition of “isolated intermediate;” and (4) add 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 proposing to exclude the latter from the definition of “produce a fluorinated GHG,” we are proposing to include the former in that definition. This is because the manufacture of isolated intermediates, which can lead to emissions of those intermediates, is of interest under subpart L, and we would like 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 proposing to add provisions to exclude it from the subpart OO monitoring, reporting, and recordkeeping requirements. We are also proposing to add a definition of “isolated intermediate” that is the same as that proposed for subpart L (75 FR 18652, April 12, 2010).

In response to the concern regarding fluorinated GHGs that occur as low-concentration constituents of

fluorinated GHG products, we are proposing to define and exclude 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 proposing to define low-concentration constituent 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 (AHRI 700), for SF₆ used as an insulator in electrical equipment (IEC 60376), and for perfluorocarbons and other fluorinated GHGs used in electronics manufacturing (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 under 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 under 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 also proposing product sampling and analytical requirements at 40 CFR 98.414(n) and corresponding calibration requirements at 40 CFR 98.414(o).

For purposes of fluorinated GHG import, we are proposing to define low-concentration constituent 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 proposing 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 GWP's listed in Table A-1, we are proposing (1) to exempt such compounds from the general subpart A requirement to report supply flows in terms of CO₂ equivalents and (2) to recast the reporting exemptions for import and export of small shipments 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.G of this preamble. The exemptions for import and export would 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 would enable small shipments of fluorinated GHGs to be exempt from reporting regardless of whether or not the fluorinated GHG had a GWP listed in Table A-1. Our analysis of import and export data indicates that this change would slightly increase both the number and total mass of the imports and exports reported under the rule, but this analysis does not account for fluorinated GHGs whose GWP's are not listed in Table A-1. If those fluorinated GHGs were accounted for, we believe that the level of reporting would increase even less and might even decrease slightly.

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

We are proposing to amend 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 proposing to amend 40 CFR 98.416(b) and (e) to clarify the due dates of the one-time reports required by those paragraphs. The proposed 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 April 1, 2011, and there was no provision for commencing fluorinated GHG destruction or production after that date. The proposed amendments will make the due dates in 40 CFR 98.416(b) and (e) consistent with each other, with the due date for a similar report required in subpart O, and with the due date for other reporting under the rule.

We are proposing to amend 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 proposing to amend 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 proposing to amend 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.”

R. Subpart PP (Suppliers of Carbon Dioxide)

In subpart PP, we are proposing to remove the words “each” from the list of GHGs to report in 40 CFR 98.422. This change would align this section with the requirements of the rest of subpart PP, which allow for monitoring of an aggregated flow of CO₂ if it is done at a gathering point downstream of individual production wells or production process units.

We are proposing to allow those suppliers that supply CO₂ in containers 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. As a result of many questions received during outreach in support of alternative procedures for CO₂ supplied in containers, we have reevaluated the calculation procedures for CO₂ suppliers. We have concluded that measurements made with weigh bills, scales, load cells, or loaded container volume readings will continue to meet the level of data quality and accuracy needed by EPA with respect to subpart PP. We have reached this conclusion with consideration to minimizing the burden on and maximizing the flexibility provided to industry.

We are proposing multiple amendments to the regulatory text to accommodate this proposed provision. First, we are proposing that 40 CFR 98.423(b) be renumbered to 40 CFR 98.423(c) and that a new 40 CFR 98.423(b) be added with calculation procedures for CO₂ supplied in containers. Second, we are proposing to amend the first sentence of 40 CFR 98.423(a) to allow suppliers that supply CO₂ in containers to use the alternative procedures in 40 CFR 98.423(b). Third, we are proposing to add new QA/QC procedures for suppliers that supply CO₂ in containers to 40 CFR 98.424(a). Fourth, we are proposing to add missing data procedures for suppliers that supply CO₂ in containers to 40 CFR 98.425(d). Finally, we are proposing to

make 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 note that under the existing requirements, importers and exporters that import and export CO₂ in containers must measure the mass of CO₂ in containers using weigh bills, scales, or load cells. In this action, we are not proposing that the use of loaded container volume readings be allowed for such reporters as an alternative to weigh bills, scales, or load cells because we have received no questions from importers or exporters suggesting the need for such an allowance. We seek comment on whether such an allowance should be extended to importers and exporters of CO₂ in containers, and if so whether the calculation procedures, QA/QC procedures, missing data procedures, and reporting requirements for loaded container volume readings proposed in this action for suppliers should be offered to importers and exporters.

We are proposing to remove 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 proposing to redesignate as 40 CFR 98.423(c)). This provision created confusion and conflict over where to place a flow meter. For example, at least one reporter has indicated that only a portion of a CO₂ stream is transferred for commercial application while the rest is retained for onsite use and emission, and this portion of the stream is segregated only after processing. As a result of this and other concerns that the requirement to install flow meters prior to purification, processing, or compression could result in a requirement to install the flow meter at a technically infeasible point, we reevaluated the value of such a constraint on the CO₂ calculations. Since 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 proposing to add language at 40 CFR 98.424(a) requiring the flow meter to be located after the point of segregation. We are also proposing to amend existing language in 40 CFR 98.424(a) to reference this new requirement.

Because the proposed amendments would allow flow meters to be located after purification, compression, or processing, we are proposing to add data reporting requirements in 40 CFR 98.426 to collect additional information on flow meter location. Specifically, we are proposing that facilities would 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 and to learn about the efficacy of various CO₂ stream capture processes.

The current subpart PP regulatory text requires that a reporter using a volumetric flow meter to measure the flow of a CO₂ stream measure density of that CO₂ stream in order to calculate the mass of CO₂ supplied. As a result of new analysis, we have concluded that the mass of CO₂ in a stream can be adequately determined by converting the volumetric flow of CO₂ 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. This approach may also be less burdensome for reporters than directly measuring density with equipment. Therefore, we are proposing to amend 40 CFR 98.424(a)(5) by replacing the word “measure” with the word “determine.”

We are also proposing to add a new paragraph 40 CFR 98.424(c) so that suppliers will be able to calculate the mass of CO₂ in a stream from the measured volumetric flow (converted to standard conditions) and CO₂ concentration, and the given density of CO₂ at standard conditions.

For the calculation in the proposed paragraph 40 CFR 98.424(c), standard conditions under subpart PP would be a temperature and an absolute pressure of 60°F and 1 atmosphere. Note that this would be different than the standard conditions defined in subpart A (40 CFR 98.6), which are 68°F and 14.7 psia. 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, and we seek comment on this conclusion. Given these conditions, we are

proposing that reporters must use 0.0018704 metric tons per standard cubic meter as a density value for CO₂ at standard conditions if this is the industry standard practice used to determine density.

The current subpart PP regulatory text also requires that an appropriate method published by a consensus-based standards organization be used to measure density if such a method exists. Where no such method exists, an industry standard practice must be followed. We have been unable to identify any method published by a consensus-based standards organization that accounts for the approach for determining density described above and have concluded that it would be categorized as an industry standard practice. Therefore, we are proposing to amend language in 40 CFR 98.424(a)(5) and (a)(5)(ii) to allow reporters to choose equally from between a method published by a consensus-based standards organization that is appropriate or an industry standard practice to determine density.

We are proposing to amend 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.

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 (EO) 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under the EO.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. These proposed amendments do not make any substantive changes to the reporting requirements in any of the subparts for which amendments are being proposed. In many cases, the proposed amendments to the reporting requirements could potentially reduce the reporting burden by making the reporting requirements conform more closely to current industry practices. 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. 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 this proposed rule 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 proposed 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 proposed rule amendments will not impose any new requirement on small entities that are not currently required by the rules promulgated on October 30, 2009 (*i.e.*, calculating and reporting annual GHG emissions).

EPA took several steps to reduce the impact of Part 98 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.

We continue to be interested in the potential impacts of the proposed rule amendments on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

This proposed rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. EPA has estimated that, overall, the proposed revisions do not significantly change the overall costs of compliance with Part 98. The proposed amendments include providing additional flexibility for reporters, clarifying existing reporting requirements, and requiring reporting of information already required to be collected under Part 98. EPA estimates that the cost for all reporters in reviewing the proposed rule and determining if, and if so how, it applies to their facility, is approximately \$2.5 million in the first year. Considering the additional flexibilities proposed, in sum, EPA has estimated that the proposed rule, if finalized, would reduce the burden to reporters as compared to the 2009 final rule. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA. For more information on the cost analysis, please refer to the memorandum titled "Mandatory Greenhouse Gas Reporting: Changes in National Cost Estimates Associated with the Proposed Notice of Revisions" found in the docket at (EPA-HQ-OAR-2008-0508).

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. EPA determined that the proposed 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 rules published on October 30, 2009 (*i.e.*, calculating and reporting annual GHG emissions). EPA concluded in the preamble to that final rule that the rule "* * * contains no regulatory requirements that might significantly or uniquely affect small governments" (40 CFR 56260). Because the final rule was not determined to significantly or uniquely affect small governments, and because this proposed rule generally reduces the burden associated with the 2009 final rule, these rule amendments

would not unfairly apply to small governments.

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 proposed rule amendments would relate to existing State programs, *please see* Section II of the proposal preamble for Part 98 (74 FR 16457 to 16461, April 10, 2009).

These amendments apply directly to facilities that supply fuel or chemicals 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 large stationary combustion source), so relatively few government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this 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 Part 98. A summary of EPA's consultations with State and local governments is provided in Section VIII.E of the preamble to the final Part 98 (74 FR 56260, October 30, 2009).

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

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 proposed rule amendments would not result in any changes to the requirements of the 2009 rule. 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 Part 98 (74 FR 56260, October 30, 2009).

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

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

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

This action is not 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 No. 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 proposed rulemaking involves technical standards. No new test methods were developed for this proposed rule; rather, EPA identified existing means of monitoring, reporting, and keeping records of greenhouse gas emissions. EPA proposes to use two additional voluntary consensus standards from ASTM International. Part 98 includes the use of over 40 voluntary consensus standards from various consensus standards bodies, for example, ASTM International, the American Society of Chemical Engineers, Gas Processors Association, the American Gas Association, and the American Petroleum Institute. The proposed addition of these two

voluntary consensus standards from ASTM International to Part 98 will help petroleum refineries and petrochemical facilities monitor, report, and keep records of greenhouse gas emissions. The test methods are incorporated by reference into the proposed rule and are available as specified in proposed amendments to 40 CFR 98.7.

By incorporating voluntary consensus standards into this proposed rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring greenhouse gas emissions.

EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

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

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

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

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: July 20, 2010.

Lisa P. Jackson, Administrator.

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

PART 98—[AMENDED]

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

Authority: 42 U.S.C. 7401, et seq.

Subpart A—[Amended]

2. Section 98.2 is amended by revising paragraph (a)(4)(iii)(B) to read as follows:

§ 98.2 Who must report?

- (a) * * *
(4) * * *
(iii) * * *

(B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.

- 3. Section 98.3 is amended by:
a. Revising paragraphs (c)(1), (c)(4)(i), (c)(4)(ii), (c)(4)(iii) introductory text, (c)(4)(iii)(A), (c)(4)(iii)(B), and (c)(5)(i).
b. Revising the third sentence of paragraph (d)(3) introductory text.
c. Revising the first sentence of paragraph (f).
d. Revising paragraphs (g)(4), (g)(5)(iii).
e. Revising paragraph (h).
f. Revising paragraph (i).
g. 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), facility or supplier ID number, and physical street address of the facility or supplier, including the city, state, and zip code.

- (4) * * *

(i) Annual emissions (including biogenic CO2) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO2e calculated using Equation A-1 of this subpart.

(ii) Annual emissions of biogenic CO2 aggregated for all applicable source categories in subparts C through JJ of this part in metric tons. Units that use the methodologies in part 75 of this chapter to calculate CO2 mass emissions are not required to separately report biogenic CO2 emissions, but may do so as an option.

(iii) Annual emissions from each applicable source category in subparts C through JJ of this part, expressed in metric tons of each applicable GHG listed in this paragraph (4)(iii)(A) through (4)(iii)(E).

(A) Biogenic CO2. Units that use the methodologies in part 75 of this chapter to calculate CO2 mass emissions are not required to separately report biogenic CO2 emissions, but may do so as an option.

(B) CO2 (including biogenic CO2).

* * * * *

(5) * * *
(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO2e calculated using Equation A-1 of this subpart. For fluorinated GHGs, calculate and report CO2e for only those fluorinated GHGs 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 and 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 industry standards and manufacturer's specifications. 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 an industry consensus standards or a manufacturer's specification.

(C) You must document the methods used for the demonstration described in paragraph (i)(3)(ii)(A) of this section in the written 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 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 Monitoring Plan and recordkeeping provisions of paragraphs (g)(5)(i)(C) 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 or ignition 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.

4. 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.

* * * * *

5. Section 98.6 is amended by:

a. Adding in alphabetical order definitions for "Agricultural byproducts," "Primary fuel," "Solid byproducts," "Waste oil," and "Wood residuals."

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

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

§ 98.6 Definitions.

* * * * *

Agricultural byproducts means those parts of arable crops that are not used for the primary purpose of producing food. Agricultural byproducts 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.

* * * * *

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 waste does not include used oil, wood pellets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials, limited to vehicle batteries and tires, except where a single waste stream consisting of tires is combusted in a unit.

* * * * *

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 is composed of at least 70 percent methane by volume or has a high heat value between 910 and 1150 Btu per standard cubic foot.

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

* * * * *

Waste oil means a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of storage, handling or use, such that the oil cannot be used for its original purpose. Waste 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 wood waste 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, and logging residues.

* * * * *

- 6. Section 98.7 is amended by:
 - a. Removing and reserving paragraph (b).
 - b. Revising paragraphs (d)(1) and (d)(2).
 - c. Removing and reserving paragraph (d)(3).
 - d. Revising paragraphs (d)(4) and (d)(5).
 - e. Removing and reserving paragraph (d)(6).
 - f. Revising paragraphs (d)(7) and (d)(8).
 - g. Removing and reserving paragraph (d)(9).
 - h. Revising paragraph (d)(10).
 - i. Removing and reserving paragraph (d)(11).
 - j. Revising paragraph (e)(4).
 - k. Removing and reserving paragraph (e)(7).
 - l. Revising paragraphs (e)(8), (e)(10), (e)(11), (e)(14), (e)(15), (e)(19), (e)(20), (e)(24) through (e)(27).
 - m. Removing and reserving paragraph (e)(28).
 - n. Revising paragraph (e)(30), (e)(33), and (e)(36).
 - o. Adding paragraphs (e)(43) and (e)(44).

- p. Removing and reserving paragraph (f)(1) and (g)(3).
- q. Revising paragraph (f)(2)
- r. Removing and reserving paragraph (g)(3).
- s. Adding paragraph (m)(3).

§ 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 § 98.344(c) and § 98.364(e).
 - (2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for § 98.344(c) and § 98.364(e).
 - (3) [Reserved]
 - (4) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 98.344(c) 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 § 98.344(c) and § 98.364(e).
 - (6) [Reserved]
 - (7) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 98.344(c).
 - (8) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 98.344(c) and § 98.364(e).
 - (9) [Reserved]
 - (10) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 98.344(c), and § 98.364(e).
 - (11) [Reserved]
 - (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).
 - (7) [Reserved]
 - (8) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for § 98.254(e).
 - (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), 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), § 98.344(b), 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).

* * * * *

(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).

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

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

(28) [Reserved]

* * * * *

(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), § 98.224(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).

* * * * *

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

(44) ASTM D2593–93(2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, IBR approved for § 98.244(b).

* * * * *

(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), and § 98.344(b).

* * * * *

(g) [Reserved]

* * * * *

(k) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, D.C. 20460, (202) 272–0167, www.epa.gov.

(1) Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, EPA–430–R–10–003.

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 permanent 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 paragraphs (a) introductory text and (a)(1).

b. Revising the definition of “HHV” in Equation C–2a of paragraph (a)(2)(i).

c. Revising and 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” and “MW” in Equation C–5 of paragraph (a)(3)(iii).

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

h. Adding a new 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), (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 paragraph (b)(1)(v).

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 a new paragraph (b)(4)(iv).

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

s. In paragraph (c)(1), revising the second sentence, and revising the definition of “HHV” in Equation C–8.

t. Revising the second sentence of paragraph (c)(2).

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

v. Revising paragraphs (c)(4)(i) and (c)(4)(ii).

w. Adding a new paragraph (c)(6).

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

y. Revising paragraphs (d)(2), (e) introductory text, (e)(1), and (e)(2) introductory text.

z. Revising the definition of "F_c" in Equation C-13 of paragraph (e)(2)(iii).

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

bb. Reserving paragraph (e)(4).

cc. Revising the first sentence of 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 or C-1a 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. In that case, use Equation C-1a.

CO₂ = 1 × 10⁻³ * Fuel * HHV * EF (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.

CO₂ = 1 × 10⁻³ [0.1 * Gas * EF] (Eq. C-1a)

Where:

CO₂ = Annual CO₂ mass emissions from natural gas combustion (metric tons).

Gas = Annual natural gas consumption, 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.

(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", 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 be computed 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.

* * * * *

(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. For liquid fuels, you must measure the density using one of the following appropriate methods. You may use a method published by a consensus 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, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

Alternatively, for fuel oil, you may use

an applicable default density value provided in paragraph (a)(3)(v) of this section. For gaseous fuels, you may determine the density using any of the following methods. You may use a density meter calibrated according to the manufacturer's instructions, a method published by a consensus standards organization, or an industry standard practice. Document the method used to determine the fuel density in the Monitoring Plan under § 98.3(g)(5).

* * * * *

(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 as 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. 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. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. 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, provided that the CO₂ concentration in the diverted stream is not altered in any way (e.g., by chemical reaction or dilution) before the diverted stream exits to the atmosphere, an estimate of the hourly average volumetric flow rate (scfh) of the diverted gas stream shall be made at the point where it exits the main exhaust system, by using the best available information (e.g., correlations of operating parameters versus flow measurements made with EPA Method 2 in appendix A-2 to part 60 of this chapter, engineering analysis, or other methods). Each hourly average volumetric flow rate (scfh) measured at the main flue gas stack shall then be added to the corresponding estimate of the hourly average flow rate of the diverted gas stream, to determine the total hourly average stack gas volumetric flow rate "Q", for use in Equation C-6 of this section. The method use to estimate the hourly flow rate of 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.

(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) and (b)(1)(v) 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.

(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 all of 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 either 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 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).

* * * * *

(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.

* * * * *

(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-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 MWs.

* * * * *

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, separate reporting of biogenic CO₂ emissions is optional 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. 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.

(4) [Reserved]

(5) 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. * * *

* * * * *

10. Section 98.34 is amended by:

- a. Revising paragraphs (a)(2), (a)(3), (a)(6), (b)(1) introductory text, (b)(1)(i) introductory text, (b)(1)(i)(A), (b)(1)(i)(B), (b)(1)(i)(C), (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), and (f)(5).

h. Adding new 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. For the purposes of this section, a fuel lot is defined as either:

(A) A shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.); or

(B) 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 are considered, collectively, to comprise a fuel lot, requiring only one representative sample.

(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, 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), 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.

$$(EF)_B = \frac{\sum_{i=1}^n [(HHV)_i (\%Fuel)_i (EF)_i]}{(HHV)_B} \quad (\text{Eq. C-16})$$

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.

$$HHV_B^* = \sum_{i=1}^n [(HHV)_i (\%Fuel)_i] \quad (\text{Eq. C-17})$$

Where:

(HHV)_B^{*} = Heat-weighted default high heat value for the blend (mmBtu per mass or Volume)

(HHV)_i = Default high heat value for fuel “i” in the blend, from Table C-1 (mmBtu per mass or volume)

(%Fuel)_i = Estimated mass or volume percentage of fuel “i” in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

(iv) If the fuel blend described in paragraph (a)(3)(ii) of this section consists of a mixture of fuel(s) listed in Table C-1 of this subpart and one or more fuels not listed in Table C-1, calculate 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. You may use a method published by a consensus standards organization if such a method exists, or you may use industry consensus standard practice to determine the high heat values. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). Alternatively, for gaseous fuels, 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. 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 an appropriate flow meter calibration method published by a consensus standards organization, if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American

Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(B) You may use the calibration procedures specified by the flow meter manufacturer.

(C) You may use an industry-accepted or industry consensus standard calibration 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) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by industry consensus 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) 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 or ignition 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. For the purposes of this section, a fuel lot is defined as either of the following:

(1) A shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.).

(2) 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 are considered, collectively, to comprise a fuel lot, requiring only one representative sample.

(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. You may use a method published by a consensus standards organization if such a method exists, or you may use industry consensus 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, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). 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. 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) Sections 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) 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 consecutive hours or for as long as is deemed necessary to obtain a representative sample. One suggested alternative sampling approach would be 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 and ASTM D7459-08 may be used to determine the biogenic portion of the CO₂ emissions. Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Collect each gas sample using ASTM D7459-08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a representative sample. If the types of fuels combusted in the unit and their relative proportions are not consistent throughout the quarter, more frequent, periodic sampling of the flue gas should be considered. For example, an integrated sample could be collected by extracting a small amount of the flue gas (*e.g.*, 1 to 5 cc) in each unit operating hour of the quarter. If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(f) The records required under § 98.3(g)(2)(i) shall include an explanation of how the following parameters are determined from company records (or, if applicable, from the best available information):

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies

are used, including cases where § 98.36(c)(4) applies.

* * * * *

(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.

* * * * *

(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 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. Adding newly designated paragraphs (b)(8) and (b)(9).
- e. Adding new paragraphs (b)(6) and (b)(7).
- f. Revising paragraphs (c)(1)(ii), (c)(1)(vi), and (c)(1)(vii).
- g. Redesignating paragraph (c)(1)(viii) as paragraph (c)(1)(x), and revising newly designated paragraph (c)(1)(x).
- h. Removing paragraph (c)(1)(ix).
- i. Adding new paragraphs (c)(1)(viii) and (c)(1)(ix).
- j. Revising paragraphs (c)(2) introductory text, (c)(2)(ii), (c)(2)(iii), and (c)(2)(v).
- k. Removing paragraph (c)(2)(viii).
- l. 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).
- m. Adding new paragraphs (c)(2)(vi) and (c)(2)(vii).

n. Revising paragraphs (c)(3) introductory text, (c)(3)(ii), (c)(3)(iii), and (c)(3)(vii).

o. Removing paragraph (c)(3)(viii).
p. Adding new paragraphs (c)(3)(viii), (c)(3)(ix), and (c)(4).

q. Revising paragraph (d).
r. Revising paragraphs (e)(1)(iii), (e)(2)(i), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iii), and (e)(2)(iv)(A), (e)(2)(iv)(C).
s. Adding new paragraphs (e)(2)(iv)(F) and (e)(2)(v)(E).

t. Revising paragraphs (e)(2)(vii)(A), (e)(2)(ix) introductory text, and (e)(2)(x) introductory text.

u. Removing paragraphs (e)(2)(x)(B) and (e)(2)(x)(C).

v. Redesignating paragraph (e)(2)(x)(D) as (e)(2)(x)(B), and revising newly designated paragraph (e)(2)(x)(B).

w. 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) If the total annual CO₂ mass emissions measured by the CEMS 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) The number of units in the group.

* * * * *

(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 both combustion products and process off-gases, and all of the effluent comes from a single unit (*e.g.*, a furnace, kiln, 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 liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of 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. For Tier 3 applications, the flow meter shall be calibrated in accordance with § 98.34(b). If a portion of the fuel measured 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 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:

* * * * *

(ii) The number of units served by the common pipe.

(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 situations where 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 small combustion sources on-site, including but not limited to space heaters and hot water heaters. 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 on-site, 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. Reporting of biogenic CO₂ emissions under § 98.3(c)(4)(ii) and § 98.3(c)(4)(iii)(A) is optional. Subpart D units are not required to report biogenic CO₂ emissions under §§ 98.3(c)(4)(ii) and (c)(4)(iii)(A).

(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 (optional).

(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 (optional).

(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 (optional).

(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 or, if applicable, therms for gaseous fuels.

(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).

(v) * * *

(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 and D6866-08 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 and D6866-08 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 of Supart C of Part 98 is amended by:

- a. Revising the title to read “Table C–1 to Subpart C—Default CO₂ Emission Factors and High Heat Values for Various Types of Fuel.”
- b. Revising the entry for “Pipeline (Weighted U.S. Average).”
- c. Removing the entry for “Still Gas.”
- d. Adding an entry for “Waste Oil” to follow the entry for “Residual Fuel Oil No. 6.”
- e. Adding an entry for “Ethanol” to follow the entry for “Ethane.”

- f. Revising the entry for “Fossil fuel-derived fuels (solid).”
- g. Revising the entry for “Municipal Solid Waste.”
- h. Adding entries for “Plastics” and “Petroleum Coke” to follow the entry for “Tires.”
- i. Revising the entry for “Fossil fuel-derived fuels (gaseous).”
- j. Adding entries for “Propane Gas” and “Fuel Gas” to follow the entry for “Coke Oven Gas.”

- k. Revising the entry for “Biomass fuels—solid.”
- l. Revising 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 a new 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.
Waste Oil	0.135	74.00.
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.
Biomass fuels—solid	mmBtu/short ton	kg CO ₂ /mmBtu.
Ethanol	0.084	68.44.
Biodiesel	0.128	73.84.

¹ Use of this default HHV is allowed only for units that combust MSW, do not generate steam, and are allowed to use Tier 1.

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, Tier 3 (Equation C–5) or Tier 4 must be used.

14. The first Table C–2 is removed, and the second Table C–2 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 1 g 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 98.46 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).

17. 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]

18. 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.

* * * * *

19. 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.

* * * * *

20. 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 one year after publication of the rule for smelters with no prior measurement or effective three years after publication 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), 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.

* * * * *

21. 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.

* * * * *

22. 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 Søderberg electrolysis cells combined.

* * * * *

23. In the table to Supart F of Part 98, revise Table F-1 to read as follows:

TABLE F-1 TO SUBPART F—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 Soderberg (VSS)	0.092	NA	0.053
Horizontal Stud Soderberg (HSS)	0.099	NA	0.085

24. Table F-2 is amended by revising the entry for “CO₂ Emissions from Pitch Volatiles Combustion (VSS and HSS)” to read as follows:

TABLE F-2 TO SUBPART F—DEFAULT DATA SOURCES FOR PARAMETERS USED FOR CO₂ EMISSIONS

Parameter	Data source
CO₂ Emissions from Prebake Cells (CWPB and SWPB)	
*	*
CO₂ Emissions from Pitch Volatiles Combustion (CWPB and SWPB)	
*	*

Subpart G—[Amended]

25. 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).

* * * * *

26. 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)).

27. Section 98.74 is amended by revising paragraph (d) and by removing and reserving paragraph (f) to read as follows:

§ 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).

* * * * *

28. 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.

29. 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 a new paragraph (b)(13).
- d. 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).

* * * * *

(12) Annual urea production (metric tons) and method used to determine urea production.

(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]

30. Section 98.164 is amended by revising paragraph (b)(1) 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).

* * * * *

Subpart V—[Amended]

31. Section 98.226 is amended by removing paragraph (o).

Subpart X—[Amended]

32. 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 onsite production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment offsite.

* * * * *

(g) A process that solely distills or recycles waste solvent that contains a petrochemical is not part of the petrochemical production source category.

33. 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.

* * * * *

34. Section 98.243 is amended by:

- a. Revising the second sentence of paragraph (b).
- b. Revising the definition of “MVC” in Equation X–1 in paragraph (c)(5)(i).
- c. 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) * * *

(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 each combustion unit that burns 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).

35. Section 98.244 is amended by revising paragraphs (b)(1) through (b)(3) and (b)(4) introductory text; and by adding paragraphs (b)(4)(xi) through (b)(4)(xiii) 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 biennially (*i.e.*, once every two years) or at the minimum frequency specified by the manufacturer.

(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 according to one of the following. You may use either an industry consensus standard method or methods specified by the flow meter manufacturer. 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). You must recalibrate each flow meter according to one of the following frequencies. You may recalibrate either biennially, at the minimum frequency specified by the manufacturer, 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 (*e.g.*, ASTM, API, etc.) or you may use industry standard practice.

(4) Use any applicable methods specified in paragraphs (b)(4)(i) through (b)(4)(xiii) 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)(xiii), 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)(xiii) of this section may be performed by the owner or operator, by an independent laboratory, or by the supplier of a feedstock.

* * * * *

(xi) ASTM D2593-93 (Reapproved 2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, (incorporated by reference, *see* § 98.7), effective as of January 1, 2010.

(xii) An industry standard practice for carbon black feedstock oils and carbon black products, effective as of January 1, 2010.

(xiii) Modifications of existing analytical methods or other analytical methods that are applicable to your process provided that the methods listed in § 98.244(b)(4)(i) through § 98.244(b)(4)(xii) 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, effective as of January 1, 2010.

36. 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 for gaseous feedstocks and products used in Equation X-1 of this subpart, and the temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X-1 of this subpart were determined. Indicate whether you used the alternative to sampling and analysis specified in § 98.243(c)(4).

* * * * *

(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)(xiii), report the information listed in paragraphs (a)(11)(i) through (a)(11)(iii) of this section. Include the information in paragraph (a)(11)(i) of this section in each annual report. Include the information in paragraphs (a)(11)(ii) and (a)(11)(iii) of this section only in the first applicable annual report, and provide any changes to this information in subsequent annual reports.

(i) Name or title of the analytical method.

(ii) A copy of the method. If the method is a modification of a method listed in § 98.244(b)(4)(i) through (xii), 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 (xii) 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).

37. 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]

38. 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. * * *

39. Section 98.253 is amended by:

a. Revising paragraph (b)(1)(ii)(A).

b. Revising the definition of "MVC" in Equation Y-3 in paragraph (b)(1)(iii)(C).

- c. Revising paragraph (c)(1)(ii).
- d. Revising the definition of "MVC" in Equation Y-6 in paragraph (c)(2)(i).
- e. Revising paragraph (c)(2)(ii).
- f. Revising the definition of "CB_Q" and "n" in Equation Y-11 in paragraph (e)(3).
- g. Revising the first sentence of paragraph (f) introductory text and the last sentence of paragraph (f)(1).
- h. Revising the definition of "MVC" in Equation Y-12 in paragraph (f)(4).
- i. Revising the definition of "M_{dust}" in Equation Y-13 in paragraph (g)(2).
- j. Revising paragraphs (h) introductory text and (h)(2).

- k. In paragraph (i)(1), revising the first two sentences and the definition of "MVC" in Equation Y-18.
- l. In paragraph (j), revising both sentences; and revising the definitions of "(VR)_p," "(MF_x)_p," and "MVC" in Equation Y-19.
- m. In paragraph (k), revising the first sentence and the definition of "MVC" in Equation Y-20.
- n. Revising paragraph (m) introductory text.
- o. Revising the definitions of "MF_{CH4}" and "MVC" in Equation Y-23 in paragraph (m)(2).
- p. 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:
 CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
 0.98 = Assumed combustion efficiency of a flare.
 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
 n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
 p = Measurement period index.

44 = Molecular weight of CO₂ (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).
 (Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "(MW)_p/MVC" with "1".
 (MW)_p = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement

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

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

Where:
 CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
 n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
 p = Measurement period index.
 (Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, you must determine the average molecular weight of the flare gas during the measurement period and convert the mass flow to a volumetric flow.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
 (%CO₂)_p = Mole percent CO₂ concentration in the flare gas stream during the measurement period (mole percent = percent by volume).

y = Number of carbon-containing compounds other than CO₂ in the flare gas stream.
 x = Index for carbon-containing compounds other than CO₂.
 0.98 = Assumed combustion efficiency of a flare (mole CO₂ per mole carbon).
 (%C_x)_p = Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)
 CMN_x = Carbon mole number of compound "x" in the flare gas stream (mole carbon atoms per mole compound). E.g., CMN for ethane (C₂H₆) is 2; CMN for propane (C₃H₈) is 3.
 * * * * *
 (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 CO₂ emissions (e.g., co-mingled with emissions from a CO boiler) you must also calculate the other CO₂ 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 CO₂ 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).

* * * * *

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:

CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).
 0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).
 CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data

(metric tons C/MMbbl asphalt blown); default = 2,750.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).

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

Where:

CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).
 Q_{AB} = Quantity of asphalt blown (MMbbl/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
 EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default = 1,100.

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).

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

Where:

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

section that can be reasonably expected to contain greater than 2 percent by volume CO₂ or greater than 0.5 percent by volume of CH₄ or greater than 0.01 percent by volume (100 parts per million) of N₂O, calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section to calculate CH₄ emissions for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.

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 CH₄ emissions using the applicable methods in paragraphs (m)(1) through (m)(3) of this section.
 (2) * * *

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

* * * * *
 (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.

MF_{CH₄} = Average mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tanks from facility measurements (kg-mole CH₄/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).
 * * * * *

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).
 * * * * *

* * * * *
 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 CH₄ emissions from loading operations using vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

(j) For each process vent not covered in paragraphs (a) through (i) of this

(k) For uncontrolled blowdown systems, you must calculate CH₄ emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH₄ concentration or using Equation Y20 of this section. * * *
 * * * * *

40. Section 98.254 is amended by:
 a. Revising paragraph (a).

- b. Revising paragraph (b).
- c. Revising paragraph (c).
- d. Revising paragraphs (d) introductory text and (d)(6).
- e. Adding a new 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 CO₂ 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 in the applicable methods specified in paragraphs (c) through (g) of this section or the procedures specified by the manufacturer. In the case of gas flow meters, all gas flow meters must meet the calibration accuracy requirements in § 98.3(i). You must recalibrate each gas flow meter according to one of the following frequencies. You may recalibrate either biennially (every two years), at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used. You must recalibrate each gas composition monitor and heating value monitor according to one of the following frequencies. You may recalibrate either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(c) For flare or sour gas flow meters, operate, calibrate, and maintain the flow meter according to one of the following. You may use a method published by a consensus-based standards organization or the procedures specified by the flow meter manufacturer. Consensus-based standards include, but are not limited to, the following: ASTM International, the American Society of Mechanical Engineers (ASME), and the American Gas Association (AGA).

(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) or § 98.253(j), 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 or the procedures specified by the manufacturer. * * *

* * * * *

41. 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 a new 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 a new paragraph (f)(9).

h. Revising newly designated paragraphs (f)(11) through (f)(13).

i. Revising paragraphs (g)(5), (h)(2), (h)(4), and (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 a new paragraph (j)(8).

n. Revising paragraphs (k)(1), (k)(3), (l) introductory text, (l)(5), and (m).

o. Revising paragraph (o).

§ 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) and the annual average higher heating value of the flare gas (in MMBtu per MMscf).

(9) If you use Equation Y–3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during

normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf), the number of SSM events exceeding 500,000 scf/day, the volume of gas flared (in scf/event), the average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.

* * * * *

(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 (Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or Equation Y-22 of this section, other).

(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.

* * * * *

42. 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]

43. Section 98.273 is amended by:

- a. Revising paragraphs (a)(1) and (a)(2).
- b. Revising paragraphs (b)(1) and (b)(2).
- c. 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).

* * * * *

(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.

* * * * *

44. Section 98.276 is amended by revising the introductory text 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:

* * * * *

45. In the Tables to Subpart AA of Part 98, Table AA-2 is revised to read as follows:

TABLE AA-2 OF 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		0.0001
Biogas				0.0001
Petroleum coke			NA	^a NA

^aEmission factors for kraft calciners are not available.

Subpart OO—[Amended]

46. 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).

* * * * *

47. Section 98.414 is amended by:
- a. Adding a second and third sentence 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 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 destroyed.

* * * * *

(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 October 12, 2010 if the fluorinated GHG product is being produced on August 11, 2010. Perform the measurements within 60 days of commencing production of any fluorinated GHG product that was not being produced on August 11, 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.

48. Section 98.416 is amended by:

- a. Revising paragraph (a)(3).
- b. Removing and reserving paragraph (a)(4).
- c. Revising paragraph (a)(11).
- d. Revising paragraphs (c) introductory text and (c)(1).
- e. Revising paragraph (d) introductory text.
- f. 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.

* * * * *

(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.

* * * * *

(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:

* * * * *

(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.

49. Section 98.417 is amended by revising paragraph (a)(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 industry standards or manufacturer directions used for calibration pursuant to § 98.414(m) and (o).

* * * * *

(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.

50. 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]

51. 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.

52. Section 98.423 is amended by:

- a. Revising the first sentence of paragraph (a) introductory text.
- b. Revising the first sentence of paragraphs (a)(1) and (a)(2).
- c. Redesignating paragraph (b) as paragraph (c) and revising the only sentence in newly designated paragraph (c).
- d. Adding a new 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. * * *

(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,u} = Quarterly CO₂ concentration measurement of CO₂ stream u that delivers CO₂ to containers in quarter p (vol. %CO₂).

Q_p = Quarterly volume of contents supplied in all containers delivered by CO₂ stream u in quarter p (metric tons) (standard cubic meters).

D_p = Quarterly CO₂ stream density determination for CO₂ stream u in quarter p (metric tons per standard cubic meter).

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-3 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.

53. Section 98.424 is amended by revising paragraphs (a)(1), (a)(2), (a)(5)introductory text, (a)(5)(ii), the last sentence in paragraph (b)(2); and by adding paragraph (c) to read as follows:

§ 98.424 Monitoring and QA/QC requirements.

(a) * * *

(1) Reporters following the procedures in paragraph (a) of § 98.423 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 after the point of segregation.

(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 delivered, sum the mass of contents supplied in all containers to which the CO₂ stream 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 delivered, sum the volume of contents supplied in all containers to which the CO₂ stream 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 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:

* * * * *

(ii) You shall follow industry standard practices.

(b) * * *

(2) * * * Acceptable methods include 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 (incorporated by reference, see § 98.7 of subpart A of this part).

(c) If you measure the flow of the CO₂ stream with a volumetric flow meter, you shall convert 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 must use 0.0018704 metric tons per standard cubic meter.

54. Section 98.425 is amended by adding a new paragraph (d) to read as follows:

§ 98.425 Procedures for estimating missing data.

* * * * *

(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.

55. Section 98.426 is amended by:

- a. Revising paragraphs (a) introductory text and (a)(2).
- b. Adding a new paragraph (a)(5).
- c. Revising paragraphs (b) introductory text and (b)(2).
- d. Adding a new 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.

* * * * *

(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) If you use Equation PP-3 of this subpart report the annual CO₂ mass in metric tons from all flow meters and CO₂ streams that delivers CO₂ to containers.

* * * * *

(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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