

and solid hydrocarbon fuels of commerce to be characterized upon delivery if delivered by bulk transport (e.g., by truck or rail). Other non-standard gaseous fuels and feedstocks must still be subjected to weekly sampling and analysis to determine the carbon content and molecular weight.

*Comment:* Commenters recommended that EPA limit the requirement for sampling non-gaseous fuels to new deliveries rather than monthly in order to pinpoint the onset of fuel parameter variations.

*Response:* EPA concurs that the carbon content of a liquid or solid hydrocarbon fuel delivered in bulk will remain constant as the stock on hand from the delivery is consumed, and therefore periodic testing during the interim is not needed. EPA has revised this section to allow the characterization of feedstocks to be conducted by either the consumer or the supplier, to allow standard gaseous hydrocarbon fuels of commerce to be characterized annually, and allow liquid and solid hydrocarbon fuels of commerce to be characterized upon delivery if delivered by bulk transport (e.g., by truck or rail). On the other hand, other non-standard gaseous fuels and feedstocks must still be subjected to weekly sampling and analysis to determine the carbon content and molecular weight since their carbon content can vary significantly from week to week.

*Comment:* Multiple commenters recommended that EPA should include provisions for an extension of the required meter/monitor calibration deadline (as well as the initial calibration, if appropriate) when the calibration would require removing the process line from service. They recommend that the calibration requirement be extended to the next scheduled maintenance shutdown for the impacted unit/process.

*Response:* EPA concurs that requiring the facility to remove the process line from service represents an undue hardship and has therefore revised 40 CFR part 98, subpart P to refer to the less stringent monitoring and QA/QC requirements for the Tier 3 methodology included in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

*Comment:* One commenter suggested adding ISO 5167-1 through ISO 5167-4 (Measurement of Fluid Flow by Means of Pressure Differential Devices) to list of standards incorporated by reference.

*Response:* EPA agrees ISO 5167-1 through ISO 5167-4 are suitable calibration standards and would be good additions to the list of standards. However, given that the issues covered

by these standards (Venturi and orifice plate differential pressure flow meters) are covered by two American Society of Mechanical Engineers (ASME) standards, one ASHRAE standard, and one AGA report which are already included in 40 CFR 98.164, EPA has not explicitly added these references to the list of standards incorporated by reference.

#### Procedures for Missing Data

*Comment:* Multiple commenters recommended that the data substitution method for missing feedstock supply rate data should be changed to be consistent with 40 CFR 98.35(b)(2), allowing use of the "best available estimate", and that the data substitution method for missing feedstock carbon content data should be changed to be consistent with 40 CFR 98.35(b)(1), allowing use of the average before/after values.

*Response:* EPA concurs that the required level of accuracy for hydrogen production is similar to that required for stationary combustion, and that the less stringent "best available estimate" approach is appropriate for hydrogen production. Therefore, EPA has changed 40 CFR 98.165 to follow the data substitution method for missing fuel carbon content data prescribed in 40 CFR 98.35 and the data substitution method for missing fuel usage data prescribed in 40 CFR 98.35.

#### Data Reporting Requirements

*Comment:* Multiple commenters stated that annual feedstock consumption, annual hydrogen production, and feedstock carbon content are confidential business information (CBI) and should not be reported. The commenters asked that this information be maintained by the facility and be made available to the Agency upon request. One commenter further stated that if data must be reported, the reporting rules must provide explicit protection for this very critical confidential business information.

*Response:* Feedstock consumption and feedstock carbon content are parameters used to calculate emissions. Since annual CO<sub>2</sub> emissions are calculated from the sum of the products of monthly feedstock consumption multiplied by the monthly average carbon content of the feedstock, all of these parameters are required for emissions data verification purposes. Annual hydrogen production is an additional parameter which is necessary for EPA to effectively verify emissions, since the ratio of carbon emissions to hydrogen production is relatively

consistent for each hydrogen production facility. See Section II.N of this preamble for information on emissions verification. EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues."

#### Q. Iron and Steel Production

##### 1. Summary of the Final Rule

*Source Category Definition.* The iron and steel production source category consists of facilities with any of the following processes:

- Taconite iron ore processing.
- Integrated iron and steel manufacturing.
- Cokemaking not co-located with an integrated iron and steel manufacturing process.
- EAF steelmaking not co-located with an integrated iron and steel manufacturing process.

Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace for refining molten iron into steel. Each cokemaking process and EAF process located at a facility with an integrated iron and steel manufacturing process is part of the integrated iron and steel manufacturing facility.

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

*GHGs to Report.* Report the following emissions annually:

- CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion at each stationary combustion unit according to the requirements in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). Stationary combustion units include, but are not limited to, byproduct recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flame suppression, ladle reheaters, and any other miscellaneous combustion sources (except flares).
- CO<sub>2</sub> emissions from flares according to the requirements in 40 CFR part 98, subpart Y (Petroleum Refineries) and CH<sub>4</sub> and N<sub>2</sub>O emissions from flares using the default emission factors for coke oven gas and blast furnace gas.
- CO<sub>2</sub> process emissions from each taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven

battery combustion stack, coke pushing process, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace.

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

**GHG Emissions Calculation and Monitoring.** For CO<sub>2</sub> process emissions at each taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace, reporters must calculate emissions using one of the following methods, as appropriate:

- Most reporters can elect to calculate and report process CO<sub>2</sub> emissions by either: (1) Installing and operating a CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using one of the following two calculation procedures:

- Use a carbon balance method described in 40 CFR part 98, subpart Q to calculate the annual mass emissions rate of CO<sub>2</sub> for each process, based on the annual mass of inputs and outputs and an annual analysis of the respective weight fraction of carbon in each process input or output that contains carbon. Use separate procedures and equations for taconite indurating furnaces, basic oxygen process furnaces, nonrecovery coke oven batteries, sinter processes, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces, or
- Use a site-specific emission factor determined from a performance test that measures CO<sub>2</sub> emissions from all exhaust stacks and also measures either the feed rate of materials into the process or the production rate during the test for taconite indurating furnaces, basic oxygen process furnaces, nonrecovery coke oven batteries, sinter processes, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces.

- However, if process CO<sub>2</sub> emissions from a taconite indurating furnace, basic oxygen furnace, nonrecovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace are emitted through the same stack as CO<sub>2</sub> emissions from a combustion unit or process equipment that uses a CEMS and follows the Tier 4 methodology to report CO<sub>2</sub> emissions, then the CEMS must be used to measure and report combined CO<sub>2</sub> emissions from that stack. In such cases, the reporter cannot

use the other process CO<sub>2</sub> calculation approaches outlined above.

- For coke oven pushing, facilities must use a CO<sub>2</sub> emission factor provided in the rule.

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

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

## 2. Summary of Major Changes Since Proposal

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

The major changes made since proposal include:

- The carbon mass balance method was revised to require an annual analysis of all process inputs and outputs for carbon content rather than weekly sampling and monthly analysis.
- The site-specific emission factor method was revised to: (1) Require testing based on representative performance rather than at 90 percent of capacity, (2) sampling for a minimum of three hours or production cycles rather than nine, (3) conducting separate tests for each different process condition that is a part of normal operation if the change in CO<sub>2</sub> emissions at the different conditions is more than 20 percent, and (4) adding a provision to clarify testing requirements when the EAF and argon-oxygen decarburization vessel are ducted to the same control device and stack.
- To improve the emissions verification process, 40 CFR 98.176 was reorganized and updated. Some data elements were moved from 40 CFR 98.177 to 40 CFR 98.176, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.173 were added to 40 CFR 98.176 for clarity.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses related to the requirements for iron and steel processes. A large number of comments on iron and steel production were received covering numerous topics. Many of these comments were directed at the requirements for 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and responses to those comments are provided in Section III.C of this preamble. *Also see* the Section II.N of this preamble for the response to comments on the emissions verification approach. Responses to other significant comments received related to process emissions from iron and steel production can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart Q: Iron and Steel Production.”

### Method for Calculating GHG Emissions

**Comment:** Several industry representatives and their three trade associations requested that EPA allow the use of a simplified facility-wide carbon balance approach developed by the American Iron and Steel Institute (AISI) to calculate CO<sub>2</sub> emissions from iron and steel production facilities. According to the commenters, the AISI methodology has recently been adapted to facility-wide reporting and is emerging as the preferred reporting protocol internationally. The commenters described the approach as based on determining the mass of carbon in the most significant carbon-containing inputs entering the plant and in the most significant carbon-containing outputs that leave as products or byproducts (excluding, for example, iron ore, scrap, steel). The difference between the mass of carbon entering the facility and leaving the facility is assumed to be converted to CO<sub>2</sub>. The annual mass rates of significant inputs and outputs are determined from company records, and their carbon contents are based on typical or default values. The commenters noted that the AISI approach provides a single estimate of the combined total CO<sub>2</sub> emissions from all processes and combustion sources at the facility. The commenters claimed that the approach would provide a more accurate and complete accounting of facility-wide emissions at a much lower cost than that of the proposed EPA process-specific methods.

**Response:** As we explained at proposal (74 FR 16517), we considered the many domestic and international

monitoring guidelines and protocols for process and combustion sources at iron and steel production facilities, including the AISI facility-wide approach. The vast majority of these guidelines and protocols are process-specific rather than facility-wide approaches (e.g., 2006 IPCC Guidelines, U.S. Inventory, the World Business Council for Sustainable Development (WBCSD)/WRI GHG protocol, DOE 1605(b), TCR, European Union Emissions Trading System, and Environment Canada's mandatory reporting guidelines). In addition, the "higher tier" (more accurate) site-specific methods use process-specific approaches. We explained at proposal (74 FR 16517) that we did not choose to propose these approaches based on the use of default values in general (such as the AISI approach) because the use of default values and lack of direct measurements results in a very high level of uncertainty (greater than  $\pm 25$  percent), and default approaches would not provide site-specific estimates of emissions that reflect differences in feedstocks, operating conditions, fuel combustion efficiency, variability in fuels, and other differences among facilities.

We also stated at proposal that we decided not to finalize the proposal using methodologies that relied on default emission factors or default values for carbon content of materials because the differences among facilities described above could not be discerned, such default approaches are inherently inaccurate for site-specific determinations, and the use of default values is more appropriate for sector wide or national total estimates from aggregated activity data than for determining emissions from a specific facility.

We further note here that the AISI approach is not adequate for our reporting needs because it provides only a single emissions number aggregated from the numerous individual processes and combustion units at the iron and steel facility. In contrast, the approaches we are promulgating today for determining CO<sub>2</sub> emissions provide information at the process level and distinguish between combustion emissions and process emissions. Information at the process level is needed for many reasons, such as verification of the reported emissions from comparison with known ranges expected from various types of processes for a given production rate and emissions verification based on data for different plants for similar processes. Process-level reporting also provides information that will be useful in

identifying processes that have reduced emissions over time and processes at specific plants that have the most potential for future reductions in emissions. In addition, the process-level reporting may provide information that can be used to improve methodologies for specific processes under future programs and to identify processes that may use a technology that could be the basis for an emission standard at a later time.

We developed estimates of costs for the proposed options for determining CO<sub>2</sub> emissions and concluded that the costs were reasonable. However, as explained below, we have revised the proposed options in response to comments, and these revisions significantly reduce the burden and costs of the carbon mass balance and site-specific emission factor methods while maintaining a similar level of accuracy.

*Comment:* Several commenters claimed that the proposed carbon mass balance method is unnecessarily burdensome because it requires weekly sampling, monthly analyses, and determining the monthly mass quantities of all process inputs and outputs. The commenters suggested that EPA allow the use of default values for carbon content, neglect streams that have very little or no carbon, drop the requirement for analysis by an "independent certified laboratory," and allow the use of analyses from suppliers. One commenter recommended sampling and analysis for carbon content no more frequently than annually. The commenters stated that lime, dolomite and slag contain no appreciable carbon and do not need to be tracked, and that it is not necessary to account for the carbon in scrap that is charged to the furnace or in the steel product because they offset each other. One commenter noted that "independent certified laboratory" is not defined or explained, and another claimed that it is an unnecessary complication and expense because these carbon analyses are typically done in an in-house laboratory.

One commenter stated that the carbon mass balance equations were incomplete because they did not account for carbon removed by pollution control devices. Another commenter recommended that EPA use default carbon contents for different grades of steel scrap and noted that because companies already track the chemical content of each grade of scrap, highly accurate carbon calculations could be made with minimal additional burden.

*Response:* We received several useful suggestions for improving the carbon mass balance method without significantly decreasing the accuracy in the estimates. After a close review of the sampling and analysis requirements and comparing them to the requirements applied to other source categories in other subparts of this reporting rule, we concluded that the weekly sampling and monthly analysis of carbon content could be reduced in frequency to an annual analysis of all inputs and outputs at each facility. We also revised the rule to allow the use of carbon content analyses from the material supplier, which is consistent with what is required in other subparts using the carbon balance method. Carbon content does not vary widely at a given facility for the significant process inputs and outputs that contain carbon, and we continue to account for variations due to changes in production rate, which is likely a more significant source of variability. We continue to choose not to use default values for the reasons given in the previous comment response, and we have determined that an annual analysis of carbon content to provide plant-specific values is not burdensome because facilities already perform many such analyses. We agree that the analysis does not have to be performed by an independent certified laboratory, especially since we specify the analytical procedures that must be used by any laboratory, and we note that in-house laboratories may have more applicable experience in analyses of their particular process inputs and outputs.

We agree with the suggestion to evaluate carbon content by the grade or type of ferrous material charged to the furnace, and we incorporated a provision to calculate an average carbon content of ferrous materials charged based on the average weight percent of each type that is used. In addition, we have corrected the equations as suggested to account for carbon in the residue collected by emission control equipment. Finally, we agree that inputs and outputs that contain no carbon or an insignificant amount (i.e., contributing to less than one percent of the carbon in or out) do not need to be tracked in the carbon balance method.

*Comment:* Several commenters claimed that the site-specific emission factor method is not a viable option as proposed and should be streamlined to: (1) Eliminate annual re-testing, (2) reduce the test length from nine hours (or from nine production cycles for batch processes), (3) clarify that a separate test is not required for each grade of steel, and (4) remove the

requirement to operate at 90 percent of capacity. One commenter stated that the most frequent re-testing currently required in operating permits is once every 2.5 years rather than annually. Another commenter noted that nine production cycles for certain small specialty steel producers would require 27 hours of testing for each grade of steel because each production cycle is three hours. Commenters stated that testing at 90 percent of production is problematic and is beyond their control because it is dictated by upstream and downstream production levels as well as economic conditions. In addition, capacity is difficult to determine because steelmaking furnaces do not have a nameplate capacity since it is determined by the iron production rate, how fast downstream processes (such as the caster) operate, process inputs, and product specifications that may require different operating cycle times.

One commenter questioned the value of the requirement to re-test if the carbon content of feed materials changes by more than 10 percent because this type of change could occur on a daily or weekly basis when the grade of steel being produced changes. Another commenter noted that EPA did not define what constituted a significant change in fuel type or mix and recommended that the provision be changed to 20 percent to allow for environmentally beneficial process improvements. Two commenters stated that the 10 percent threshold for re-testing is infeasible for steelmaking and sinter processes because of routine changes in the type of steel produced and the types of materials recycled to the sinter plant. The commenters requested that they be permitted to develop separate emission factors based on various modes that represent different operating scenarios or product categories. The commenters also recommended that EPA eliminate the 10 percent change threshold for re-testing and require that testing be conducted under conditions that are representative of normal operation. One commenter noted that the rule did not address how a site-specific emission factor would be developed when emissions from the EAF and argon-oxygen decarburization vessel are combined and routed to a single emission control device and stack.

*Response:* We further reviewed the testing requirement in other rules and those in operating permits and found that typical requirements (such as test requirements for particulate matter) include 3 one-hour runs or production cycles for representative testing of process emissions. Consequently, we are

revising the testing requirements to three hours or three production cycles. We also agree with the commenters who noted that different routine operating modes may result in different levels of CO<sub>2</sub> emissions, and it is necessary to develop separate emission factors for these different operating conditions. Consequently, we have dropped the 10 percent re-testing threshold and instead require that separate emission factors be developed for each of different routine operating conditions that result in a change in CO<sub>2</sub> emissions by 20 percent or more.

We disagree that annual re-testing is excessive because testing for CO<sub>2</sub> emissions is much simpler and less costly than sampling for hazardous pollutants or for particulate matter, and annual sampling is consistent with our requirement for annual reporting. We agree that it is not necessary or always possible to test while operating at 90 percent of capacity for the reasons identified by the commenters. Instead, we are requiring that the test be performed based on representative performance, i.e., under normal operating conditions. We have revised the rule to clarify and provide options for testing when emissions from the EAF and argon-oxygen decarburization vessel are combined.

*Comment:* Several commenters asked EPA to clarify that CH<sub>4</sub> and N<sub>2</sub>O emissions do not have to be reported for iron and steel production processes, and other commenters requested that CH<sub>4</sub> and N<sub>2</sub>O emissions reporting not be required for the combustion of coke oven gas and blast furnace gas. Commenters noted that default emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O were not provided in the tables in 40 CFR part 98, subpart C, and in the absence of such emission factors, asked if they would be required to test for these minor emissions.

*Response:* We have clarified that 40 CFR part 98, subpart Q does not require reporting of CH<sub>4</sub> and N<sub>2</sub>O emissions from the iron and steel production processes because we expect these emissions (if any) to be very low, and we have no protocols for calculating them. However, emission factors are available in the 2006 IPCC guidelines for combustion sources, including the combustion of coke oven gas and blast furnace gas. We have added the IPCC default emission factors for CO<sub>2</sub> and N<sub>2</sub>O for these process gases to the tables in 40 CFR part 98, subpart C, and we developed new emission factors for CH<sub>4</sub> based on the typical CH<sub>4</sub> content of coke oven gas (28 percent) and blast furnace gas (0.2 percent).

## R. Lead Production

### 1. Summary of the Final Rule

*Source Category Definition.* The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques (smelting). A secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

Reporters must submit annual GHG reports for primary lead smelters and secondary lead smelters that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

*GHGs to Report.* For lead production, report the following emissions:

- CO<sub>2</sub> process emissions from each smelting furnace used for lead production.
  - CO<sub>2</sub> combustion emissions from each smelting furnace used for lead production.
  - N<sub>2</sub>O and CH<sub>4</sub> emissions from each smelting furnace under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
  - CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each on-site stationary combustion unit other than smelting furnaces under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

*GHG Emissions Calculation and Monitoring.* To calculate annual process CO<sub>2</sub> emissions from an affected smelting furnace, the reporter must use the following methods, as applicable to the affected smelting furnace.

- For each affected smelting furnace with certain types of CEMS in place, the reporter must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the Lead Production subpart (40 CFR part 98, subpart R) combined process and combustion CO<sub>2</sub> emissions.
- For other affected smelting furnaces, the reporter can elect to either (1) install and operate a CEMS and follow the Tier 4 methodology to measure and report combined process and combustion CO<sub>2</sub> emissions or (2) calculate annual process CO<sub>2</sub> emissions using a carbon mass balance procedure specified in 40 CFR part 98, subpart R. If using approach (2):

- Calculate emissions once per year using recorded monthly production data and the average carbon content for each smelting furnace input material determined by either using material supplier information or by annual analysis of representative samples of the material.
- Report process CO<sub>2</sub> emissions from each smelting furnace under 40 CFR part 98, subpart H (Cement Production), and report combustion CO<sub>2</sub> emissions from each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

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

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

## 2. Summary of Major Changes Since Proposal

The major changes to the rule since proposal for lead production facilities were revisions to the carbon mass balance calculation procedure used by reporters for calculating process CO<sub>2</sub> emissions from affected smelting furnaces. The rationale for these and any other significant changes can be found below or in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart R: Lead Production.”

- The frequency of performing the carbon mass balance calculations was revised to be required on an annual basis instead of the proposed monthly basis.
- The frequency of material carbon content sampling and analysis of each smelting furnace input material used for the carbon mass balance was revised to be performed by annual analysis of representative samples of the material instead of the proposed monthly basis.
- A *de minimis* carbon content level was added to exclude the need to account for carbon-containing materials contributing less than one percent of the total carbon into the smelting furnace in the carbon mass balance calculations.

- Data reporting procedures (40 CFR 98.186) were reorganized and updated to consolidate and clarify the emissions verification process. Some data elements for the carbon mass balance calculation were moved from 40 CFR 98.187 to 40 CFR 98.186, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.183 were added to 40 CFR 98.186 for clarity.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses specific to the lead production source category. Comments were received from one commenter regarding several topics. Responses to significant comments received are presented in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart R: Lead Production.”

### Selection of Threshold

**Comment:** The commenter stated that Lead Production is not a source of significant GHG emissions and that EPA cannot assert that the Lead Production sector is a significant part of the stationary source combustion sector. The commenter notes that based on EPA’s estimates in the TSDs for the proposal, estimated emissions from the Lead Production sector are 0.02 percent of the total estimated nationwide emissions from stationary fossil fuel combustion. Moreover, they argue that the combustion-related emissions from lead production are overstated by incorrect assumptions in the TSD. The commenter states that given Lead Production’s relative contribution, it is not a significant source of emissions and should be eliminated from further consideration. The commenter further states that Lead Production is the only category evaluated where raising the threshold to the 100,000 ton level would result in zero facilities being covered. Accordingly, when the analysis shows that all facilities in a particular source category are not covered at the 100,000 ton threshold level, no insignificant GHG emitters in the category should be required to report under the Proposed Rule. The commenter noted that using the 100,000 threshold would not significantly reduce the coverage of emissions of EPA’s rule, as the majority of sources identified would still have well over 90 percent of emissions from that source category covered under the 100,000 threshold. EPA provides no justification for imposing substantially more costs on industry for limited estimated benefits and small likelihood for regulation under the CAA. For these

reasons, the Lead Production sector should be eliminated as a source category, and EPA should raise the threshold to 100,000 for non-source category facilities.

**Response:** We acknowledge this comment and concerns; however, the final rule retains the applicability requirement for this source category. We used information available to us for estimating GHG emissions from this industry which involved several assumptions related to the emission factors in the IPCC Guidance and other sources. As noted by the commenter, many of the underlying assumptions were based on an international perspective as opposed to the primary and secondary lead production industry in the U.S. The final rule contains a threshold of 25,000 metric tons CO<sub>2e</sub> and only lead production facilities with emissions that equal or exceed 25,000 metric tons CO<sub>2e</sub> will have to report emissions. In addition, the final rule now contains provisions allowing a reporter to cease reporting if the annual reports for a given facility demonstrate emissions less than specified levels for multiple years. These provisions apply to all reporting facilities, including those with lead production processes. See Section II.H of this preamble for the response on provisions to cease reporting.

We have further simplified the reporting requirement to further reduce burden for lead and similar industries by requiring annual as opposed to monthly sampling of carbon inputs. The purpose of this rule is to collect information on emissions sources for future policy development. Requiring reporting for these sources will provide EPA with valuable data to better characterize them and provide a more credible position if EPA elects to exclude these sources from future GHG policy analyses. Additionally, while some of these sources are currently believed to be small compared to the larger sources, they are not necessarily insignificant. The inclusion of reporting data for these sources is critical to support analysis of future policy decisions for lead production facilities.

When evaluating potential thresholds for reporting GHG emissions, we considered several thresholds between 1,000 and 100,000 metric tons CO<sub>2e</sub>. We selected the 25,000 metric tons CO<sub>2e</sub> threshold for reporting GHG emissions in order to achieve a balance between quantifying the majority of the emissions, while minimizing the number of facilities impacted. For example, at a 1,000 metric tons CO<sub>2e</sub> threshold, 99 percent of emissions would be covered, with about 63

percent of facilities being required to report. The 100,000 metric tons CO<sub>2</sub>e threshold captures no emissions or facilities while the proposed 25,000 metric tons CO<sub>2</sub>e threshold achieves reporting of 92 percent of the GHG emissions while requiring less than 50 percent of the facilities to report. We consider this a significant coverage of the emissions, while impacting a relatively small portion of the industry. We believe the proposed threshold of 25,000 metric tons CO<sub>2</sub>e represents the best option for ensuring that the majority of emissions are reported without imposing an unreasonable burden on the industry. See also Section II.E of this preamble and “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.”

#### Method for Calculating GHG Emissions

*Comment:* The commenter made several comments regarding the proposed procedures used to calculate process CO<sub>2</sub> emissions from smelting furnaces at secondary lead smelters. First, use of default emission factors should be allowed as a calculation method alternative because the smelting furnaces operated at used lead battery recycling facilities consistently process furnace feed materials with low carbon content variability. For affected sources using the carbon mass balance procedure, the frequency required for monitoring carbon content of the smelting furnace input materials should be reduced to reflect consistency and low carbon content variability of these materials.

*Response:* We decided not to finalize the proposal using methodologies for calculating CO<sub>2</sub> emissions from lead production that relied on published default emission factors or default values for carbon content of materials because the differences among individual lead production facilities could not be discerned using these factors. Consequently, the available default factors for lead production facilities are inherently less accurate for calculating smelting furnace process CO<sub>2</sub> emissions than using procedures that include use of site-specific material carbon data. Default approaches do not provide site-specific estimates of emissions that reflect differences in use of and variability in feedstocks, variability in fuels, operating conditions, fuel combustion efficiency, and other differences among facilities. For some carbon-containing input materials, such as lead scrap, representative published defaults do not

exist. Therefore, the use of default values is more appropriate for sector wide or national total estimates from aggregated production data for multiple facilities rather than for providing an accurate representation of CO<sub>2</sub> emissions from a specific facility.

For the final rule, we did reduce the monitoring frequency for determining carbon contents of the smelting furnace input materials used for the carbon mass balance to be determined on annual rather than monthly basis. Facilities can determine carbon contents either by using material supplier information or by annual analysis of representative samples of the input materials. We agree that the carbon content for the significant input materials typically does not vary widely at a given lead production facility. Annual carbon content determinations will still provide representative carbon content data for the smelting furnace process CO<sub>2</sub> emissions calculations while minimizing the monitoring burden on reporters. We continue to account for process variations due to changes in production rate, which is likely a more significant source of variability in the CO<sub>2</sub> emissions from an affected smelting furnace during the year, by maintaining the requirement to measure and record monthly carbon containing input materials.

#### S. Lime Manufacturing

##### 1. Summary of the Final Rule

*Source Category Definition.* Lime manufacturing plants (LMPs) engage in the manufacture of a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) by calcination of limestone, dolomite, shells or other calcareous substances. This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes.

Lime kilns at pulp and paper manufacturing facilities need to report emissions under 40 CFR part 98, subpart AA (Pulp and Paper Manufacturing).

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble and meet the definition of lime manufacturing plants in 40 CFR 63.7081(a)(1).

*GHGs to Report.* For lime manufacturing, report the following emissions:

- Total CO<sub>2</sub> process emissions from all lime kilns combined.
- CO<sub>2</sub> combustion emissions from lime kilns.
- N<sub>2</sub>O and CH<sub>4</sub> emissions from fuel combustion at each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
- CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit other than kilns under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- CO<sub>2</sub> collected and transferred off site under 40 CFR part 98, subpart PP (Suppliers of CO<sub>2</sub>).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

*GHG Emissions Calculation and Monitoring.* For CO<sub>2</sub> emissions from kilns, facilities must use one of two methods, as appropriate:

- If all lime kilns at a facility have certain types of CEMS in place, the reporter must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to measure and report under the Lime Manufacturing subpart (40 CFR part 98, subpart S) combined process and combustion CO<sub>2</sub> emissions.
- If CEMS meeting the specifications above are not in place for all kilns at the facility, the reporter can elect to either (1) install and operate a CEMS and follow the Tier 4 methodology to measure and report combined process and combustion CO<sub>2</sub> emissions from all lime kilns or (2) calculate CO<sub>2</sub> process emissions for each lime type using an emission factor for each lime type, the mass of lime produced, an emission factor for byproduct/waste (such as lime kiln dust and scrubber sludge), and the mass of byproduct/waste. If using approach (2):

- Each emission factor must be determined monthly for each lime type from monthly measurements of the calcium oxide and magnesium oxide content of the lime and stoichiometric ratios of CO<sub>2</sub> to each oxide in the lime.
- The emission factor for each lime byproduct/waste sold (such as lime kiln dust) must be determined monthly.
- The emissions from lime byproducts/wastes that are not sold (such as lime kiln dust and scrubber sludge) must be determined annually.
- The mass of each lime type produced and lime byproduct/waste sold (such as lime kiln dust) must be recorded on a monthly basis.

- The mass of each lime byproduct/waste not sold (such as lime kiln dust and scrubber sludge) must be recorded annually.
- Report process CO<sub>2</sub> emissions from all kilns combined under 40 CFR part 98, subpart S (Lime Manufacturing), and report combustion CO<sub>2</sub> emissions from each kiln under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

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

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

## 2. Summary of Major Changes Since Proposal

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

- The definition of lime manufacturing was revised to be similar to the definition in the Lime NESHAP at § 63.7081(a) and (a)(1).

- Reporting requirements were revised from a “per kiln” basis to “all kilns combined”.

- The emissions calculations were revised to determine monthly emissions factors for each lime type and byproduct/waste type rather than for each kiln.

- Emission calculations for byproducts/wastes were added.

- The requirement to measure the calcium oxide and magnesium oxide content of byproducts/wastes on a monthly basis was changed to an annual basis for byproducts/wastes that are not sold.

- The correction factor for byproducts/wastes was removed from the rule.

- Additional direct measurement devices/methods are being allowed to include those currently in use by the industry.

- 40 CFR 98.196 was reorganized and updated. Some data elements were moved from 40 CFR 98.197 to 40 CFR 98.196, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.193 were added to 40 CFR 98.196 for clarity.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on lime manufacturing were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart S: Lime Manufacturing.”

### Definition of Source Category

**Comment:** Multiple commenters requested more clarification in defining which sources and equipment are covered by the proposed rule. The rule defines the source category as a facility that contains “a rotary lime kiln to produce a lime product.” In addition, proposed 40 CFR 98.192(b) required sources to report emissions from “each lime kiln and any other stationary combustion unit.”

**Response:** We have reviewed the rule language and decided the source category definition should provide more clarity. The source category is meant to include all kiln types used in the lime manufacturing industry; therefore, language in the final rule has been changed to be similar to the definition from the Lime NESHAP in 40 CFR 63.7081(a) and (a)(1). This Lime NESHAP effectively characterizes lime plants as those engaging in the manufacture of a lime product by calcination. The final rule requires all stationary combustion units to report under 40 CFR part 98, subpart C of the final rule.

Final rule language under 40 CFR 98.192 requires facilities to report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from kilns used in the lime manufacturing process and all other combustion units at the lime manufacturing facility other than kilns. The language has also been clarified in 40 CFR 98.193. Facilities using CEMS for all lime kilns report combined process and combustion emissions from kilns under 40 CFR part 98, subpart S, according to the Tier 4 methodology in 40 CFR part 98 subpart C (General Stationary Fuel Combustion Sources). Facilities must follow the requirements of subpart C for estimating and reporting combustion related emissions for all other combustion units and report these emissions under subpart C. See Section

III.C of this preamble for an overview of the requirements for stationary combustion units.

### Selection of Proposed GHG Emissions Calculation and Monitoring Methods

**Comment:** Multiple commenters requested the language in 40 CFR part 98, subpart S be changed to allow emissions to be reported by “all kilns combined” instead of the proposed rule’s request to report emission for each kiln. Multiple commenters further recommended that the process emissions calculations be changed to calculate emissions by the lime type produced as opposed to the current rule calculations which use a kiln specific emission factor. Two commenters stated that lime products are commonly aggregated at the plant making it difficult to estimate the amount of product produced at an individual kiln. These commenters stated that current lime plant configuration do not allow accurate kiln specific calculations.

**Response:** We have reviewed the common lime plant configuration and the currently proposed rule language and have decided that it is not necessary to require kiln-specific emissions reporting. We have observed that some kilns would have to retrofit weigh belt scales in the production line between kilns and storage silos, since they do not currently exist. Calculating emissions by kiln could increase the reporting burden for these facilities. According to one commenter, when kiln-specific emissions have been reported in the past, the data are usually derived by distributing the aggregated emissions among the kilns. Accurate measurements at the kiln level are rarely achieved. If this is true for most lime manufacturing facilities, the data does not necessarily provide a better estimate of emissions.

For the purposes of this rulemaking, reporting for all kilns combined will simplify and minimize the reporting burden without significant loss in accuracy because: (1) Kilns may produce more than one type of lime in a given reporting period, (2) emission factors are based on lime type, and (3) lime plants collect products in combined bagging areas (separated by lime type). The final rule language has been changed to require reporting by lime type from all kilns combined rather than all lime types for each kiln. This final rule language is consistent with the National Lime Association (NLA) Protocol, which was used as the basis for the methodology in the proposed rule. Information collected under this rule will help to inform future methodologies and determine whether

kiln level reporting could be more appropriate for future reporting.

*Comment:* The proposed rule used a default correction factor in calculating lime product and byproduct/waste emissions. Multiple commenters suggested using the National Lime Association Protocol to determine lime product and by-product/waste process emissions. According to the commenters, this method is more precise due to the use of measured oxide values and stoichiometric ratios rather than correction factors.

*Response:* We have reviewed the proposed rule and NLA Protocol calculation methods and noted that the use of actual oxide measurements in calculating emissions from lime plants does not cause an additional burden to the reporter since this is a currently used practice. We also agree that the use of actual measurements is more accurate. Therefore, we have decided to remove the use of a correction factor in the final rule equations; emissions will be calculated from actual oxide measurements of each type of lime and calcined byproducts/wastes.

#### Monitoring and QA/QC Requirements

*Comment:* Multiple commenters asked that the language pertaining to allowable measurement devices for lime products and byproducts/wastes sold, be changed to include measurement devices commonly used in the lime industry. The current rule language requires weigh hoppers and belt weigh feeders as the measurement devices; the aforementioned commenters have identified bag, truck and rail scales as reliable (annually calibrated) direct measurement methods commonly used in the lime industry. In addition, commenters have requested lime byproducts/wastes not sold be calculated by a facility generation rate.

*Response:* After reviewing the rule language and common industry practices, we have decided to include other direct measurement devices used for accounting purposes, including but not limited to, weigh feeders, calibrated bag, rail or truck scales, and barge measurements. These methods are consistent with the original intent of the rule and add further clarification on measurement methods applicable to determine quantities of both lime produced and byproducts/waste generated.

In addition, reporters are required to perform an annual cross check by measuring lime products at the beginning and end of the year. For calcined byproducts/wastes not sold, a material balance approach that

indirectly measures the generation rate should be used.

*Comment:* Multiple commenters asked that the language in 40 CFR part 98, subpart S pertaining to testing the chemical composition of each type of lime (including the byproducts and waste) be changed to allow testing by onsite lab facilities. Currently the rule specifies an "off-site laboratory analysis" but according to the commenter, commercial lime plants normally have onsite lab facilities.

*Response:* We agree that the analysis does not have to be performed by an independent certified laboratory, especially since we specify the analytical procedures that must be used by any laboratory, and we note that in-house laboratories may have more applicable experience in determining chemical composition. Reporters can determine whether to perform the test onsite or send the samples to offsite laboratory facilities. Therefore the language in the final rule has been changed.

#### Data Reporting Requirements

*Comment:* Multiple commenters requested the language in 40 CFR part 98, subpart S pertaining to reporting information to EPA be changed so that business sensitive information is kept in company records. Commenters agree that the production capacity, product quality (i.e., oxide content), emission factors and operating hours and days for each kiln, are required for emissions calculations but are concerned that making this information public would give information about their efficiency, productivity and capacity of kilns and facility.

*Response:* EPA reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble for legal issues. Also, see Section II.N of this preamble for the response to comments on the emissions verification approach.

We agree that annual operating hours and capacities are not used in the calculation of CO<sub>2</sub> emissions and these parameters have been moved to recordkeeping. This information can help to verify anomalies in emissions data if there were temporary shutdowns, etc.

We disagree that emission factors and product quality be maintained as records rather than be reported. Emission factors and product quality are used in calculations to establish the site specific rate of CO<sub>2</sub> emissions generated for each type of lime produced. Therefore these data are required in order to verify the CO<sub>2</sub> emissions that

are being reported. This internal verification system ensures that the GHG emissions reported are accurate.

#### T. Magnesium Production

At this time EPA is not going final with the magnesium production subpart (40 CFR part 98, subpart T). For the immediate future, EPA believes that emissions of GHGs from magnesium production are sufficiently covered by the reporting requirements under 40 CFR part 98, subpart OO for Industrial Gas Supply. This information on U.S. production, imports, and exports of SF<sub>6</sub> will provide at least a general, order-of-magnitude check on consumption of SF<sub>6</sub> by magnesium production and other uses of SF<sub>6</sub>. EPA will finalize the proposed reporting requirements for the magnesium production industry at a later date.

#### U. Miscellaneous Uses of Carbonate

##### 1. Summary of the Final Rule

*Source Category Definition.* The Miscellaneous Uses of Carbonate source category consists of any facility that uses carbonates listed in Table U-1 of 40 CFR part 98, subpart U in manufacturing processes that emit carbon dioxide. The Table includes the following carbonates: Limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO<sub>2</sub> if they consume at least 2,000 tons per year of the carbonates listed above and that are heated to a temperature sufficient to allow calcination to occur.

This source category does not include facilities processing carbonates or carbonate containing minerals consumed for producing cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide or zinc as CO<sub>2</sub> emissions from these processes are covered elsewhere in this rule.

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

*GHGs to Report.* For miscellaneous uses of carbonates, report the following emissions:

- Annual CO<sub>2</sub> process emissions for all miscellaneous uses of carbonates as specified in this subpart.
- CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from carbonates used in sorbent technology and each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for other source categories at the facility for

which calculation methods are provided in the rule, as applicable.

**GHG Emissions Calculation and Monitoring.** Calculate process CO<sub>2</sub> emissions using annual carbonate consumption. All reporters must calculate the annual mass of carbonates used in processes which are heated to temperatures that allow calcination. If the annual amount of carbonates consumed is greater than 2,000 tons, CO<sub>2</sub> emissions must be calculated using either calcination fractions or the actual mass of input/output carbonates.

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

**Recordkeeping.** In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of analyses and calculations required for this source category.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart U: Miscellaneous Uses of Carbonates."

- The source category definition was revised to exclude non-emissive uses of carbonates.

- A *de minimis* reporting threshold was added to exclude facilities with minor emissions based on annual carbonate consumption.

- The GHG calculation methodology was changed to allow reporters to determine emissions from the mass of carbonate input/output or calcination fractions.

- To improve the emissions verification process, 40 CFR 98.216 was reorganized and updated. Some data elements were moved from 40 CFR 98.217 to 40 CFR 98.216, and some data elements that a reporter must already use to calculate GHG as specified in 40 CFR 98.213 were added to 40 CFR 98.216 for clarity.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on

miscellaneous uses of carbonates were received covering numerous topics. Most comments requested clarification on the definition of the source category and its applicability to affected sources. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart U: Miscellaneous Uses of Carbonates."

### Definition of Source Category

**Comment:** Multiple commenters requested that the source category be revised to exclude non-emissive uses of carbonates. Commenters stated that the source category is poorly defined, making it difficult to accurately assess its applicability to an industrial facility. Commenters noted a number of non-emissive uses as examples, such as the production of sodium bicarbonate and sodium hydroxide, during which sodium carbonates are used, but no carbon dioxide is released; onsite mixing of processed cement with aggregate, limestone used in poultry grit and as an asphalt filler; or adding sodium carbonate to a water softener system.

**Response:** The rule language has been modified to exclude non-emissive uses of carbonates. Non-emissive uses do not result in CO<sub>2</sub> emissions, such as adding sodium carbonate to a water softener system. Acid-induced releases of CO<sub>2</sub> from the use of carbonates are addressed in other subparts, where they are significant, such as Phosphoric Acid Production.

### Selection of Threshold

**Comment:** Multiple commenters requested that a *de minimus* reporting threshold be added to exclude facilities with minor emissions. One commenter noted that some facilities use limestone and other carbonate as refractory in furnaces, and it is unclear whether or not this use of carbonates triggers 40 CFR part 98, subpart U, and at what level it is triggered.

One commenter noted that at a pharmaceutical manufacturing facility there would also be a significant listing of small operations and activities which use carbonate compounds in trace quantities, including the creation of reagent solutions, and wastewater treatment operations employing carbonate compounds for buffering, chemical precipitation, or solids stabilization. This commenter recommended that EPA implement a threshold of 2,000 tons per year of carbonates per facility, which would correlate to CO<sub>2</sub> emissions of about 1,000 tons per year.

One commenter requested that EPA incorporate a *de minimis* threshold to only include equipment where carbonate is present at greater than 10 percent by weight and heated to a temperature that allows for decomposition. This commenter suggested an alternative threshold, where EPA would require facilities to calculate CO<sub>2</sub> emissions from each type of carbonate used in quantities exceeding 2,000 tons per year.

**Response:** The rule language has been modified to specify that GHG emissions from miscellaneous carbonate use are required to be reported only from processes that consume at least 2,000 tons per year and, further, where the carbonates are heated to a temperature sufficient to allow the calcination reaction to occur. This modification to the definition of the source category allows facilities with minimal carbonate consumption and low amounts of GHG emissions to be excluded from reporting emissions.

### Method for Calculating GHG Emissions

**Comment:** Multiple commenters requested that EPA allow emission calculations to be based on carbonate fraction of the product instead of calcination fractions.

**Response:** The rule has been changed to allow emission calculations by either the mass of carbonate input/output or calcination fraction. These methods should provide comparable estimates of emissions.

The calcination fraction method calculates the amount of CO<sub>2</sub> emissions based on the amount of each carbonate that is calcined during the process. The mass and calcination fraction of each carbonate are measured and used with a default CO<sub>2</sub> emission factor to determine CO<sub>2</sub> emissions.

The carbonate fraction method calculates the amount of CO<sub>2</sub> emissions as a mass balance between the input and output amount of each type of carbonate. The masses are measured and used with a default CO<sub>2</sub> emission factor to determine CO<sub>2</sub> emissions.

The mass of carbonate input/output is determined by use of the same plant instruments used for accounting purposes or by direct measurement. Calcination fractions can be measured by the appropriate industry consensus standards that require laboratory analysis of each carbonate type. Alternatively, a default value of one can be used as the calcination fraction.

### Data Reporting Requirements and Records That Must Be Retained

**Comment:** One commenter requested that recordkeeping and reporting

requirements be exempted for carbonates kept on-site for emergency purposes (not manufacturing or equipment), such as for neutralizing a chemical spill. This commenter explained that when used, these emergency reserves of carbonate material typically generate insignificant amounts of CO<sub>2</sub> and should therefore be excluded from reporting requirements.

*Response:* The final rule does not cover carbonates that are used in quantities of less than 2,000 tons per year and that are not heated to the point of calcination. Also, this subpart does not include requirements for calculating and reporting CO<sub>2</sub> emissions from acid neutralization. Therefore, the use of carbonates in the manner described is not covered by the final rule.

*Comment:* One commenter noted that the required records are duplicated in proposed 40 CFR 98.217(a) and 98.217(c), and requested that EPA revise this so as not to place unnecessary costs on facilities.

*Response:* EPA agrees that asking facilities to maintain records on procedures used to ensure the accuracy of monthly carbonate consumption will be duplicative with maintaining records of all carbonate purchases and deliveries. This is especially true if purchase records are used to determine monthly carbonate consumption. We removed this duplicative recordkeeping requirement from the rule.

To improve the emissions verification process, 40 CFR 98.216 was reorganized and updated. Some data elements were moved from 40 CFR 98.217 to 40 CFR 98.216, and some data elements that a reporter must already use to calculate GHG as specified in 40 CFR 98.213 were added to 40 CFR 98.216 for clarity. All affected sources must follow the general recordkeeping provisions under 40 CFR part 98.3(g) in subpart A.

Commenters may also want to review Section II.M for the response on the general recordkeeping requirements and Section II.N of this preamble for the response on the emissions verification approach.

## V. Nitric Acid Production

### 1. Summary of the Final Rule

*Source Category Definition.* The nitric acid production source category consists of facilities that use one or more trains to produce weak nitric acid (30 to 70 percent in strength) through the catalytic oxidation of ammonia.

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

*GHGs to Report.* For nitric acid production facilities, report N<sub>2</sub>O process emissions from each nitric acid train.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

*GHG Emissions Calculation and Monitoring.* Reporters must calculate N<sub>2</sub>O process emissions for each nitric acid train. Calculate the emissions by multiplying the site-specific emission factor for each train by the measured annual nitric acid production for that train. Determine the site-specific emission factor for each train through an annual performance test to measure N<sub>2</sub>O from the absorber tail gas vent and the production rate for that train.

When N<sub>2</sub>O abatement devices (such as nonselective catalytic reduction) are used, adjust the N<sub>2</sub>O process emissions for the amount of N<sub>2</sub>O removed using a destruction efficiency factor. The destruction factor is the destruction efficiency and can be specified by the abatement device manufacturer or can be determined using process knowledge or another performance test.

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

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

### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart V: Nitric Acid Production."

- The re-testing trigger was changed. Performance testing to determine the N<sub>2</sub>O emissions factor is required annually and whenever new abatement

technology is installed. The performance test should be conducted under normal operating parameters.

- Equation V-2 was edited to correct a calculation error and to allow multiple types of abatement technologies.

- Reorganized and updated 40 CFR 98.226 to improve the emissions verification process. Some data elements were moved from 40 CFR 98.227 to 40 CFR 98.226, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.223 were added to 40 CFR 98.226 for clarity.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on nitric acid production were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart V: Nitric Acid Production."

#### GHGs To Report

*Comment:* Multiple commenters asked that the language in 40 CFR 98.222(b) be clarified to include emissions under 40 CFR part 98, subpart V only from units that are 100 percent dedicated to nitric acid production to avoid double counting of combustion emissions.

*Response:* We appreciate the comments but have decided not to make any changes to 40 CFR part 98, subpart V. According to the applicability criteria in subpart C, all combustion unit emissions from nitric acid facilities (regardless of whether or not the combustion units are associated with nitric acid production operations) are to be reported under subpart C. There will be no potential for double counting of combustion emissions at the facility because Subpart V provides methods for reporting only the process emissions. *Also see* the preamble for responses on comments related to Subpart C (General Stationary Combustion).

#### Method for Calculating GHG Emissions

*Comment:* Multiple commenters asked that the requirement to repeat the annual performance test be removed. In the proposal, re-testing was triggered whenever the nitric acid production rate changed by more than 10 percent. Commenters asserted that production depends on demand for nitric acid and often varies by up to 20 percent.

*Response:* We appreciate the comments and have decided to eliminate re-testing. We believe that

annual determination of the N<sub>2</sub>O emissions factor is sufficient to accurately calculate N<sub>2</sub>O emissions as long as the train equipment remains consistent over the year-long period (i.e., no installation of abatement technology).

*Comment:* Multiple commenters asked that alternative methods be allowed for calculating N<sub>2</sub>O emissions from nitric acid production. Specifically the commenters asked that EPA allow the use of N<sub>2</sub>O and flow CEMS to directly measure N<sub>2</sub>O emissions and use the performance test to evaluate the CEMS accuracy. They also requested that EPA allow use of existing process flow meters, process N<sub>2</sub>O analyzers to determine the amount of N<sub>2</sub>O sent to control devices and conduct a performance test measuring control device destruction efficiency for each control device and then calculate N<sub>2</sub>O emissions.

Commenters also asked that finalizing a methodology for N<sub>2</sub>O stack testing for nitric acid units be delayed until EPA can coordinate with the commenters in formulating a more accurate means of measurement from these sources.

*Response:* We agree that there are other accurate means of determining N<sub>2</sub>O emissions, such as N<sub>2</sub>O CEMS. The final rule has been changed to allow alternative test methods, in addition to the proposed methods. Any alternative must be approved by the Administrator before being used to comply with this rule. An implementation plan that details how the alternative method will be implemented must be included in the request for the alternative method. Currently there is no EPA method for using N<sub>2</sub>O CEMS. EPA understands the need to further evaluate and establish alternative comparable or potentially more accurate methods for sources to use in calculating N<sub>2</sub>O emissions from nitric acid production and will address this in future rulemakings or amendments to rulemaking. Until the method is approved, facilities must use the alternatives proposed in the rule for a performance test. At minimum the performance test will help to QA/QC alternative methods currently used to monitor N<sub>2</sub>O emissions (including N<sub>2</sub>O CEMS).

The final rule allows the use of existing process flow meters and process knowledge in the determination of the destruction efficiency of N<sub>2</sub>O abatement technologies. This parameter is often based on site-specific knowledge of operations in combination with manufacturer specifications. We believe that using existing methods reduces the potential cost impacts of this rulemaking and that it is in the best

interest of the facilities that required parameters be accurately measured.

*Comment:* Multiple commenters asked that Equation V-2 be edited to follow the summation format used in the IPCC Tier 2 methodology. The current format does not allow for multiple abatement technologies (including no abatement).

*Response:* We agree with this comment. The equation in the proposed rule contained an error and did not allow for multiple abatement technologies. The final rule contains a corrected version of the equation.

#### Data Reporting Requirements

*Comment:* Multiple commenters argued that the annual production rates, capacity and operating hours are considered CBI and should not be reported. The commenters asked that this information be maintained by the facility and made available to the Agency upon request.

*Response:* We reviewed CBI comments received across the rule (both general and subpart-specific comments) and our response is discussed in Section II.R of this preamble and in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues." See also Section II.N of this preamble for the response on the emissions verification approach.

We agree that annual operating hours are not used in the calculation of N<sub>2</sub>O emissions and this parameter has been moved to recordkeeping. However, this parameter is still important for emissions verification. This information can help to verify anomalies in emissions data if there were temporary shutdowns, etc.

We disagree that production be maintained as records rather than be reported. Nitric acid production is a parameter in the method for determining annual N<sub>2</sub>O emissions so we need production rate in order to verify the N<sub>2</sub>O emissions that are being reported. The internal verification system ensures that the GHG emissions reported are as accurate as possible.

We disagree that capacities be considered confidential information. During the data gathering process, we located multiple publicly available sources that included production capacities for nitric acid production facilities. Capacity information can help EPA determine a reasonable range within which reported emissions should be. We agree that capacities are not used in the calculation of N<sub>2</sub>O emissions; however, this is still an important parameter for verifying emissions. Therefore, this parameter has been moved to recordkeeping.

#### W. Oil and Natural Gas Systems

At this time, EPA is not going final with the fugitive and vented methane emissions from the oil and gas sector under 40 CFR part 98, subpart W. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

EPA received a number of lengthy, detailed comments regarding 40 CFR part 98, subpart W. Commenters generally opposed the proposed reporting requirements and thought they would entail significant burden and cost. For example, many commenters asserted that use of direct measurement to collect data required under 40 CFR part 98, subpart W would entail significant burden and that the proposal lacked standards for leak detection and measurement equipment. In many cases, commenters provided alternative approaches to the reporting requirements proposed by EPA such as the use of emission factors and/or reducing the number of sources and sites requiring direct measurement e.g., through statistical sampling. In addition to comments on burden, commenters requested clarification from EPA on a number of proposed reporting provisions.

As EPA received extensive comments on this subpart, EPA plans to take additional time to perform additional analysis and consider alternatives to data collection procedures and methodologies. These alternatives will provide similar coverage of vented and fugitive methane and other GHG emissions in the oil and gas sector, while concurrently taking into account industry burden. As stated in Section V.W of the preamble to the proposed rule (74 FR 166606, April 10, 2009), EPA will also consider the inclusion of GHG reporting from other sectors of the oil and gas industry.

Where applicable, EPA will also consider the applicability of engineering estimates, emissions modeling software and emissions factors rather than relying so extensively on the use of direct measurement. EPA will consider optimal methods of data collection in order to maximize data accuracy, while considering industry burden.

#### X. Petrochemical Production

##### 1. Summary of the Final Rule

*Source Category Definition.* The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, with certain exceptions. Exceptions include processes that produce a petrochemical

as a byproduct, processes that produce methanol from synthesis gas when the annual mass production of hydrogen or ammonia exceeds the annual mass of methanol produced, direct chlorination processes operated independently of oxychlorination processes to produce ethylene dichloride, processes that produce bone black, and processes that produce a petrochemical from bio-based feedstock.

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

**GHGs to Report.** For petrochemical production facilities, report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O process emissions from each petrochemical production unit. Process emissions include CO<sub>2</sub> generated by reaction in the process. Process emissions also include CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions generated by combustion of off-gas from the process in stationary combustion units and flares. For some of the GHG emission calculation and monitoring options, 40 CFR part 98, subpart X references procedures in 40 CFR part 98, subpart C for calculating emissions from stationary combustion sources, and it references procedures in 40 CFR part 98, subpart Y for calculating emissions from flares.

In addition, report GHG emissions for other source categories at the facilities for which calculation methods are provided in the rule, as applicable. For example, report CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit on site that does not burn process off-gas under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). The quantity of CO<sub>2</sub> captured must also be reported by following the requirements of 40 CFR part 98, subpart PP.

**GHG Emissions Calculation and Monitoring.** CO<sub>2</sub> process emissions from petrochemical production must be determined by one of three methods. Process emissions include emissions from CO<sub>2</sub> generated by chemical reactions in the process and from the combustion of process off-gas and liquid wastes.

One emission calculation option is to route all process vent emissions to one or more stacks and use CEMS to measure the CO<sub>2</sub> emitted from each stack (except flare stacks). For each stack that includes emissions from combustion of process off-gas, reporters must calculate CH<sub>4</sub> and N<sub>2</sub>O emissions by the procedures specified in 40 CFR part 98, subpart C. For each flare, the final rule requires CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions to be calculated using the procedures in 40 CFR 98.253(b)

(Petroleum Refineries). If CO<sub>2</sub> CEMS are used on all subject stacks, even if the CEMS were installed for reasons other than compliance with this rule, then the rule requires the use of this reporting option.

A second emission calculation option is to use a mass balance. Under this option, the quantity of each carbon-containing feedstock added to the process and the quantity of each carbon-containing product produced by the process must be measured for each calendar month, or it may be calculated based on measured changes in the liquid level in storage tanks. The carbon content of each feedstock and product also must be determined at least once per month. The carbon content may be measured directly, or it may be calculated based on measurements of the composition and known compound molecular weights. Under this option, the procedures for products also apply to byproducts and liquid organic wastes that are not combusted onsite. To prevent double-counting of combustion emissions, this option specifies that the procedures for stationary combustion sources in 40 CFR part 98, subpart C apply only to the supplemental fuel (e.g., natural gas) burned in combustion units that supply energy needs for petrochemical processes. The final rule specifies numerous measurement method options and related calibration requirements in 40 CFR 98.244. To potentially minimize the sampling and analysis burden, the final rule, like the proposed rule, includes an option that allows reporters to assume a feedstock or product is always 100 percent pure if they determine that the specified compound is always present at greater than 99.5 percent.

A third emission calculation option is available only for ethylene processes. Because nearly all process emissions from this process are from combustion of process off-gas, the final rule allows calculation of emissions from all stationary combustion units that burn process off-gas (with or without supplemental fuel) in accordance with the Tier 3 or Tier 4 procedures in 40 CFR part 98, subpart C. In addition, this option requires CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each flare to be calculated using the procedures in 40 CFR 98.253(b) (Petroleum Refineries).

**Data Reporting.** In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR 98.246.

**Recordkeeping.** In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR 98.247.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart X: Petrochemical Production."

- The definition of the source category was changed to exclude ethylene dichloride production by the direct chlorination process alone from the petrochemical production source category because the only GHG emissions from this process are from the combustion of supplemental fuel and the combustion of hydrocarbon emissions in air pollution control devices. Ethylene dichloride produced by both direct chlorination and oxychlorination in the "balanced process" is still part of the source category.

- For the mass balance option, the measurement and emission calculation frequency was changed from weekly to monthly.

- For ethylene processes, an alternative was added to the mass balance option that allows reporters to calculate emissions from stationary combustion sources that burn ethylene process off-gas (with or without supplemental fuel) using the Tier 3 or Tier 4 procedures in 40 CFR part 98, subpart C. This includes all such combustion units, including units that supply energy to processes other than the ethylene process. This option does not affect requirements for stationary combustion sources related to ethylene processes that burn no process off-gas; emissions from these combustion units still must be calculated using the methods in any applicable Tier in 40 CFR part 98, subpart C.

- The reporting requirements in 40 CFR 98.246 were reorganized and updated to facilitate the emissions verification process, simplify and clarify requirements, and address requirements for the new monitoring option for ethylene processes.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Many comments on petrochemical production were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart X: Petrochemical Production."

#### *Definition of Source Category.*

*Comment:* Several commenters stated that ethylene production should be removed from the petrochemical production source category because essentially all GHG emissions from such processes are from combustion sources, which would be subject to reporting under 40 CFR part 98, subpart C regardless of whether the process is included in the petrochemical production source category. According to two commenters, using a mass balance approach is irrelevant and confusing because ethylene processes have no normal process vents. One commenter noted that methane is produced in ethylene processes, but the vast majority is returned as fuel within the plant or another plant at the same site and thus would produce CO<sub>2</sub> emissions only when combusted. Another commenter noted that off-gas from ethylene processes that are co-located with a petroleum refinery or other chemical plants is sent to the fuel gas system where it is mixed with other process gases from non-ethylene units in a fuel gas blend drum and then distributed to combustion units throughout the refinery and/or chemical plant. According to two commenters, the mass balance approach is onerous due to the number of product streams that would have to be measured, and the results of a mass balance most likely would be less accurate than a fuel combustion methodology. These two commenters also noted that calculating GHG emissions based on fuel combustion is the methodology used currently by most ethylene units. One commenter suggested that as an alternative to excluding ethylene units from the petrochemical production source category, EPA could add an emission calculation methodology to 40 CFR part 98, subpart X that would allow facilities to calculate combustion emissions based on fuel consumption.

*Response:* As one commenter noted, methane (and other light ends) are generally burned in combustion units to supply energy needs for the ethylene process itself and possibly other processes. Emissions from combustion

of these process off-gases are process emissions that are intended to be reported under 40 CFR part 98, subpart X. At facilities where the ethylene process off-gases are not mixed with off-gas from other processes, we do not believe that the mass balance approach is illogical; the flows and carbon contents of feedstocks and products can be determined for an ethylene process, and the resulting values can be used in the mass balance equations, just as they can for any other petrochemical process. Furthermore, we do not know if the views of the commenters reflect the views of all ethylene manufacturers. Therefore, we have retained ethylene in the petrochemical production source category, and we have retained the mass balance option in the final rule.

Although we still think a mass balance approach is appropriate and valid for ethylene processes, we have also evaluated combustion-based methodology options for the final rule. Given that the cracking and separation operations generate negligible CO<sub>2</sub>, we agree with the commenters that the only significant source of emissions in ethylene production is from combustion operations. One concern we have with using the Tier 1 and Tier 2 methodologies in 40 CFR part 98, subpart C is that they rely on default emission factors and company records (rather than measurements) of fuel flow. Given the variety of feedstocks and the corresponding variety in process off-gas, we do not believe default emission factors or fuel flow based on company records are appropriate. Therefore, we rejected the Tier 1 and Tier 2 methodologies. On the other hand, Tier 3 requires measurement of the total fuel flow and relatively frequent measurement of the carbon content of the fuel. Using CEMS to measure CO<sub>2</sub> emissions (i.e., the Tier 4 methodology in 40 CFR part 98, subpart C) is also a good way to measure CO<sub>2</sub> emissions from any combustion unit. Therefore, we determined that use of the Tier 3 or Tier 4 methodology is acceptable for calculating emissions from combustion units that burn ethylene process off-gas (with or without mixing with supplemental fuel), and these options are included in the final rule. In addition, because the methodology used for calculating emissions from one combustion unit has no bearing on the emissions from any other combustion unit, the final rule states that a facility is not required to use the same Tier for each stationary combustion unit.

*Comment:* One commenter requested that EPA remove ethylene dichloride (EDC) from the petrochemical source category because EDC is not

manufactured using a fossil fuel-based feedstock (e.g., crude oil, naphtha, natural gas condensate, methane, or other fossil fuel-based chemicals), no GHGs are used in the manufacturing process, and only a trace amount of CO<sub>2</sub> is generated in the process. Another commenter requested clarification that EDC produced as an intermediate in the production of vinyl chloride monomer is not part of the petrochemical source category because the entire process is considered to be an "integrated process", and the primary product of the process is not EDC. The commenter noted that the term "primary product" is also used in the Hazardous Organic NESHAP (HON) (40 CFR part 63, subpart F), but it has a different definition. To avoid confusion created by multiple definitions for the same term, the commenter urged EPA to consider alternatives to the concept of primary product for determining applicability of an integrated process.

*Response:* EDC is produced by two processes. In one process, the direct chlorination process, ethylene is reacted with chlorine to create EDC. As the commenters noted, reactions in this process produce negligible CO<sub>2</sub> emissions and no other GHG emissions. The only GHG emissions associated with this process are from the combustion of process off-gas and supplemental fuel. We have determined that monitoring and reporting of these emissions will be required under 40 CFR part 98, subpart C. Therefore, we have removed this process from the petrochemical source category.

In the second EDC process, the oxychlorination process, ethylene is reacted with hydrochloric acid to create EDC and water. Some of the ethylene, however, oxidizes to CO<sub>2</sub> and water in a competing side reaction. All facilities in the United States (U.S.) that operate this process operate it as part of an integrated process that includes vinyl chloride monomer production and a direct chlorination process. This integrated process is called a "balanced process". Although available estimates suggest the amount of CO<sub>2</sub> emitted is small relative to emissions from combustion, we do not have data to support such estimates. Furthermore, even if small relative to other sources, the total amount is not necessarily insignificant. We continue to believe information about these emissions is needed in order to support future policy decisions regarding petrochemical processes. Therefore, we have not removed EDC production by the balanced process from the petrochemical production source category.

In the proposed rule, an “integrated process” was defined as “a process that produces a petrochemical as well as one or more other chemicals that are part of other source categories” subject to reporting under 40 CFR part 98. This concept does not apply to production of EDC as an intermediate that is used in the onsite production of vinyl chloride monomer because vinyl chloride monomer production is not a source category that is subject to reporting under 40 CFR part 98. We used general language in the proposed rule that would apply to various integrated process scenarios, but the only scenario we know of that meets these conditions is methanol production from synthesis gas that is sometimes also used to produce hydrogen and/or ammonia (both of which are subject to reporting under other subparts in 40 CFR part 98). Because this is the only situation where the “integrated process” concept would apply, we decided to replace it in the final rule with language in 40 CFR 98.240 that explicitly states the applicability determination procedures for a process that produces methanol, hydrogen, and/or ammonia from synthesis gas. Thus, the term “primary product” has also been removed from the final rule, which eliminates the potential conflict with the definition in the HON.

#### Method for Calculating GHG Emissions

*Comment:* Two commenters stated that the proposed CEMS requirements are overly restrictive. According to these commenters, a facility should have the option to install a CEMS on one or more sources without being required to have a CEMS on all sources associated with a petrochemical production process. For example, the commenters suggested that a facility should have the flexibility to use a CEMS on a large emission point while being allowed to use the combustion equations and/or the mass balance approach for smaller emission points in the process (e.g., start-up heaters and steam jet exhausts from distillation columns operating under vacuum).

*Response:* If some emissions were from stacks monitored with CEMS and all other emissions were from combustion units without CEMS, it would be possible to use a combination of CEMS and the combustion equation methodology to calculate the total GHG emissions from a petrochemical process. However, this scenario is unlikely, which means other methodology would be needed to estimate emissions from other emission points (e.g., the steam jet exhausts cited by the commenters). It is not clear to us how the mass balance

methodology would be used to estimate these other emissions because the mass balance relies on knowledge of the total carbon input to the process and the total amount of carbon in all products (and organic liquid wastes); the difference is assumed to be the total CO<sub>2</sub> emissions. Theoretically, other methodology could be developed to calculate emissions from specific other emission points, but the commenter has not suggested other techniques. Therefore, the final rule does not include an option to mix CEMS with other methodology for a given process unit.

*Comment:* According to several commenters, weekly measurements of feedstocks and products are burdensome or unwarranted. Two commenters suggested changing the frequency to monthly because monthly accounting would align better with existing industry accounting procedures, reduce the burden, and provide 12 high-quality estimates per year. One commenter suggested monthly mass balance calculations for carbon black facilities because the emissions from a carbon black manufacturing facility do not vary significantly from week to week. Another commenter requested a provision to allow the reporter to determine a sampling frequency that is consistent with the variability of the stream.

*Response:* We are sensitive to the burden imposed by the rule and want to minimize it when possible. Based on the results of an uncertainty analysis (see memorandum entitled “Monte Carlo Simulation of Uncertainty in Monitoring Frequency for Mass Balance Option for Petrochemical Production Facilities” in the docket) we believe longer monitoring periods will not significantly compromise the monitoring results for the mass balance option. Therefore, the mass balance option in the final rule requires monthly monitoring instead of the proposed weekly monitoring.

#### Data Reporting Requirements

*Comment:* Two commenters stated that the proposed reporting requirements are excessive, particularly information such as each carbon content measurement and information on the calibration of each flow meter. According to the commenters, submitting this information will not improve the overall quality of the GHG emission calculation, and it is not necessary because the facilities are required to certify that the submitted information is true, accurate, and complete. Therefore, the commenters recommended that facilities be required

to retain records of such information rather than submit it in reports.

*Response:* A primary reason that additional information beyond annual emissions must be reported is so that EPA can verify the results. To facilitate the emissions verification process, 40 CFR 98.246 was reorganized and updated. For example, the final rule requires reporting of all input data used in the emission calculation equations, not just the carbon content values and the annual quantities, because this information is needed so the calculations can be reproduced and confirmed as part of the emissions verification process. Note, however, that any increase in the burden to report flow measurements has been offset by the reduction in monitoring frequency from weekly to monthly. The reporting requirements in the final rule for the mass balance option also have been simplified and clarified by replacing the requirement to submit all information related to uncertainty estimates with a requirement to submit only the dates and summarized results of measurement device calibrations. The estimated accuracy of measurement devices and the technical basis for such measurements must also be documented as part of the monitoring plan that is maintained onsite. The reporting section also was updated to include reporting requirements for the new monitoring option for ethylene processes.

#### Y. Petroleum Refineries

##### 1. Summary of the Final Rule

###### i. Source Category Definition

Petroleum refineries are facilities that produce gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) by the distillation of petroleum or the redistillation, cracking, or reforming of petroleum derivatives. The definition of petroleum refineries excludes facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation), regardless of the products produced.

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

###### ii. GHGs to Report

The refinery processes and gases that must be reported are listed in Table Y-1 of this preamble along with the rule subpart that specifies the calculation methodology that must be used.

TABLE Y-1—GHGS TO REPORT

For this refinery process . . .	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated . . .		
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Stationary combustion .....	C	C	C
Flares .....	Y	Y	Y
Catalytic cracking .....	Y	Y	Y
Traditional fluid coking .....	Y	Y	Y
Fluid coking with flexicoking design .....	C/Y	C/Y	C/Y
Delayed coking .....	—	Y	—
Catalytic reforming .....	Y	Y	Y
Onsite and offsite sulfur recovery .....	Y	—	—
Coke calcining .....	Y	Y	Y
Asphalt blowing .....	Y	Y	—
Equipment leaks .....	—	Y	—
Storage tanks .....	—	Y	—
Other process vents .....	Y	Y	Y
Uncontrolled blowdown systems .....	—	Y	—
Loading operations .....	—	Y	—
Hydrogen plants (nonmerchant) .....	P	P	—

**Key:**

- C = 40 CFR part 98, subpart C (General Stationary Combustion Sources).
- P = 40 CFR part 98, subpart P (Hydrogen Production).
- Y = 40 CFR part 98, subpart Y (Petroleum Refineries).
- = Reporting from this process is not required.

iii. GHG Emissions Calculation and Monitoring

Under 40 CFR part 98, subpart Y, petroleum refineries must calculate CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions using the calculation methods described below for each refinery process.

For CO<sub>2</sub> emissions, reporters must use CEMS or specified calculation methods as follows:

- For refinery units with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology of 40 CFR part 98, subpart C to report combined process and combustion CO<sub>2</sub> emissions.
- For refinery units without CEMS in place, reporters can elect to either (1) install and operate a CEMS to measure combined process and combustion CO<sub>2</sub> emissions according to the requirements specified in 40 CFR part 98, subpart C or (2) calculate CO<sub>2</sub> emissions using the methods summarized below.

*Flares.* CO<sub>2</sub> emissions from flares must be calculated using the gas flow rate (either measured with a continuous flow meter or calculated using engineering calculations) and either: (1) At least weekly measured carbon content of the flare gas, or (2) at least weekly measured heat content of the flare gas and an emission factor provided in the rule. If the carbon content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare use is allowed, but CO<sub>2</sub> emissions for each startup, shutdown, and malfunction event

exceeding 500,000 standard cubic feet (scf) per day of flare gas must be calculated separately using engineering estimates of the quantity of gas discharged and the carbon content of the flared gas. CH<sub>4</sub> and N<sub>2</sub>O emissions from flares must be calculated using the methods specified in 40 CFR part 98, subpart Y.

*Catalytic Cracking Units, Fluid Coking Units, and Catalytic Reforming Units.* CO<sub>2</sub> emissions must be calculated using the volumetric flow rate of the exhaust gas (measured or calculated) and hourly measured carbon monoxide (CO) and CO<sub>2</sub> concentrations in the exhaust stacks from the catalytic cracking unit regenerator and fluid coking unit burner from units exceeding 10,000 barrels per stream day. Catalytic cracking and fluid coking units below this threshold must use the required flow and gas monitors if they are in-place, but may use engineering estimates for determining CO<sub>2</sub> emissions if the required flow and gas monitors are not in place. Similarly, catalytic reforming units may use the flow and gas monitors required for large catalytic cracking and fluid coking units; alternatively, reporters may use engineering estimates based on the quantity of coke burned off, the carbon content of the coke (using either a measured or a default value), and the number of regeneration cycles. CH<sub>4</sub> and N<sub>2</sub>O emissions may be measured or may be calculated using the CO<sub>2</sub> emissions and default emission factors. Fluid coking units that use the flexicoking

design may account for their GHG emissions either by using the methods specified for traditional fluid coking units, or by using the methods for stationary combustion specified in 40 CFR part 98, subpart C.

*Onsite and Off Site Sulfur Recovery.* CO<sub>2</sub> emissions must be calculated using the volumetric flow rate of the sour gas (measured continuously or calculated from engineering calculations) and the carbon content of the sour gas stream (using a measured or a default value).

*Coke Calcining Units.* CO<sub>2</sub> emissions must be calculated from the difference between the carbon input as green coke and the carbon output as marketable petroleum coke and as coke dust collected in the dust collection system. The CH<sub>4</sub> and N<sub>2</sub>O emissions from coke calcining units may be measured or calculated using the calculated CO<sub>2</sub> emissions and default emission factors.

*Asphalt Blowing Operations.* For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, CH<sub>4</sub> and CO<sub>2</sub> emissions must be calculated using a facility-specific emission factor based on test data or, where test data are not available, a default emission factor provided in the rule. For asphalt blowing operations controlled by a thermal oxidizer or flare, CH<sub>4</sub> and CO<sub>2</sub> emissions must be calculated by assuming 98 percent of the CH<sub>4</sub> and other hydrocarbons generated by the asphalt blowing operation are converted to CO<sub>2</sub>.

*Delayed Coking Units.* CH<sub>4</sub> emissions from the depressurization of delayed

coking vessels must be calculated using the method outlined below for other process vents. The emissions released during the opening of vessels for coke cutting operations must be calculated using the vessel parameters (height and diameter), vessel pressure, the number of times the vessel was opened, the void fraction of the coking vessel prior to steaming, and the mole fraction of CH<sub>4</sub> in the gas released (using a measured or a default value provided in the rule). The rule provides an alternative of using only the vessel parameter equation if no water or steam is added to the vessel after the vessel is vented to the atmosphere.

**Other Process Vents.** GHG emissions from other process vents that contain CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O exceeding concentration thresholds specified in the rule must be calculated using the volumetric flow rate, the mole fraction of the GHG in the exhaust gas, and the number of hours during which venting occurred.

**Uncontrolled Blowdown Systems.** CH<sub>4</sub> emissions from uncontrolled blowdown systems must be calculated using either the method specified for process vents or a default emission factor and the sum of crude oil and intermediate products received from off site and processed at the facility.

**Equipment Leaks.** CH<sub>4</sub> emissions from equipment leaks must be calculated using either default emission factors or process-specific CH<sub>4</sub> composition data and leak data collected using the leak detection methods specified in EPA's Protocol for Equipment Leak Emission Estimates.

**Storage Tanks.** For storage tanks covered by the requirements of this rule, the methodology used to calculate the CH<sub>4</sub> emissions depends on the material stored. For storage tanks used to store unstabilized crude oil, facilities must use either: (1) The CH<sub>4</sub> composition of the unstabilized crude oil (based on direct measurement or product knowledge) and the measured gas generation rate; or (2) an emission factor-based method using the quantity of unstabilized crude oil received at the facility, the pressure difference between the previous storage pressure and atmospheric pressure, the mole fraction of CH<sub>4</sub> in the vented gas (using either a measured or a default value), and an emission factor provided in the rule. For storage tanks used to store material other than unstabilized crude oil with a vapor-phase CH<sub>4</sub> concentration of 0.5 percent by volume or more, facilities must use either tank-specific methane composition data and applicable correlations in AP-42, Section 7.1 (as implemented in the TANKS Model

(Version 4.09D) or similar models) or a default emission factor provided in the rule.

**Loading Operations.** CH<sub>4</sub> emissions from loading operations must be calculated using vapor-phase methane composition data and the method in Section 5.2 of AP-42: "Compilation of Air Pollution Emission Factors." Facilities must calculate CH<sub>4</sub> emissions only for loading materials that have an equilibrium vapor-phase CH<sub>4</sub> concentration equal to or greater than 0.5 percent by volume. Other facilities may assume zero CH<sub>4</sub> emissions.

#### iv. Data Reporting

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

#### v. Recordkeeping

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

#### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Y: Petroleum Refineries."

- The minimum monitoring frequency for flare gas heat value or carbon content was changed to weekly from daily. (For background on the selection of a weekly frequency, see memorandum entitled: "Uncertainty in Flare Estimates Based on Sampling Frequency" in the docket.) Engineering calculations are allowed in the final rule for reporters that do not monitor flare gas flow continuously or flare heating value or carbon content at least weekly.

- The minimum monitoring frequency for refinery fuel gas carbon content and molecular weight was changed to weekly from daily in 40 CFR part 98, subpart C for reporters that do not have continuous monitoring equipment, and we clarified in 40 CFR part 98, subpart Y that common (fuel)

pipe monitoring is allowed for petroleum refineries.

- We added a flare combustion efficiency of 98 percent, and we revised the equation for flare CH<sub>4</sub> emissions to account for uncombusted methane.

- The final rule allows engineering calculations to determine CO<sub>2</sub> emissions for catalytic cracking units and fluid coking units below 10,000 bbl/stream day that do not have CO<sub>2</sub>/CO/O<sub>2</sub> monitors already installed.

- The delayed coking unit depressurization emission equations and asphalt blowing equations were amended to address comments received.

- We added concentration thresholds for CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O from process vents below which GHG emissions are not required to be calculated and reported.

- The reporting requirements were updated to facilitate the emissions verification process.

#### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on petroleum refineries were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Y: Petroleum Refineries."

##### Definition of Source Category

**Comment:** Several commenters expressed concern that EPA defined a Petroleum Refinery so broadly that it could be interpreted to include chemical facilities that use petroleum-based materials as raw materials. Of particular concern was the term "\* \* \* and other products \* \* \*" which many commenters interpreted to include the manufacture of chemicals, synthetic rubber, and a variety of plastics. One commenter also requested clarification that "other products" did not include sulfur, ammonia, or hydrogen sulfide. Several commenters requested clarification that the definition of petroleum refineries did not include lube oil production or fuel blending operations if the products were produced without distilling, redistilling, cracking, or reforming of the petroleum derivatives.

**Response:** We have revised and clarified the definition of petroleum refinery to list a few additional refinery products (specifically gasoline blending stocks and naphtha) and deleted the term "or other products." We believe that this change clarifies that companies that use petroleum derivatives to make

only petrochemicals, plastics, synthetic rubber, sulfur, or any other product other than those specifically listed are not considered petroleum refineries. We feel the definition also clearly excludes lube oil manufacturing provided the lube oil manufacturer does not distill, redistill, crack, or reform the petroleum derivatives at the facility.

*Comment:* Numerous commenters requested that many of the emission sources for which 40 CFR part 98, subpart Y required reporting were small and should not have to be reported. Several commenters noted that EPA's TSD for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases, indicates that 92.9 percent of the refining sector's GHG emissions come from two sources, combustion and catalytic coke operations. The remaining 7.1 percent of emissions come from eight distinct categories, including: Hydrogen plants (2.7 percent); Sulfur Plants (1.9 percent); Flaring (1.6 percent); Wastewater Treatment (0.43 percent); Blowdown (0.18 percent); Asphalt Blowing (0.10 percent); Delayed Coking (0.058 percent); Equipment Leaks (0.014 percent); Storage Tanks (0.007 percent); and Cooling Towers (0.003 percent). The commenters argued that the burden associated with the collection of data as prescribed in the proposed rule is not warranted for small sources and/or not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions.

*Response:* The TSD estimates are based largely on engineering estimates without significant supporting data. For the smaller sources, we have provided very simple methods to calculate the GHG emissions from these sources to minimize the monitoring, recordkeeping, and reporting burden associated with these sources when no measurement data are available. However, requiring reporting for these sources will provide EPA with valuable data to better characterize them and provide a better record upon which to formulate decisions regarding whether to include or exclude these sources from future GHG policy decisions. Additionally, while some of these sources are currently believed to be small compared to the larger sources present at petroleum refineries, they are not necessarily insignificant. The inclusion of reporting data for these sources is critical to support analysis of future policy decisions for petroleum refineries.

*Comment:* Several commenters objected to the mandatory reporting of CH<sub>4</sub> and N<sub>2</sub>O emissions within the Petroleum Refinery source category.

Many commenters cited the TSD, which indicated that N<sub>2</sub>O emissions account for 0.09 percent of the GHG emissions and CH<sub>4</sub> account for only 0.87 percent of the GHG emissions. The commenters argued that the measurement error for the larger sources (stationary combustion sources and catalytic cracking unit coke burn-off) exceeds the contributions of these sources. As such, the commenters stated that the burden associated with reporting these emissions is not warranted and/or not consistent with EPA's stated intended purpose of the rule which is to support analysis of future policy decisions.

*Response:* The TSD estimates for CH<sub>4</sub> and N<sub>2</sub>O are based largely on engineering estimates without significant supporting data. We specifically require reporting of these various GHGs to obtain better data by which to support future policy analysis. Moreover, EPA has pending before it a petition to reconsider the recently revised New Source Performance Standard (NSPS) for petroleum refineries asking EPA to reconsider, among other things, whether to establish GHG standards under section 111 for refineries. As such, we have a keen interest in obtaining improved GHG emissions data in order to better analyze policy options. For instance, refineries are a significant source of NO<sub>x</sub> emissions, but we have no data to determine the fraction of NO<sub>x</sub> that is N<sub>2</sub>O. With the increased use at refineries of NO<sub>x</sub> control devices, such as low-NO<sub>x</sub> burners, low excess air, selective catalytic reduction (SCR) systems, and selective non-catalytic reduction (SNCR) systems, it seems plausible that N<sub>2</sub>O may be a more significant portion of a refinery's NO<sub>x</sub> emissions. Thus, if a facility has measurement data for a source, the reporting of these data are important for better understanding the impact of current and future policy options. Consequently, we have provided additional alternatives that allow the use of measured N<sub>2</sub>O (and CH<sub>4</sub>) emissions or site-specific emission factors in addition to the default factors. Nonetheless, we have provided very simple default methods to calculate the emission of these GHGs when measurement data are not available. While emissions of CH<sub>4</sub> and N<sub>2</sub>O may not be large comparatively, the reporting method for these pollutants is straightforward and commensurate with the anticipated emissions contribution.

*Method for Calculating GHG Emissions*

*Comment:* Several comments objected to the requirements for flares, particularly the requirements for SSM

events. Some commenters also stated that daily sampling was too burdensome. The commenters suggested that flare emissions be dropped from the rule or that refineries be allowed to perform a one-time calculation. One commenter noted that the proposed equation did not account for flare combustion efficiency, which was inconsistent with other subparts, and recommended that a flare efficiency factor be added to the equation to calculate the CO<sub>2</sub> emissions from flares.

*Response:* EPA needs accurate data on flare emissions to better understand this emission source, as flare use can vary significantly from day-to-day and year-to-year. Use of flares is too episodic and variable to allow a one-time calculation. However, we recognize that flares may contribute about two percent of a refinery's GHG emissions. Therefore, we sought to reduce the burden associated with the flare monitoring and reporting requirements. As proposed, special calculations for SSM events were only required if daily measurement data were not available. In this final rule, we allow weekly monitoring of flare use without triggering special SSM event calculations, which should lessen the burden associated with calculating flare emissions while not significantly changing the accuracy of the data. Additionally, we included a threshold flaring rate of 500,000 scf/day for SSM events. Only SSM events exceeding this gas flare rate require special SSM calculations in the final rule. Some consent decree requirements and State rules require root cause analysis and quantification of emission events exceeding 500,000 scf/day. We consider events of this magnitude to be significant and believe a separate analysis is justified in addition to the procedures that apply to routine operation. We have also revised the equations for CO<sub>2</sub> and CH<sub>4</sub> to account for flare combustion efficiency.

*Monitoring and QA/QC Requirements*

*Comment:* Several commenters argued that the monitoring and QA/QC requirements were excessive and that EPA significantly underestimated the costs associated with complying with the reporting requirements under 40 CFR part 98, subpart Y. One commenter noted that existing facility CO<sub>2</sub> CEMS, HHV monitors, carbon content monitors, and flow meters are not necessarily for "regulatory" purposes and thus may not meet the accuracy requirements of the rule. The commenter suggested many more refineries would have to add or replace monitors as a result of the rule. Many commenters suggested EPA significantly

underestimated the labor hours required to collect and analyze daily samples as well as to develop and implement a QA plan. Various commenters supplied labor or cost estimates for various requirements in the rule, including costs of implementing an LDAR program and flare SSM calculations. Several commenters stated that the requirement to use a CEMS for monitoring CO<sub>2</sub> from the catalytic cracking unit was expensive and burdensome, especially for small refineries that do not have a CEMS infrastructure.

*Response:* We have significantly revised our rule requirements for petroleum refineries and stationary combustion sources to reduce burden to the industry. We have provided in the final rule (in 40 CFR part 98, subpart C) a default emission factor for refinery (still) gas to allow combustion sources that combust refinery gas and meet the applicability requirements in 40 CFR part 98, subpart C to use Tier 2 methods. For sources that do not meet the Tier 2 requirements, weekly monitoring for refinery fuel gas under Tier 3 (40 CFR part 98, subpart C) and for flare gas (40 CFR part 98, subpart Y) is allowed. We have also re-assessed our costs based on the comments received and increased the labor hours estimated to collect and analyze samples, develop QA plans, and to perform QA/QC of existing equipment. We did review our QA/QC requirements and see no validity to the argument that our QA/QC requirements are so stringent that refineries will have to replace existing monitors to comply with the rule. While we note that some cost elements suggested by commenters are relevant and have been addressed in the changes in the labor estimates for sampling, analysis, and QA/QC as described above, other cost elements suggested by commenters are not relevant. For example, revisions of LDAR programs are not required under the rule; the proposed and final rule specifically provides a simple process-based emission factor approach for estimating CH<sub>4</sub> emissions from equipment leaks. We are cognizant that refineries with small catalytic cracking units are most likely to elect a compliance option under 40 CFR part 63, subpart UUU that does not require monitoring of coke burn-off, so these small refineries are most likely the facilities that would have been required to install monitoring equipment under the proposed rule. After reviewing these costs and impacts on the small refineries, we have allowed engineering calculations to determine CO<sub>2</sub> emissions for catalytic cracking units below 10,000

bbl/stream day that do not have CO<sub>2</sub>/CO/O<sub>2</sub> monitors already installed.

Even though we have reduced the stringency of the rule in many places, our revised cost estimates indicate that the average cost per refinery is approximately 60 percent higher than projected at proposal. We believe our revised refinery costs accurately portray the burden associated with the final reporting requirements in 40 CFR part 98, subpart Y. Nonetheless, we continue to believe that the costs are reasonable for this rule, especially considering that petroleum refineries are among the larger sources of GHG emissions in the U.S.

### Z. Phosphoric Acid Production

#### 1. Summary of the Final Rule

*Source Category Definition.* The phosphoric acid production source category consists of facilities that use a wet-process phosphoric acid process to produce phosphoric acid. A wet-process phosphoric acid process line is any system that manufactures phosphoric acid by reacting phosphate rock and acid and is usually identified by an individual identification number in a CAA operating permit.

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

*GHGs to Report.* Report CO<sub>2</sub> emissions from each wet-process phosphoric acid process line.

In addition, report GHG emissions at each facility for other source categories for which calculation methods are provided in the rule, as applicable. For example, report CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

*GHG Emissions Calculation and Monitoring.* Calculate process emissions of CO<sub>2</sub> using one of two methods, as appropriate:

- Most reporters can elect to either (1) install and operating CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculate CO<sub>2</sub> emissions based on monthly measurements of the mass of phosphate rock consumed and inorganic carbon content of each grab sample of phosphate rock.

- However, if process CO<sub>2</sub> emissions from phosphoric acid production are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO<sub>2</sub> emissions, then the CEMS must be used to measure

and report combined CO<sub>2</sub> emissions from that stack. In such cases, the reporter cannot use the CO<sub>2</sub> calculation methodology outlined in approach (2) in the previous bullet.

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

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

#### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart Z: Phosphoric Acid Production."

- The rule was revised to allow the use of techniques from Part 60 and Part 63 for calculating the weight of phosphorous-containing rock.

- The missing data provisions were revised to allow the use of default inorganic carbon content values based on the origin of the phosphorous-containing rock, in addition to determining missing inorganic carbon contents of phosphate rock consumed using an arithmetic average of measured values from of inorganic carbon contents of phosphate rock of the appropriate origin preceding and following the missing data incident.

- 40 CFR 98.266 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.267 to 40 CFR 98.266, and some data elements that are already used to calculate GHG emissions as specified in 40 CFR 98.263 were added to 40 CFR 98.266 for clarity.

#### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on phosphoric acid production were received covering numerous topics shown below.

Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart Z: Phosphoric Acid Production.”

Selection of Threshold

*Comment:* Multiple commenters asked that phosphoric acid production units not be included as an “all-in” category. According to the commenters, the facilities are very minor sources of GHG emissions. The commenter conceded that most (if not all) would still fall within the reporting threshold requirement, but asserted that it was unnecessary to include all phosphoric acid production units as regulated facilities regardless of the amount of emissions. The commenters stated that EPA inaccurately suggests that these units are major emitters of GHGs which could have significant impacts on these minor sources.

*Response:* We acknowledge the comments and concerns; however the final rule retains the “all-in” applicability requirement for this source category. The “once in, always in” provision has been removed. The final rule now contains provisions to cease reporting if annual reports demonstrate emissions less than specified levels for multiple years. These provisions apply to all reporting facilities, including those with phosphoric acid production processes. The purpose of this rule is to collect information on emissions sources for future policy development. Requiring reporting for these sources will provide EPA with valuable data to better characterize GHG emissions from phosphoric acid production and provide a more credible position if EPA elects to exclude these sources from future GHG policy analyses. We also believe that the accurate assessment of the emissions from phosphoric acid production will address the commenters’ concerns about potential future impacts.

Commenters may also be interested in reviewing Section II.H of this preamble for the response on provisions to cease reporting.

Method for Calculating GHG Emissions and Monitoring and QA/QC Requirements

*Comment:* Multiple commenters asked that production measurements in this rule be consistent with the existing MACT and NSPS regulations for the phosphate industry. In these regulations, production measurement is determined by the mass of phosphate feed (as P<sub>2</sub>O<sub>5</sub>). Two commenters stated that the change would provide consistency, and ensure a reporting structure that fits with the actual practices of the industry.

*Response:* We agree with the commenters that consistency among EPA regulations is important. Therefore, the final rule allows for techniques from part 60 and part 63 to calculate the weight of phosphorous-containing rock. This request is consistent with the intent of the proposed rule. Under existing regulations in part 60 and part 63, phosphoric acid manufacturing facilities already measure the mass of phosphorous bearing feed on a ton/hour basis. This feed rate can be used to determine monthly phosphate rock consumption. Process CO<sub>2</sub> emissions from phosphoric acid production are calculated from the total phosphate rock consumption multiplied by the inorganic carbon content of that rock. Further, part 60 and part 63 establish the appropriate monitoring and QA/QC procedures for determining this feed rate.

Procedures for Estimating Missing Data

*Comment:* Multiple commenters asked that the final rule allow options for missing data. The commenters asked that the use of default carbon content values based on the origin of the rock be allowed if analytical data are unavailable. In addition, commenters requested that procedures be added for measurement of the mass of phosphate rock consumed, suggesting procedures similar to those in 40 CFR part 98, subpart C, the lesser of the maximum capacity of the system, the maximum rate the meter can measure, or best

available estimate based on available process data.

*Response:* We agree with the commenters on this point. The final rule has been changed to allow the use of a default factor (by origin of the phosphate rock) for each missing value of the inorganic carbon content of phosphate rock. Use of a default carbon value in place of the missing data will provide a reasonable estimate of the total emissions from the facility and will avoid assuming the maximum possible facility emissions when no data are available. These default values have been added to the final rule in Table Z-1 of 40 CFR part 98, subpart Z.

Missing data procedures have also been added as suggested for missing monthly estimates of the mass of phosphate rock consumed consistent with the later recommendation. Again use of the best available data based on all available process data will avoid assuming the maximum possible facility emissions when no data are available. Facilities must document and keep records of the procedures used for all such estimates.

AA. Pulp and Paper Manufacturing

1. Summary of the Final Rule

*Source Category Definition.* This source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated mills), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

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

*GHGs to Report.* Table AA-1 of this preamble lists the GHG emission sources at pulp and paper manufacturing facilities for which GHG emissions must be reported along with the rule subpart that specifies the calculation methodology.

TABLE AA-1—GHGS TO REPORT

	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated ...					
	CO <sub>2</sub>	Biogenic CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	Biogenic CH <sub>4</sub>	Biogenic N <sub>2</sub> O
For pulp and paper mills ...						
Chemical recovery furnace at kraft and soda facilities .....	C	AA	C	C	AA	AA
Chemical recovery combustion units at sulfite facilities .....	C	AA	C	C	AA	AA
Chemical recovery combustion units at stand alone semi-chemical facilities ..	C	AA	C	C	AA	AA
Lime kilns of kraft and soda facilities .....	AA/C	AA	AA/C	AA/C	AA	AA
Makeup chemicals used in pulp mills .....	AA					

TABLE AA-1—GHGS TO REPORT—Continued

For pulp and paper mills ...	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated ...					
	CO <sub>2</sub>	Biogenic CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	Biogenic CH <sub>4</sub>	Biogenic N <sub>2</sub> O
Stationary combustion units .....	C	C	C	C	C	C

**Key:**

C = 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

AA = 40 CFR part 98, subpart AA (Pulp and Paper Manufacturing).

AA/C = use 40 CFR part 98, subpart AA for GHG emission factor and subpart C to determine default High Heating Values.

*GHG Emissions Calculation and Monitoring.* Under 40 CFR part 98, subpart AA, reporters must calculate emissions from pulp and paper manufacturing facilities as follows:

• *Chemical recovery furnaces:*

Calculate biogenic CO<sub>2</sub> emissions from combustion of biomass in spent pulping liquor using:

—Measured quantities of spent liquor solids fired, site-specific high heating value (HHV), and default or site-specific emission factors for each chemical recovery furnace located at kraft or soda facilities.

—Measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids for each chemical recovery unit at sulfite or stand-alone semichemical facilities.

• Calculate CO<sub>2</sub> emissions from fossil fuels used in chemical recovery furnaces using direct measurement of fossil fuels consumed and default emission factors according to the Tier 1 methodology for stationary combustion sources in 40 CFR part 98, subpart C.

• Calculate CH<sub>4</sub> and N<sub>2</sub>O emissions as the sum of emissions from the combustion of fossil fuels and the combustion of biomass in spent pulping liquor, as follows:

—For fossil fuel emissions, use direct measurement of fuels consumed, a default HHV, and default emission factors according to the methodology for stationary combustion sources in 40 CFR 98.33(c).

—For biomass emissions, use measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emission factors.

—Lime kilns at kraft and soda facilities.

• *Lime kilns:* Calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from combustion<sup>21</sup> of fossil fuels in pulp mill lime kilns using direct measurement of fossil fuels consumed and default emission factors

<sup>21</sup> Biogenic CO<sub>2</sub> from the conversion of CaCO<sub>3</sub> to CaO in kraft or soda pulp mill lime kilns is accounted for in the biogenic CO<sub>2</sub> emission factor for the recovery furnace.

and HHV found in 40 CFR part 98, subparts AA and C, respectively.

• *Makeup chemicals:* Calculate CO<sub>2</sub> emissions from the use of makeup chemicals using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO<sub>2</sub> and the makeup chemicals.

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

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

2. Summary of Major Changes Since Proposal

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

• Language was added to clarify that 40 CFR part 98, subpart AA GHG emissions are to be reported for makeup chemicals added in the chemical recovery areas of pulp mills (as opposed to makeup chemicals used at paper coating and laminating facilities).

• The frequency of measurements for the spent liquor solids mass fired (TAPPI Test Method T 650), heating value (TAPPI Test Method T 684), and carbon content (ASTM D5373-08) was reduced from monthly to annually.

• An option to use data from existing online solids meters to determine the

annual mass of spent liquor solids fired is provided (in lieu of conducting an annual TAPPI Test Method T 650).

• The requirement to report quarterly data was eliminated.

• The reporting requirements were revised to specify units to standardize inputs into the data reporting system.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A number of comments on pulp and paper manufacturing were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart AA: Pulp and Paper Manufacturing.”

Definition of Source Category

*Comment:* Two commenters stated that literal interpretation of 40 CFR part 98, subpart AA could require any facility operating paper coating and laminating processes to report emissions for any system used to add makeup chemicals. The commenters requested that language be added to 40 CFR part 98, subpart AA to clearly exclude facilities not intended to be covered and which have not traditionally been part of the pulp and paper source category.

*Response:* Definitions of terms used in 40 CFR part 98, subpart AA are provided in 40 CFR 98.6 (in subpart A of part 98). The definition of “makeup chemicals” is specific to the chemical recovery areas of pulp mills and serves to limit the scope of the pulp and paper subcategory. As defined in § 98.6 (emphasis added):

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

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

Thus, we disagree that the rule could be interpreted to require any facility operating coating and laminating processes to report emissions for any system used to add makeup chemicals. This was not the intent of the rule. Nevertheless, we have added language consistent with the definition of "makeup chemicals" to 40 CFR 98.270(b)(5) and 98.272(e) to further clarify that GHG emissions are to be reported for systems adding makeup chemicals (CaCO<sub>3</sub> and Na<sub>2</sub>CO<sub>3</sub>) in the chemical recovery areas of pulp mills.

*Comment:* Commenters stated the rule should include categorical exemptions for emissions from the combustion of non-condensable gases (NCG), stripper off gases (SOG), tall oil and turpentine (small sources of GHG that are difficult to measure). The commenters noted that these streams are of biogenic origin. One commenter described safety issues associated with sampling these gas streams.

*Response:* Pulp mill NCG, SOG, tall oil and turpentine were discussed in the Proposed Rule TSD for the pulp and paper manufacturing sector. The Proposed Rule TSD noted that process vent gases such as NCG and SOG and the byproducts tall oil and turpentine are derived from biomass. We acknowledge the safety and measurement issues described by commenters regarding sampling of NCG and SOG streams. No methods are specified in the rule for calculation of GHG associated with combustion of NCG, SOG, tall oil and turpentine. Thus, calculation of these emissions is not required and there is no need for categorical exemptions.

#### Method for Calculating GHG Emissions

*Comment:* Commenters stated that monthly measurements of the mass of spent liquor solids, HHV, and carbon content of spent liquor solids are unnecessary. The commenters requested that EPA either allow default fuel carbon content and heating value for spent pulping liquor, or reduce the frequency of measurements to annually or every two years. Commenters noted that spent liquor HHV and carbon content are measured from time to time but less frequently than monthly. In addition, one commenter pointed out that chemical recovery furnaces often have online solids meters installed to provide continuous measurement of the mass of spent liquor solids entering the furnace for safety and process control reasons. This commenter requested that EPA allow use of such continuous measurement devices instead of requiring monthly measurement of the

mass of spent liquor solids with TAPPI Test Method T 650.

*Response:* We disagree with commenters that default fuel carbon content and high heating values should be allowed instead of measured values. These parameters are already measured by mills (though less frequently than monthly) and thus are available for use and more accurate than default values. We are reducing the frequency of fuel property measurements from monthly to annual. There is little monthly variation in fuel properties over the course of a year. Therefore, annual measurements are sufficient to develop site specific emission factors. This change also reduces the burden associated with complying with the rule. These changes have been incorporated throughout the text and equations of 40 CFR part 98, subpart AA.

In addition, the final rule allows use of either an annual measurement of the mass of spent liquor solids fired (with TAPPI Test Method T 650) or use of annual spent liquor solids data calculated from continuous measurements already performed for process control purposes (e.g., with existing online solids meters). If the annual spent liquor solids fired is determined using existing measurement equipment, then reporters must retain records of the calculations used to determine the annual mass of spent liquor solids fired from the continuous measurements in order to demonstrate, if necessary, that calculations were done correctly. Reporters must also document that these measurement devices have been regularly and properly calibrated according to the manufacturer's specifications.

#### Data Reporting Requirements

*Comment:* One commenter noted that presenting quarterly data in annual reports for pulp and paper manufacturing annual emissions, consumption of biomass fuels, and quantity of spent liquor solids fired is unnecessary for an annual reporting system.

*Response:* We have revised 40 CFR 98.276 and 98.277(a) to remove the requirement for providing quarterly details in the annual report. EPA agrees that requiring quarterly details was not necessary for ensuring the accuracy of data reported annually.

*Comment:* One commenter requested that the spreadsheets developed by the National Council for Air and Stream Improvement (NCASI) for the International Council of Forest and Paper Associations (ICFPA) be allowed as an option for facilities subject to the Rule to determine emissions. These

spreadsheets segregate calculated GHG emissions into fossil fuel and biogenic categories. The commenter believes that tools like those developed by NCASI and others should be allowed as an option for facilities subject to the emission calculation requirements imposed by 40 CFR 98.3. This streamlined approach will provide the Agency with valid GHG emission data without imposing extraordinary capital and labor burdens on the industry.

*Response:* The ICFPA/NCASI tools were considered in developing the requirements of the GHG reporting rule. However, the ICFPA/NCASI spreadsheets, though valuable tools, are not broadly applicable to all industrial sectors covered under the GHG reporting rule, as are the monitoring, reporting, recordkeeping, and emissions verification requirements specified in 40 CFR 98.3. Additionally, these tools often use default factors and estimates, which differs from the approach proposed by EPA. The data collected from all subparts of the GHG reporting rule will be tabulated in EPA's electronic reporting system. This system will be used to verify emission calculations and will require specific data be reported in order to run the calculations used for verification. The tools suggested by the commenter, however, would only provide a total emission number. Consequently, EPA would not be able to check the underlying calculations for accuracy. The final GHG reporting rule reflects the data reporting requirements necessary for emissions verification by EPA. Edits to the reporting and recordkeeping language (40 CFR 98.276 and 98.277) of 40 CFR part 98, subpart AA were made to clarify calculation inputs and units of measure to be reported. As part of the implementation phase of today's final rule, EPA intends to prepare guidance documents to assist the industry in complying with the rule's requirements. In recognition of the fact that the pulp and paper industry has been using the ICFPA/NCASI spreadsheets, EPA will consider including in the guidance materials a comparison between these spreadsheets and EPA's electronic reporting system to reduce the burden on the industry and minimize confusion.

#### BB. Silicon Carbide Production

##### 1. Summary of the Final Rule

*Source Category Definition.* The silicon carbide production source category consists of any process that produces silicon carbide for abrasive purposes.

Reporters must submit annual GHG reports for facilities that meet the

applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble.

*GHGs to Report.* Report process CO<sub>2</sub> and CH<sub>4</sub> emissions from all silicon carbide production furnaces or process units at the facility combined.

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable. For example, report CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

*GHG Emissions Calculation and Monitoring.* For CO<sub>2</sub> emissions, reporters must use one of the following methods, as appropriate:

- Most reporters can elect to calculate and report process CO<sub>2</sub> emissions from silicon carbide production processes by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculating emissions using the measured petroleum coke consumption and a monthly facility-specific emission factor. The facility-specific emission factor is the carbon content of the petroleum coke (provided monthly by the supplier or measured monthly using the appropriate test methods) adjusted for carbon in the silicon carbide product.

- However, if process CO<sub>2</sub> emissions from silicon carbide production are vented through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report process CO<sub>2</sub> emissions, then the CEMS must be used to measure and report combined CO<sub>2</sub> emissions from that stack. In such cases, the reporter cannot use the CO<sub>2</sub> calculation approach (2) outlined in the above bullet.

For CH<sub>4</sub> emissions, reporters must use the measured petroleum coke consumption and a default emission factor of 10.2 kilograms (kg) per metric ton of coke consumed.

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

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG

emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart BB.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart BB: Silicon Carbide Production."

- The emissions calculation method under 40 CFR 98.283(b) was revised to require data on monthly petroleum coke consumption and monthly petroleum coke carbon contents rather than quarterly determinations.

- Missing data procedures were added under 40 CFR 98.285 for monthly parameters used to calculate emissions, including mass of petroleum coke, and carbon contents of petroleum coke.

- 40 CFR 98.286 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.287 to 40 CFR 98.286, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.283 were added to 40 CFR 98.286 for clarity.

## 3. Summary of Comments and Responses

No specific comments were received pertaining to the proposed reporting requirements for silicon carbide production facilities. However, the proposed rule did not clearly specify how quarterly carbon contents should be determined. This determination should be made on a monthly basis as proposed for other chemical production processes where process emissions arise from use of petroleum coke, such as titanium dioxide production. Quarterly reporting of carbon contents of petroleum coke consumed for the quarter would have to be averaged from monthly data. For verification, EPA would require reporting of the monthly carbon contents of the petroleum coke. Therefore, we revised the emissions calculation method to directly require monthly petroleum coke consumption and monthly petroleum coke contents, rather than quarterly based on an arithmetic average of the monthly estimates to improve accuracy of emissions calculations. We have retained the flexibility in use of supplier data to determine carbon contents. We understand that most supplier data on carbon contents of petroleum coke is readily available and that businesses

track production inputs and outputs on a monthly basis as a part of normal business practice or existing accounting procedures. The increased frequency of data collection from quarterly to monthly provides greater clarity and accuracy without significantly increasing burden. In addition, see the Section II.N of this preamble for an explanation of the emissions verification approach.

## CC. Soda Ash Manufacturing

### 1. Summary of the Final Rule

*Source Category Definition.* A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by either: calcining trona or sodium sesquicarbonate; or by using a liquid alkaline feedstock process that directly produces CO<sub>2</sub>. In the context of the soda ash manufacturing sector, "calcining" means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

Soda ash produced from a liquid alkaline feedstock using sodium hydroxide does not emit process CO<sub>2</sub> and therefore is not subject to the requirements of Subpart CC. However, such facilities may be covered under Subpart C (General Stationary Combustion) if they meet the requirements of either § 98.2(a)(1) or (2).

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

*GHGs to Report.* For soda ash manufacturing, report the following emissions:

- CO<sub>2</sub> process emissions from soda ash manufacturing, reported for each manufacturing line.

- CO<sub>2</sub> combustion emissions from each soda ash manufacturing line.

- N<sub>2</sub>O and CH<sub>4</sub> emissions from fuel combustion at each soda ash manufacturing line under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.

- CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit other than soda ash manufacturing lines under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for any other source categories at the facility for which calculation methods are provided in other subparts of the rule, as applicable.

*GHG Emissions Calculation and Monitoring.* For CO<sub>2</sub> emissions from soda ash manufacturing lines, reporters must select one of the following methods, as appropriate:

- For each soda ash manufacturing line with certain types of CEMS in place, reporters must use the CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) to report under the Soda Ash Manufacturing subpart (40 CFR part 98, subpart CC) combined process and combustion CO<sub>2</sub> emissions.

- For other soda ash manufacturing lines, reporters can elect to either (1) install and operate a CEMS and follow Tier 4 methodology to measure and report combined process and combustion CO<sub>2</sub> emissions or (2) calculate CO<sub>2</sub> process emissions using the procedures specified in 40 CFR part 98, subpart CC and summarized below.

- If using approach 2, calculate process CO<sub>2</sub> emissions using one of three alternative methods, as appropriate for each manufacturing line:

- The trona input method calculates the calcination emissions using: Monthly mass of trona input (required to be measured), the average monthly mass-fraction of inorganic carbon in the trona (required to be measured weekly), and the ratio of CO<sub>2</sub> emitted for each ton of trona consumed (a default value is provided).

- The soda ash output method calculates the calcination emissions using: Monthly mass of soda ash produced (required to be measured), the monthly average mass-fraction of inorganic carbon in the soda ash (required to be measured weekly), and the ratio of CO<sub>2</sub> emitted for each ton of soda ash produced (a default value is provided).

- The site-specific emission factor method calculates emissions from production of soda ash using liquid alkaline feedstock through an annual performance test using: The average process vent flow rate from the mine water stripper/evaporator for each manufacturing line, direct measurements of hourly CO<sub>2</sub> concentration, the hourly stack gas volumetric flow rate, the annual process vent flow rate from mine water stripper/evaporator, and annual operating hours.

- Report process CO<sub>2</sub> emissions from each soda ash manufacturing line under 40 CFR part 98, subpart CC (Soda Ash Manufacturing), and report combustion CO<sub>2</sub> emissions from each calciner (kiln) in each manufacturing line under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

**Data Reporting.** In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit

additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart CC.

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

## 2. Summary of Major Changes Since Proposal

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

- A site-specific emission factor method has been added for production of soda ash using liquid alkaline feedstock or mine water. This method was not included in the proposed rule.

- The frequency of inorganic carbon content determination of either trona or soda ash has been revised from daily to monthly based on a weekly composite.
- Procedures were added to 40 CFR 98.295 for estimating missing data for monthly values of inorganic carbon content of trona and monthly values of trona consumption or soda ash production. We also added missing data procedures for parameters specific to calculating emissions from soda ash produced from liquid alkaline feedstock (i.e. site-specific emission factor method).

- 40 CFR 98.296 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.297 to 40 CFR 98.296, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.293 were added to 40 CFR 98.296 for clarity.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Two sets of comments on soda ash manufacturing were received covering several topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart CC: Soda Ash Manufacturing.”

## Method for Calculating GHG Emissions

**Comment:** Both commenters noted that facilities produced soda ash using alternative methods to calcining trona or other carbonate containing minerals. Facilities also produce soda ash from mine water, a liquid alkaline feedstock; this is a “process” emissive production process, but was not addressed in the proposal. The methods in the proposal did not include methods appropriate for calculating process CO<sub>2</sub> from the liquid alkaline feedstock production process. One commenter using this production method recommended that the appropriate method for calculating emissions from this process would be an annual performance test and described the appropriate parameters that would be measured during the annual performance test to establish an emission factor for calculating annual emissions based on concentration of the CO<sub>2</sub> in the evaporated stripped mine water and the annual flow from the mine water stripper/evaporator.

**Response:** We agree that the final rule should address process CO<sub>2</sub> emissions generated from this relatively new alternative production process which produces soda ash from liquid alkaline feedstock or mine water. From additional information provided by the commenter, process CO<sub>2</sub> emissions from this production method are likely to be significant and exceed 25,000 metric tons CO<sub>2</sub>e. This process is currently used by a single company, but could become more widespread within the industry in the future as it makes more efficient use of raw materials previously not used. We have updated all sections of 40 CFR part 98, subpart CC for calculating, monitoring and QA/QC, and reporting of process CO<sub>2</sub> emissions specific to production of soda ash from liquid alkaline feedstock or minewater. We added procedures for developing site-specific emission factor based on an annual performance test consistent with the recommendations provided by the commenter.

**Comment:** One commenter noted that using the total alkalinity of either trona or soda ash as prescribed in Equations CC-2 and CC-3 is inappropriate given that the ratio of carbon dioxide to carbon is a factor in the equations. The equations’ results artificially inflated the CO<sub>2</sub> level by 3.67 times the actual amount.

**Response:** Upon further review, we agree with the commenter’s analysis that the ratio 44/12 will overestimate emissions and have removed this fraction, which is the ratio of carbon dioxide to carbon, from Equations CC-2 and CC-3. Equations CC-2 and CC-3

provide results directly for CO<sub>2</sub> therefore it is not necessary to use a conversion factor to convert the carbon to carbon dioxide.

*Comment:* One commenter noted that Equation CC-3 does not address plant inefficiency specific to each manufacturing line. The commenter suggested that an efficiency factor should be added to Equations CC-3 to account for these inefficiencies.

*Response:* The commenter has not suggested an efficiency factor or otherwise provided data with enough specificity to modify the equations and modify the calculation methods as suggested; therefore, we have decided not to add efficiency factors to Equations CC-3.

EPA needs more information to effectively evaluate this comment and update the equations noted, if appropriate. Efficiency factors can relate to a number of factors including combustion and also kiln conditions, which may vary. We need more information to understand how this factor would be derived for each kiln or manufacturing line. The comment was specific to CC-3, and we suggest the use of Equation CC-2 as an alternative calculation method.

#### Monitoring and QA/QC Requirements

*Comment:* One commenter stated that daily sampling of inorganic carbon content of each manufacturing line is an unnecessary and potentially extremely costly requirement. They suggested that instead of daily testing, testing should be completed as a weekly composite analysis which would then be used in calculating the monthly average.

*Response:* We concur that testing of the inorganic carbon content can be done on a weekly schedule and used to calculate a monthly composite without significant loss in accuracy. The weekly composite would still be based on several daily tests. We have updated the monitoring and QA/QC requirements accordingly in the rule under 40 CFR 98.294.

*Comment:* One commenter stated that the prescribed ASTM method, ASTM E359-00(2005), for determining the inorganic carbon content of trona or soda ash describes a manual titration method using a methyl orange endpoint. They stated that procedures that use autotitrators with fixed endpoint titration are commonly used in the soda ash manufacturing industry and should be allowed as an acceptable equivalent alternative.

*Response:* We agree that methods using autotitration to determine inorganic carbon content of trona or soda ash expressed as total alkalinity are

acceptable equivalent methods for determining the inorganic carbon content of trona or soda ash. We understand that manual titration offers good levels of accuracy but are labor and time intensive. From our understanding, autotitration methods provide comparable or improved levels of accuracy and are less labor and time intensive by "automating" the analysis process. Autotitration methods could provide more consistency in results across the industry. We have updated the procedures in 40 CFR 98.294 for monitoring and QA/QC in the rule to allow for such comparable methods.

#### DD. Sulfur Hexafluoride (SF<sub>6</sub>) From Electrical Equipment

At this time EPA is not going final with the electrical equipment subpart. As we consider next steps, we will be reviewing the public comments and the relevant information.

Based on careful review of comments received on the preamble, rule, and TSDs under 40 CFR part 98, subpart DD, EPA will perform additional analysis and evaluate a range of data collection procedures and methodologies. EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden. In addition, EPA will further evaluate the scope of coverage of electric power systems and the reporting boundaries in other subparts.

#### EE. Titanium Dioxide Production

##### 1. Summary of the Final Rule

*Source Category Definition.* The titanium dioxide production source category consists of any facility that uses the chloride process to produce titanium dioxide.

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

*GHGs to Report.* For titanium dioxide production, report CO<sub>2</sub> process emissions from each chloride process line.

In addition, report GHG emissions for other source categories for which calculation methods are provided in the rule, as applicable. For example, facilities must report CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

*GHG Emissions Calculation and Monitoring.* Reporters must calculate CO<sub>2</sub> process emissions using one of two methods, as appropriate:

- Most reporters can elect to calculate and report process CO<sub>2</sub> emissions from

titanium dioxide process lines by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures specified below.

- However, if process CO<sub>2</sub> emissions from titanium dioxide production are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO<sub>2</sub> emissions, then the reporter must use the CEMS to measure and report combined CO<sub>2</sub> emissions from that stack instead of using the calculation procedures described below.

- If using approach #2, calculate the process CO<sub>2</sub> emissions using the equation provided 40 CFR part 98, subpart EE and monthly determination of the mass and carbon content of calcined petroleum coke consumed in each line and all lines combined. Determine petroleum coke consumption by either direct measurement or purchase records. Determine carbon content of petroleum coke using supplier data or measurement using appropriate test methods. If applicable, also determine the quantity of carbon containing waste generated and its carbon contents using direct measurement.

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

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

##### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart EE: Titanium Dioxide Production."

- Requirements were added for reporting of carbon-containing waste generated from less than 100 percent oxidation of coke during the titanium production process. 40 CFR 98.316

allows for reporting of quantity of carbon-containing waste generated and associated carbon contents.

- Missing data procedures were added under 40 CFR 98.315 for monthly parameters used to calculate emissions, including mass of calcined petroleum coke, mass of carbon-containing waste, and carbon contents of calcined petroleum coke.

- 40 CFR 98.316 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.317 to 40 CFR 98.316, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.313 were added to 40 CFR 98.316 for clarity.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. We received three sets of comments on titanium dioxide production covering several topics. Several of these comments were directed at the requirements for General Stationary Fuel Combustion Sources in subpart C, and responses to those comments are provided in the preamble section dealing with that source category. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart EE: Titanium Dioxide Production.”

#### Method for Calculating GHG Emissions

*Comment:* One commenter noted that the carbon oxidation factor for calcined petroleum coke is not always 100 percent. They point out that the calcined petroleum coke comes with impurities, and a certain amount of the calcined coke is returned to the ground as landfill along with components such as the un-converted TiO<sub>2</sub>. Thus, they suggest that EPA should revise the carbon oxidation factor to allow facilities to use the most appropriate factor for their process, with supporting documentation of its derivation available for EPA review as needed.

*Response:* EPA has considered the comment but maintains the assumption of 100 percent oxidation across all sectors in the final rule. Data reporting requirements have been added to 40 CFR 98.316 to collect information on the quantity of carbon-containing waste generated that is landfilled and its carbon contents which are not emitted. This information will help inform future methods for calculating process emissions from titanium dioxide production (e.g., how to address oxidation rates). EPA interpreted that

this comment may also be applicable to carbon content of calcined petroleum coke. EPA agrees that carbon content may not always be 100 percent and therefore has revised the rule to allow facilities to use supplier data or determine carbon contents using appropriate test methods as part of calculating emissions in 40 CFR 98.313.

#### Procedures for Estimating Missing Data

*Comment:* Two commenters noted there can be numerous reasons data may not be available, on time, or in the format EPA requires. In cases where a required record is found to be missing or determined to be incorrect, the commenters requested that EPA should provide a procedure for estimating missing data.

*Response:* We concur that there may be circumstances where data on carbon contents of coke and petroleum coke consumption may be missing. Records could be misplaced or lost. Thus, we have revised the rule and added specific procedures for estimating missing data in 40 CFR 98.315. These procedures are consistent with those allowed across the rule for similar parameters. For example, if a facility is missing data on carbon contents of petroleum coke we allow facilities to allow sources to substitute the missing data with another quality assured parameter, such as the arithmetic average of the carbon contents from the month immediately preceding and the month immediately following the missing data incident.

#### Data Reporting Requirements

*Comment:* All commenters noted they are concerned that the level of information to be reported, which is considered available for public distribution, could put the domestic TiO<sub>2</sub> producers at a disadvantage relative to international producers. The commenters do not believe that CBI provisions briefly outlined in the preamble are adequate to safeguard the proprietary technical and financial positions of titanium dioxide production facilities. The annual production of titanium dioxide, annual amount of petroleum coke consumed, and annual operating hours are considered CBI and are unnecessary to carry out the purposes of this proposed regulation. This data should only be available onsite or offsite (e.g., a centralized location), or as requested for security cleared EPA personnel and their security cleared contractors where a need is demonstrated for the purposes of this inventory.

*Response:* EPA reviewed CBI comments received across the rule (both general and subpart-specific comments)

and our response is discussed in Section II.R of this preamble and in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Legal Issues.”

In addition, see the Section II.N of this preamble for the response on the emissions verification approach. The amount of petroleum coke consumed is necessary to calculate annual process CO<sub>2</sub> emissions. Production capacity and annual production of titanium dioxide are required for EPA to verify annual CO<sub>2</sub> process emissions. These parameters help EPA to determine whether reported emissions are within a reasonable range. EPA concurs that data on operating hours can be retained as a record and does not need to be reported to EPA. It is not a parameter used in calculating process CO<sub>2</sub> emissions. However, operating hours would help to verify any anomalies in reported emissions or supporting parameters related to temporary closures for repairs or maintenance. This data has been moved to recordkeeping requirements in 40 CFR 98.317.

#### FF. Underground Coal Mines

At this time, EPA is not finalizing the Underground Coal Mines Subpart (40 CFR part 98, subpart FF). As EPA considers next steps, we will be reviewing the public comments on the proposal preamble, rule and TSDs for proposed 40 CFR 98 Subpart FF and other relevant information. EPA will perform additional analysis and consider alternatives to the monitoring requirements.

#### GG. Zinc Production

##### 1. Summary of the Final Rule

*Source Category Definition.* Zinc production facilities consist of zinc smelters and secondary zinc recycling facilities.

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

*GHGs to Report.* For zinc production, report the following:

- CO<sub>2</sub> process emissions from each Waelz kiln and electrothermic furnace used for zinc production.
- CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> combustion emissions from each Waelz kiln and each other stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

In addition, report GHG emissions for other source categories at the facility for which calculation methods are provided in the rule, as applicable.

*GHG Emissions Calculation and Monitoring.* Facilities must calculate CO<sub>2</sub> process emissions using one of two methods, as appropriate:

- Most reporters can elect to calculate and report process CO<sub>2</sub> emissions from each Waelz kiln and electrothermic furnace by either (1) installing and operating CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the calculation procedures specified in the rule.

- However, if process CO<sub>2</sub> emissions from a Waelz kiln or electrothermic furnace are emitted through the same stack as a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO<sub>2</sub> emissions, then the CEMS must be used to measure and report combined CO<sub>2</sub> emissions from that stack, instead of the calculation procedure described below.

- If using approach #2, calculate process CO<sub>2</sub> emissions by determining on an annual basis the total mass (metric tons) of carbon-containing input materials (i.e., zinc-bearing material, flux, electrodes, and any other carbonaceous materials) introduced into each kiln and furnace and the carbon content of each material. Determine carbon content annually either by using supplier data, or by direct measurement using appropriate test methods.

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

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

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these changes can be found below.

- The carbon input method was revised to require an annual analysis of all process inputs and outputs for carbon content rather than monthly sampling and monthly analysis.
- A *de minimis* was added to exclude accounting for carbon-containing

materials contributing less than one percent of the total carbon into Waelz kiln or electrothermic furnaces. These materials do not need to be included in carbon mass balance calculations.

- 40 CFR 98.336 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.337 to 40 CFR 98.336, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.333 were added to 40 CFR 98.336 for clarity.

## 3. Summary of Comments and Responses

No comments specific to regulation of the zinc production sector were received. We revised the frequency of sampling and analysis of carbon contents for carbon containing input materials from monthly to annual consistent with revisions made in response to comments for similar production processes (e.g., emissions from metal production, see the preamble Section III.Q for iron and steel for specific responses to comments). These revisions reduce the reporting burden for zinc production facilities. We understand that the carbon content of material inputs does not vary widely at a given facility for the significant process inputs that contain carbon, and we continue to account for variations due to changes in production rate, which is likely a more significant source of variability.

### HH. Municipal Solid Waste Landfills

#### 1. Summary of the Final Rule

*Source Category Definition.* This source category consists of municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980. The source category includes the MSW landfill, landfill gas collection systems, and landfill gas destruction devices (including flares) at the landfill.

This source category does not include hazardous waste, construction and demolition, or industrial landfills.

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

*GHGs to Report.* For MSW landfills, report the following:

- Annual CH<sub>4</sub> generation and CH<sub>4</sub> emissions from the landfill.
- Annual CH<sub>4</sub> destruction (for landfills with gas collection and control systems).
- Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from stationary fuel combustion devices under 40 CFR part

98, subpart C (General Stationary Combustion Sources).

*GHG Emissions Calculation and Monitoring.* All facilities must calculate modeled annual CH<sub>4</sub> generation based on:

- Measured or estimated values of historic annual waste disposal quantities; and
- Appropriate values for model inputs (i.e., degradable organic carbon fraction in the waste, CH<sub>4</sub> generation rate constant). Default parameter values are specified for bulk municipal waste and individual waste categories.

Facilities that do not collect and destroy landfill gas must adjust the modeled annual CH<sub>4</sub> generation to account for soil oxidation (CH<sub>4</sub> that is converted to CO<sub>2</sub> as it passes through the landfill cover before being emitted) using a default soil oxidation factor. The resulting value must be reported and represents both CH<sub>4</sub> generation and CH<sub>4</sub> emissions.

Facilities that collect and control landfill gas must calculate the annual quantity of CH<sub>4</sub> recovered and destroyed based on either continuous or weekly monitoring of landfill gas flow rate, CH<sub>4</sub> concentration, temperature, and pressure of the collected gas prior to the destruction device.

Those facilities that collect and control landfill gas must then calculate CH<sub>4</sub> emissions in two ways and report both results. Emissions must be calculated by:

1. Subtracting the measured amount of CH<sub>4</sub> recovered from the modeled annual CH<sub>4</sub> generation (with adjustments for soil oxidation using the default value and destruction efficiency of the destruction device) using the equations provided; and

2. Applying a gas collection efficiency to the measured amount of CH<sub>4</sub> recovered to calculate CH<sub>4</sub> generation, then subtracting the measured amount of CH<sub>4</sub> recovered (with adjustments for soil oxidation using the default value and destruction efficiency of the destruction device) using the equations provided. Default collection efficiencies are specified, based on cover material and other factors.

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

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and

summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart HH.

## 2. Summary of Major Changes Since Proposal

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

- Industrial landfills were removed from the applicability provisions of 40 CFR part 98, subpart HH. The applicability provisions were also modified to exempt landfills that did not accept any waste after January 1, 1980.

- Additional methods for estimating quantities of waste for prior (historic) years are provided.

- The requirement to continuously monitor CH<sub>4</sub> composition in the flare gas was removed. If a continuous monitoring system is in place, that data must be used, but weekly sampling of the gas is allowed if such a continuous system is not in place.

- Direct flame ionization methods were added to the rule as an alternative to the gas chromatographic methods for determining methane concentrations. To use a direct flame ionization method, a correction factor must be determined at least once each reporting year and applied to adjust the analyzer's total gaseous organic concentration to an unbiased methane concentration.

- More detailed default values are provided for landfill gas collection efficiencies based on cover material and other factors.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on landfills were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart HH: Landfills."

### Definition of Source Category

*Comment:* Several commenters stated that EPA should limit the applicability of the industrial landfills to landfills located at food processing, pulp and paper, and ethanol production facilities (some also listed petroleum refineries)

because these are the only industries for which landfills were specifically called out. Several commenters noted that impacts were only estimated for pulp and paper and food processing landfills, so EPA should limit the rule to those industries or correct the cost analysis to reflect the true burden of the rule on industrial landfills. Several commenters noted that the reporting requirements seemed tailored for MSW landfills and were generally inappropriate for industrial landfills (truck scales, etc.). One commenter also noted that, if reporting of GHG emissions from industrial landfills is not limited to the food processing, pulp and paper, and ethanol production facilities, then EPA should amend Table HH-1 of 40 CFR part 98, subpart HH and provide specific factors that are relevant to the regulated industry. Several commenters requested that EPA specifically exempt inorganic chemical manufacturing and mining landfills because they do not contain organic waste; other commenters suggested EPA delete requirements for landfills in 40 CFR part 98, subpart Y because landfills are insignificant compared to other sources at a petroleum refinery.

On the other hand, one commenter suggested that EPA may be overlooking an important source of methane emissions by excluding construction and demolition landfills as it seems possible that these landfills receive organic materials such as wood or yard waste that could degrade in an anaerobic environment. This commenter requested EPA provide information on the waste composition of construction and demolition landfills to explain more fully the basis for its decision to categorically exempt these sources from GHG reporting requirements.

*Response:* At this time, EPA is not going final with the industrial landfills proposed requirements of this subpart. In response to the proposal, EPA received numerous detailed public comments on the preamble, rule and TSDs under 40 CFR part 98, subpart HH. Comments addressed the appropriateness, coverage, and methodology for addressing GHG emissions from industrial landfills. In particular, commenters questioned which industrial landfills should be covered by the rule and the need for industry specific factors and methodologies for calculating and reporting emissions. As EPA considers next steps, we will be reviewing the comments and other relevant information and will perform additional analysis and consider alternatives to the proposed monitoring and reporting requirements for industrial landfills.

With regard to construction and demolition landfills, we note that the IPCC 2006 Guidelines for National Greenhouse Gas Inventories estimates that construction and demolition waste has a degradable organic content (DOC) of 0.04 kg/kg waste (see Table 2.5 in Volume 5: Waste), and most of this organic matter is expected to be wood, with slow degradation rates ( $k=0.02 \text{ yr}^{-1}$ ). Based on the anticipated properties of construction and demolition wastes, we anticipated that methane generation at dedicated construction and demolition debris landfills would be small compared to MSW landfills. We will further review these assumptions as we review comments on industrial landfills.

*Comment:* Several commenters stated that the reporting requirements for closed landfills are burdensome, and the rule should be limited to reporting for active landfills. Information on waste disposal quantities and waste composition data are usually not available for closed MSW facilities. Thus, it is impossible to retain or provide the agency with such records for many old landfill sites. Several commenters suggested that EPA should provide additional guidance and screening tools to identify landfills likely to be below the threshold. The commenters noted that small and closed landfills have to collect all of the data needed to report their emissions in order to determine if they are above the reporting threshold.

*Response:* Closed MSW landfills account for approximately half of the nationwide methane emissions from MSW landfills. This is because landfills can continue to emit for decades after they are closed and because these landfills are older, and less likely to have been required to add landfill gas collection systems. However, we do agree that we can remove reporting requirements for a subset of closed landfills to lessen the burden on long-closed landfill facilities. We evaluated the various landfill characteristics and identified that a 30-year waste-in-place (i.e., the total quantity of waste added to the landfill in the past 30 years) provided the best correlation of the data to sites that account for the majority of the contribution to the nationwide GHG emissions from landfills (see memorandum entitled "Correlations with Landfill Methane Generation and Actual Emissions" in the docket EPA-HQ-OAR-2008-0508-2165). Providing an applicability date for closed landfills is essential to minimize the burden associated with obtaining data on old landfills that provide only a small contribution to the nationwide GHG

emissions for landfills, and landfills closed prior to 1980 would not be relevant for the purposes of policy analyses. Therefore, the final rule excludes MSW landfills that have not accepted waste since January 1, 1980. We have also expanded and clarified options for projecting waste disposal quantities that will help ease the burden associated with calculating emissions from landfills that have closed after 1980. EPA remains committed to providing additional outreach materials, guidelines, and screening tools to help potential reporters determine whether the reporting rule applies to their landfill.

#### Method for Calculating GHG Emissions

*Comment:* Several commenters requested additional guidance on how to determine waste disposal rates for years prior to the first reporting year. One commenter noted that the population method provided in the rule was difficult for many landfills because of contract carriers that may haul waste to different landfills in different years, so that the population served by a landfill can be variable. Several commenters noted that the data needed to estimate waste disposal rates for past years was especially challenging for closed landfills and requested guidance on how to comply with the rule if the necessary data do not exist.

*Response:* EPA acknowledges that the single proposed method of estimating past year disposal rates is limiting and may not provide the most accurate projection of waste disposal rates in all cases. We have provided a number of alternative approaches that could be used to estimate annual waste acceptance rates. These include using the current year's annual waste acceptance rate for all past years of operation (for active landfills) and using the landfill capacity and the operating life of the landfill to calculate an average annual acceptance rate (for active and closed landfills). These methods provide a reasonable estimate of historic disposal quantities based on readily available information, even for older landfills. Furthermore, these alternative methods may be just as appropriate or more appropriate for MSW landfills that do not serve a fixed population area.

*Comment:* A few commenters noted that the Solid Waste Industry for Climate Solution (SWICS) has developed protocols for calculating GHG emissions from landfills [see paper titled, Current MSW Industry Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in

Landfills (July 2007)]. The commenters requested that the SWICS recommended defaults for gas recovery system efficiency, soil oxidation, and flare combustion efficiency be provided in the rule. They also stated that an accurate inventory should account for carbon sequestered in the landfill.

*Response:* We again reviewed the SWICS methods in light of these comments. We agree that the SWICS default recommendations for gas recovery system efficiency (which vary from 60 to 95 percent for different types of soil covers) could provide more refined data than using the default values provided in the rule. Therefore, we have included these cover-specific gas recovery efficiencies (commensurate with the SWICS Protocol) as an alternative to the 75 percent default value for collection efficiency. We have also reviewed the SWICS protocol for soil oxidation, which provides suggested oxidation factors ranging from 0.22 to 0.55 depending on the soil cover type. We have several concerns with these factors. First, the values were calculated using arithmetic means which appear to be biased high due to a few high oxidation factors; the median values were generally significantly lower than the average values suggested. Second, the recommended values included laboratory test values, which always yielded higher oxidation fractions. The percent of methane oxidized at the landfill surface is highly dependent on the velocity of gas flow. While areas of low flow are expected to have significant oxidation, areas of high flow will have little to no oxidation. Landfill gas will generally flow to the surface in fissures and channels that offer the least resistance to flow. Consequently, a significant portion of the landfill gas is likely to exit the landfill in a limited number of areas under much higher flow rates than other locations. These high volume flows will not have significant oxidation. Consequently, field test data tend to show lower oxidation factors than laboratory tests where flow is more uniform. Data for five field studies for clay covers (the predominant soil cover type used in the U.S.) were included in the SWICS report. Four of the five field studies had oxidation factors ranging from 0.08 to 0.21, and the median of all five field studies was 0.14. These data appear to support the default 0.10 oxidation factor as provided in the final rule more than they do the 0.22 oxidation factor suggested by SWICS. We will continue to assess the available data to improve soil oxidation estimates; however, we maintain that the use of

the 10 percent default rate is appropriate for this final rule, and clarify that the site-specific oxidation factors (based on the SWICS method or other method) are not to be used. We also find that the SWICS Protocol recommended flare efficiency of 99.996 percent appears unreasonably high. The combustion efficiency of flares is very difficult to assess and may be affected by wind speed and other variables that are not under the direct control of the landfill owner and operator. Consequently, we retained the proposed flare efficiency default. Finally, with respect to the suggested sequestration factors, since collecting data on carbon sequestration is not the purpose of this rule, we do not require facilities to calculate or report carbon storage in landfills.

#### Monitoring and QA/QC Requirements

*Comment:* Several commenters stated that EPA's proposal to require landfills with gas collection systems to continuously measure the methane flow and concentration at the flare or energy device is financially burdensome. According to commenters, the capital costs as well as operation and maintenance costs of a continuous composition analyzer are prohibitive for many facilities, and EPA underestimated the number of facilities that would have to install the required monitors. The commenters also stated that the composition of landfill gas is not highly variable, so less frequent monitoring is justified. One commenter noted that the standard operating procedure at many landfills with gas collection systems is to collect monthly CH<sub>4</sub> flow, and concentration data at the flare. Another commenter recommended that MSW landfills be allowed to calculate quarterly, by means of engineering formulae and/or modeling, the amount of methane present at the flare or energy device. The commenter further noted that, in many cases, it is not practical or even possible for the MSW facility to measure the amount of methane or even landfill gas at the energy device because this device is not owned, operated, or controlled by the facility. Several commenters also requested that EPA allow direct flame ionization analyzers in addition to the gas chromatography methods provided in the proposed rule.

On the other hand, several commenters suggested that EPA should allow, require, or otherwise move towards direct measurement methodologies for characterizing landfill emissions.

*Response:* Methane composition of landfill gas can be expected to vary

based on extreme barometric changes, rainfall event, etc. We expect diurnal variations as well (although not to the same extent as seasonal variations). We also expect variations if the gas collection system has a variable speed fan and the fan speed is adjusted. The commenters provided no data to support the claim that the anticipated fluctuations are not significant enough to warrant continuous monitoring. At proposal, we required continuous flow and composition monitors to improve the accuracy of the emissions estimate. However, after additional uncertainty analysis, we determined that the cost of continuous monitoring systems is not justified in relation to the relatively small improvement in certainty over somewhat less frequent monitoring, i.e. weekly. We do require landfill gas collection systems already equipped with continuous monitoring systems to determine daily average flow and concentrations and to use these data in their gas recovery calculations. For collection systems that do not have continuous gas monitors, weekly sampling is required. Weekly monitoring provides an adequate number of samples to evaluate the variability and uncertainty associated with methane generation. We did not select monthly monitoring because monthly monitoring would result in greater uncertainty and would not significantly reduce the costs compared to weekly monitoring.

We did provide for direct flame ionization analyzers to be used as an alternative to the gas chromatography methods provided in the proposed rule. This alternative reduces the burden on landfills that do not have existing gas chromatography equipment. However, direct flame ionization analyzers will measure both methane and non-methane organic compounds and, as such, will tend to overstate the methane concentration in the landfill gas and provide a high bias to the amount of methane recovered. To eliminate this bias, we also required a correction factor that must be determined at least annually, to arrive at the ratio of the methane concentration to the direct flame ionization analyzer response (calibrated with methane). Including this alternative method with the correction factor reduces the burden on landfills, but still ensures that the calculated methane recovery quantities are unbiased and comparable to the recovery quantities calculated when gas chromatographic methods are used to speciate methane specifically.

With respect to direct measurement methods, we find that direct soil measurements have high uncertainties

due to heterogeneity of the landfill and cover soils and are, therefore, less desirable than the methods provided in the rule (cost more and have higher uncertainty). Optical sensing methods, while potentially more accurate, are very expensive. If measurements were done for only a one-time performance test, the measured emissions would have rather high uncertainties due to variations in temperature and atmospheric pressure. If the measurements were conducted more often, they would be prohibitively expensive. At this time, we cannot justify requiring these types of monitoring systems for this rule. Furthermore, we find that the monitoring requirements in the final rule provide for accurate emission estimates at a reasonable cost burden to reporters.

#### II. Wastewater Treatment

At this time, EPA is not going final with the wastewater treatment subpart (40 CFR part 98, subpart II). As EPA considers next steps, we will be reviewing the public comments and other relevant information. Please note, as originally proposed for this rule, centralized domestic wastewater treatment plants continue to be excluded.

The Agency received a number of comments regarding the applicability of this subpart as well as clarification of the definition of anaerobic wastewater treatment processes. In addition, commenters requested that EPA consider a *de minimus* exemption for emissions from wastewater treatment. The Agency also received a number of comments requesting redefinition of the monitoring requirements for this subpart.

Based on careful review of comments received on the preamble, rule and TSDs under proposed 40 CFR part 98, subpart II, EPA will consider alternatives to data collection procedures and methodologies and examine additional study results that have been released since the proposal was issued. Specifically, EPA will consider requirements for the location of meters for taking flow measurements, the frequency of flow and chemical oxygen demand (COD) measurements taken, as well as the potential use of alternate parameters, such as BOD. EPA will also consider the inclusion of indirect or non-methane volatile organic compound emissions. Lastly, EPA will consider the acceptable methods for estimating missing data. EPA will consider optimal methods of data collection in order to maximize data

accuracy, while considering industry burden.

#### JJ. Manure Management

##### 1. Summary of the Final Rule

*Source Category Definition.* A livestock facility that emits 25,000 metric tons CO<sub>2</sub>e or more per year from manure management systems must report. A facility with an average annual animal population below those listed in Table JJ-1 of 40 CFR part 98, subpart JJ, does not need to calculate emissions or report. A facility with an average annual animal population that exceeds those listed in Table JJ-1 should conduct a more thorough analysis to determine applicability. Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) are estimated by performing an animal inventory or review of facility records. Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) are estimated using the average number of days each animal is kept at the facility and the number of animals produced annually. The rule also contains procedures for facilities with more than one animal group present (e.g., swine and poultry) to determine if they must report.

A manure management system stabilizes or stores livestock manure, or does both, in one or more of the following system components:

- Uncovered anaerobic lagoons.
- Liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks).
- Storage pits.
- Digesters, including covered anaerobic lagoons.
- Solid manure storage.
- Drylots, including feedlots.
- High-rise houses for poultry production (poultry without litter).
- Poultry production with litter.
- Deep bedding systems for cattle and swine.
- Manure composting.
- Aerobic treatment.

GHG emissions from sources at livestock facilities unrelated to the stabilization and/or storage of manure are not covered under this rule and are not reported. Sources considered to be unrelated to the stabilization and/or storage of manure include daily spread or pasture/range/paddock systems or land application activities or other methods of manure utilization not listed above. In addition, manure management activities located off site from a livestock operation are not included in this rule. These off site activities include but are not limited to off site

land application of manure, other off site methods of manure utilization, or off site manure composting operations.

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

*GHGs to Report.* For all livestock facilities with a manure management system that meets or exceeds the reporting threshold, the facility must report aggregate CH<sub>4</sub> and N<sub>2</sub>O emissions from the system components listed above. For those manure management systems that include digesters, CH<sub>4</sub> generated and destroyed, as well as any CH<sub>4</sub> leakage, at the digester must also be reported.

A facility that is subject to this rule only because of emissions from manure management systems is not required to report emissions under 40 CFR part 98 subparts C through PP other than subpart JJ.

*GHG Emissions Calculation and Monitoring.* Detailed methods for calculating GHG emissions are included in the rule and are briefly described below. For each manure management system component other than digesters, facilities must calculate emissions using the following inputs and data:

- Type of system component.
- Average annual animal population (by animal type) contributing manure to the manure management system component.
- Typical animal mass (for each animal type).
- Fraction of manure by weight for each animal type managed in each system component (assumed to be equal to the fraction of volatile solids/nitrogen handled in each system component).
- Volatile solids excretion rates provided in look-up tables for the animal populations contributing manure to the manure management system component.
- Maximum CH<sub>4</sub>-producing potential of the managed manure and CH<sub>4</sub> conversion factors provided in look-up tables for the animal populations contributing manure to the manure management system component.
- Methane conversion factor used (for each manure management system component).
- Nitrogen excretion rates (by animal type) using values provided in look-up tables for the animal populations contributing manure to the manure management system component.
- N<sub>2</sub>O emission factors (by animal type) provided in look-up tables for the animal populations contributing manure to the manure management system component.

For anaerobic digesters, facilities must calculate CH<sub>4</sub> emissions and the annual mass of CH<sub>4</sub> generated and destroyed based on the following inputs and data:

- Continuous monitoring of CH<sub>4</sub> concentration, flow rate, temperature, and pressure of the digester gas.
- CH<sub>4</sub> destruction efficiency of the destruction device and fugitive (leakage) emissions.
- The CH<sub>4</sub> collection efficiency(ies) used (for each digester).

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

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

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified below. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart JJ: Manure Management."

- To assist facilities in determining if they are subject to this rule, a table has been provided that presents average annual animal population values for specific livestock operations (i.e., beef, dairy, swine, and poultry). Facilities that have average annual animal population values below those shown in the table will not be required to report or complete the calculations to determine whether they need to report.

- Since proposal, the requirements for monthly manure sampling to determine volatile solids (VS) and nitrogen (N) content have been removed. Instead of obtaining VS and N content from manure sampling, facilities must use default VS and N excretion values as provided by EPA in look up tables. The default VS and N excretion values are consistent with the 1990–2008 U.S. GHG inventory for manure management and enteric fermentation. For beef and dairy cows, heifers, and steers, VS and N excretion rates were calculated using the IPCC Tier II methodology, based on the relationship

between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. In response to comments, EPA used the most up-to-date information on U.S. animal diets to calculate these excretion rates. For other animal groups, reference values from ASAE and USDA are used.

- EPA has also adjusted the calculations for CH<sub>4</sub> and N<sub>2</sub>O emissions from manure management systems to account for volatile solids and nitrogen removal through solid separation. If solid separation occurs prior to the manure management system component, facilities must use default removal efficiencies as provided by EPA in look up tables. The default values are consistent with those cited in the "Development Document for the Final Revisions to the National Pollutant Discharge Elimination System Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations" (EPA–821–R–03–001), published in December 2002.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on manure management were received covering numerous topics. Responses to significant comments received can be found in the comment response document for manure management in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart JJ: Manure Management."

*Comment:* A number of commenters supported EPA's decision to include livestock facilities with manure management systems in the proposed rule. These commenters noted that the establishment of a mandatory GHG reporting rule is the next logical step in reducing and mitigating GHG emissions in the U.S., and that manure management is a significant source of GHG emissions in the U.S. that should be addressed.

However, other commenters stated that livestock facilities should not be required to report GHG emissions. These commenters noted that a small number of facilities would be covered by the proposed rule, and these facilities would represent a very small percentage of the total number of livestock facilities in the U.S. which would not provide a large enough set of data to help improve or reduce uncertainties associated with GHG inventories. Several of the commenters stated that manure management is not a major source of GHG emissions in the U.S., and the environmental benefits from the rule

would be minimal compared to the effort required to report emissions.

*Response:* EPA disagrees that the manure management source category be excluded from this rule. Manure management has been determined to be a key source of GHG emissions in the U.S., based on the key source category methodology developed by the Intergovernmental Panel on Climate Change (IPCC). The IPCC identifies key sources as those sources that have significant impacts on the total emissions or emission trends in a country.

While livestock manure GHG emissions represent a relatively small fraction of the total U.S. GHG emissions, these emissions are large in absolute terms. According to the 2009 U.S. GHG Inventory, CH<sub>4</sub> emissions from manure management systems totaled 44 million metric tons CO<sub>2</sub>e, and N<sub>2</sub>O emissions were 14.7 million metric tons CO<sub>2</sub>e in 2007; manure management systems account for 7.5 percent of total anthropogenic CH<sub>4</sub> emissions and 4.7 percent of N<sub>2</sub>O emissions in the U.S.

In addition, the collection of facility level GHG emission data, including the type of manure management systems in operation and the number and types of animals serviced by those systems, will help to inform future climate change policy decisions. While the actual number of facilities reporting will be quite small in comparison to the total number of facilities in the U.S., the data gathered through this effort is valuable. For example, these data will help to improve the understanding of emission rates and actions that facilities take to reduce emissions and may improve the effectiveness and design of voluntary and/or mandatory programs to reduce emissions.

*Comment:* Multiple commenters stated that the monitoring requirements in the proposed rule would be too burdensome and expensive for industry to comply with. These commenters expressed concern that sampling manure for VS and N would require more time and effort and be more expensive than EPA estimated. Multiple commenters suggested that default values such as from the American Society of Agricultural and Biological Engineers (ASABE) be permitted for VS and N instead of measured values to eliminate some of the expense associated with the proposed rule.

In addition, a number of commenters noted that there were some methodological issues associated with the monitoring requirements for VS and N. Multiple commenters noted that the requirements for manure sampling should be clarified.

*Response:* EPA acknowledges these concerns and has removed the manure sampling requirements from the final rule. As discussed earlier, EPA used default values for VS and N excretion from USDA and ASAE for swine and poultry, and has calculated these rates for beef and dairy cows, heifers, and steers using the IPCC Tier II methodology, based on the relationship between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. The use of these animal-specific default values for VS and N will greatly reduce the burden to comply with the reporting rule, while only minimally impacting the estimates of GHG emissions. The variation in sampling techniques from facility to facility when characterizing manure "as excreted" from the various animal populations on the facility (as would have been required by the proposal) would negate the benefit derived from this requirement. EPA considered designing a more complex and rigorous program to ensure consistency in the implementation of a manure sampling program and to ensure that manure samples represented "as excreted" manure (prior to any storage or treatment). However, after reviewing comments, we determined that the expected burden of such a program, in terms of time, effort, and expense, outweighed the merits at this time.

*Comment:* A number of commenters noted that calculation errors caused threshold head numbers to be overestimated, which caused the amount of emissions from these operations and the number of operations that would need to report to be underestimated.

*Response:* To estimate the number of facilities at each threshold, EPA first developed a number of model facilities to represent the manure management systems that are most common on large livestock operations and have the greatest potential to exceed the GHG reporting threshold. Next, EPA used the U.S. GHG inventory methodology for manure management to estimate the numbers of livestock that would need to be present to exceed the threshold for each model livestock operation type. Finally, EPA combined the numbers of livestock required on each model operation to meet the thresholds with U.S. Department of Agriculture (USDA) data on farm sizes to determine how many farms in the United States have the livestock populations required to meet the GHG thresholds for each model livestock operation.

Since proposal, EPA made revisions to the threshold analysis spreadsheet calculations based on information and

data provided by commenters. EPA corrected conversion factors used in the nitrous oxide emission calculations, and corrected spreadsheet cell reference errors along with using updated VS and N values. EPA now estimates that there will be approximately 107 livestock facilities that will need to report under the rule.

*Comment:* Commenters also expressed concerns with the emission calculations. Multiple commenters noted that the maximum methane producing capacity (Bo) values used do not reflect variations in animal diet. Several commenters had concerns about the methodology used to estimate the methane conversion factors. In addition, some commenters suggested that other data sources should be considered, such as the ASABE manure standards.

*Response:* After a thorough review of available information, EPA has determined that the methodologies and data sources used to calculate emissions in this rule represent the best available methods and data. EPA reviewed many protocols and approaches prior to selecting the proposed methodology. EPA's selected methodology for reporting GHG emissions (methane and nitrous oxide) associated with manure management systems is based on EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, as well as the IPCC Guidelines for National Greenhouse Gas Inventories. These methodologies rely on the use of activity data, such as the number of head of livestock, operational characteristics (e.g., physical and chemical characteristics of the manure, type of management system(s)), and climate data, to calculate GHG emissions associated with traditional manure management systems. In addition, the selected methodology for the reporting rule uses measured values for those manure management systems (e.g., anaerobic digesters) that collect and combust biogas.

EPA considered requiring direct measurement of GHG emissions from manure management systems, but rejected this approach due to the extreme expense and complexity of such a measurement program. EPA is promulgating an approach that allows the use of default factors, such as a system emission factor, for certain elements of the calculation, and encourages the use of some site-specific data. The cost of such an approach is significantly lower than a direct measurement program. In addition, this approach is consistent with the methods used in offset programs throughout the world, including the California Climate Action Registry's (CCAR) Manure

Management Project Reporting Protocol. For these offset programs, livestock operations are required to complete calculations that establish their "baseline" emissions (prior to the use of a biogas collection system). These baseline emission calculations use similar emissions calculations and default values as are in EPA's Reporting Rule.

The IPCC guidelines have been established by a recognized panel of experts and underwent significant peer review prior to their adoption. In addition, protocols for offset programs, such as CCAR, have gone through similar public review processes prior to their acceptance and use.

*Comment:* Multiple commenters have requested more detailed look up tables and a tool to provide more clarity on which facilities are required to report under the final rule.

*Response:* EPA agrees that additional tables and tools would facilitate compliance with the rule and ease the burden associated with reporting. In response to the comments, EPA has added a threshold table to the final rule (Table JJ-1) to help livestock facilities with manure management systems better determine if they might be subject to the requirements of the rule. EPA also intends to develop applicability tools that can assist facilities that could be covered by the rule, based on table JJ-1 in 450 CFR part 98, subpart JJ, in conducting a more detailed evaluation. These tools will include detailed look-up tables showing the estimated livestock head numbers that would be necessary in order to meet or exceed the threshold and a calculation tool to assist in performing the calculations in the proposed rule.

#### KK. Suppliers of Coal

At this time, EPA is not going final with a subpart for suppliers of coal. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

The Agency received a number of lengthy, detailed comments regarding the coal suppliers subpart. Commenters generally opposed the proposed reporting requirements and raised multiple issues with EPA's legal authority for requiring coal suppliers to report CO<sub>2</sub> emissions. Several commenters stated that reporting by coal suppliers would represent a duplication of the reporting by coal users. For example, electric utilities and industrial plants, which consume the vast majority of coal supplied, are already required to report data on emissions based on their coal purchases. Commenters also stated that the

reporting requirement would entail significant burden and capital costs to coal suppliers. In most cases, commenters provided alternative approaches to the reporting requirements proposed by EPA. For example, commenters suggested that EPA exempt from reporting coal mines that supply coal to mine-mouth power plants, modify the required coal weighing and sampling standards, and eliminate the required statistical correlation between HHV and carbon content.

Commenters raised other issues regarding the reporting of data such as concerns that coal suppliers and laboratories could not realistically purchase and install new coal testing and sampling equipment and provide training to meet the requirements of the proposed rule.

Based on careful review of comments received on the preamble, rule and TSDs under proposed 40 CFR part 98, subpart KK, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies. These alternatives will provide coverage of coal supplied, imported, or exported while concurrently taking into account industry burden.

#### LL. Suppliers of Coal-Based Liquid Fuels

##### 1. Summary of the Final Rule

*Source Category Definition.* This source category consists of producers, importers, and exporters of products listed in Table MM-1 of 40 CFR part 98, subpart MM that are coal-based (coal-to-liquid products). A producer of coal-to-liquid products is any owner or operator who converts coal into liquid products (e.g., gasoline, diesel) using the Fischer-Tropsch or an alternative process.

Suppliers of coal-to-liquid products that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions.

*GHGs to Report.* Suppliers of coal-to-liquid products must report the CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the coal-to-liquid products.

Suppliers of coal-to-liquid products are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH<sub>4</sub> or N<sub>2</sub>O.

*GHG Emissions Calculation and Monitoring.* For each type of coal-to-liquid product, suppliers must calculate CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of

the coal-to-liquid products by following the procedures in 40 CFR 98.393.

*Data Reporting.* In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate GHG emissions that would result from the complete combustion or oxidation of their products. A list of the specific data to be reported for this source category is contained in 40 CFR 98.386.

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate GHG emissions that would result from the complete combustion or oxidation of their products. A list of specific records that must be retained for this source category is included in 40 CFR 98.387.

#### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below.

- We replaced the procedures and calculations proposed in 40 CFR part 98, subpart LL with references to the 40 CFR part 98, subpart MM procedures and calculations. As a result of considerable comment and EPA analysis, 40 CFR part 98, subpart MM procedures and calculations were significantly updated. Since the procedures and calculations necessary for sampling, testing, and measuring coal-to-liquid products are intrinsically linked to the procedures and calculations used for petroleum products, we concluded that referencing 40 CFR part 98, subpart MM in 40 CFR part 98, subpart LL would achieve consistency and completeness.

- We reorganized and updated 40 CFR 98.386 by mirroring 40 CFR 98.396 in order to reflect the updates we made to procedures and calculations and to assist in EPA data verification.

#### 3. Summary of Comments and Responses

EPA did not receive any specific comments on proposed 40 CFR part 98, subpart LL (suppliers of coal-based liquid fuels). Changes made to this subpart were implemented to ensure consistency with changes made to 40 CFR part 98, subpart MM based on public comments provided and EPA analysis conducted.

*MM. Suppliers of Petroleum Products*

## 1. Summary of the Final Rule

*Source Category Definition.* Suppliers of petroleum products consist of:

- *Petroleum refineries* that produce petroleum products through distillation of crude oil.

- *Importers* who satisfy the same meaning given in 40 CFR 98.6, including any entity that imports petroleum products or NGLs as listed in Table MM-1 of 40 CFR part 98, subpart MM. Any blender or refiner of refined or semi-refined petroleum products shall be considered an importer if it otherwise satisfies the aforementioned definition.

- *Exporters* who satisfy the same meaning given in 40 CFR 98.6, including any entity that exports petroleum products or NGLs as listed in Table MM-1 of 40 CFR part 98, subpart MM. Any blender or refiner of refined or semi-refined petroleum products shall be considered an exporter if it otherwise satisfies the aforementioned definition.

Suppliers of petroleum products that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report GHG emissions that would result from the complete combustion or oxidation of the product(s) they supply.

*GHGs to Report.* Suppliers of petroleum products must report annually:

- CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year.

- CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks at a refinery.

Suppliers of petroleum products are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH<sub>4</sub> or N<sub>2</sub>O.

*GHG Emissions Calculation and Monitoring.* Suppliers of petroleum products must choose one of two methods to calculate CO<sub>2</sub> emissions that would result from the combustion or oxidation of each petroleum product and natural gas liquid:

- Method 1: Use the default CO<sub>2</sub> emission factors provided in the regulations for a given petroleum product or NGL; or

- Method 2: Develop an emission factor for a given petroleum product or natural gas liquid using direct

measurements of density and carbon share.

To calculate CO<sub>2</sub> emissions that would result from the combustion or oxidation of biomass co-processed with petroleum feedstock, reporters must use a CO<sub>2</sub> emission factor that is provided in the regulations for each type of biomass.

In calculating total CO<sub>2</sub> emissions that would result from the combustion or oxidation of all petroleum products and natural gas liquids that leave the refinery, refineries must subtract the emissions from petroleum products and natural gas liquids that enter the refinery to be further refined or used on site as well as biomass and biomass-based fuels that are co-processed or blended with petroleum feedstocks.

*Data Reporting.* In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data used to calculate GHG emissions that would result from the complete combustion or oxidation of the product(s) supplied as well as information on the characteristics of crude oil used at a refinery. The specific list of data to be reported for this source category is contained in 40 CFR part 98.396 and includes information to support the data verification process.

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to determine the quantities and characteristics of product(s) reported under this subpart and to calculate GHG emissions that would result from the complete combustion or oxidation of the product(s) supplied. A list of specific records that must be retained for this source category is included in 40 CFR part 98.387.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart MM: Suppliers of Petroleum Products."

- We established a reporting threshold for importers and exporters of 25,000 metric tons of CO<sub>2</sub> per year.

- We changed the source category definition of petroleum refinery for the purposes of 40 CFR part 98, subpart MM to only include facilities that process crude oil. As such, we are not requiring

reporting from facilities that only handle intermediary petroleum products.

- We refined the definition of importers and exporters of petroleum products to clarify reporting requirements for blenders.

- We are not requiring reporters to rely on an exclusive list of standard methods for the measurement of the quantity of products or the calibration and recalibration of equipment. Instead, reporters must use an appropriate standard method published by a consensus-based standards organization. If no such standard exists, reporters are allowed to rely on industry standard practices.

- We provide more flexibility in the frequency of equipment recalibration. Reporters must now comply with the frequency specified by the manufacturer's directions or the selected quantity measurement method.

- We removed the option for reporters to directly measure density but not carbon share under Calculation Method 2. We determined that using a measured density and a default carbon share factor will likely adversely affect the accuracy of the calculated emission factor since the density and carbon share of hydrocarbons are, in the absence of impurities, correlated.

- We are not requiring reporters to rely on an exclusive list of standard methods for sampling products, measuring density, and measuring carbon share under Calculation Method 2. Instead, reporters must use an appropriate standard method published by a consensus-based standards organization.

- We added more specific requirements for the frequency of sampling under Calculation Method 2 and now allow for mathematical composites of samples in addition to physical composites of samples.

- To ensure consistent accounting of denaturant across reporters, we are requiring reporters to assume that 2.5 percent of the volume of any ethanol product that is blended into a petroleum-based product is a petroleum-based denaturant. See below for further explanation.

- For bulk NGLs, reporters must calculate the emissions that would result from the complete combustion or oxidation of the individual components that constitute the NGL (i.e., ethane, propane, butane, isobutane, and pentanes plus).

- We updated the definition of petroleum products to be clear that no petroleum product supplier must report on plastics and plastic products and that

importers and exporters must report on asphalt, road oil, and lubricants.

- We updated the default emissions factors based on technical research since the proposal. We updated certain factors to correct technical errors and to reflect more recent data. We expanded the factors to four significant digits to enhance precision. We also added grade-based sub-categories of finished motor gasoline and blendstocks, combined diesel and fuel oil categories into “distillate fuel” categories, and added sulfur-based subcategories of distillate fuel No. 1 and 2 to better distinguish between product categories with potentially different carbon contents. Full documentation of default emissions factors can be found in the TSD.

- We updated 40 CFR 98.396. First, we made 40 CFR 98.396 more specific, in some cases breaking up one reporting requirement into two for clarity. Second, to allow for EPA verification of reporter calculations, we added reporting requirements for data that a reporter must already use to calculate GHGs as specified in 40 CFR 98.393 through 98.396. Third, after removing the prescriptive list of allowable methods, we added data reporting requirements on the method selected to measure quantity, density, and carbon content and the method selected to sample in order to track the appropriateness of these methods.

We require reporters to assume that ethanol contains 2.5 percent petroleum-based denaturant because we want to ensure that reporters account for the CO<sub>2</sub> emissions that would result from the combustion or oxidation of the denaturant. All ethanol that is blended with petroleum products reported in 40 CFR part 98, subpart MM should contain more than 1.96 percent petroleum-based denaturant by volume, per the requirements in 27 CFR Parts 20 and 21 to make ethanol non-potable. We considered relying on reporters to estimate the percent volume of denaturant in their products, but we determined that, in many cases, reporters would not know this information. We have concluded that 2.5 percent is a suitable assumption for the level of denaturant since, according to an Internal Revenue Service interpretation of Section 15332 in the Food, Conservation, and Energy Act of 2008 in notice 2009–06, ethanol containing greater than 2.5 percent denaturant by volume would not be eligible for the full value of the Volumetric Ethanol Excise Tax Credit. There may be cases where ethanol containing less than 2.5 percent denaturant is blended with petroleum-

based products, but we concluded that it is better to conservatively account for potential petroleum-based carbon emissions rather than arbitrarily pick a number between 1.96 percent and 2.5 percent.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of petroleum products were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart MM: Suppliers of Petroleum Products.”

#### Selection of Threshold

*Comment:* In the proposed rule, EPA sought comment on whether or not to establish a *de minimis* level of imported and exported petroleum products, either in terms of the quantity of products or the CO<sub>2</sub> emissions associated with the combustion or oxidation of products, to eliminate any reporting burden for parties that may import or export a small amount of petroleum products on an annual basis. In response, EPA received several comments in support of establishing some type of *de minimis* value, including a threshold of 25,000 metric tons of CO<sub>2</sub> from the complete combustion or oxidation of all products from individual importers and exporters. EPA also received at least one comment in support of establishing a threshold value for refineries reporting under 40 CFR part 98, subpart MM.

*Response:* In today’s rule, we are establishing a threshold of 25,000 metric tons of CO<sub>2</sub> per year for importers and exporters of petroleum products and natural gas liquids; the threshold is based on a calculation of CO<sub>2</sub> emissions that would result from complete combustion or oxidation of the imported or exported petroleum products and natural gas liquids.

When we conducted the threshold analysis for the proposed rule, we estimated from EIA data that 224 companies would be covered in 40 CFR part 98, MM as importers. Through this analysis, we found that at a threshold of 25,000 metric tons CO<sub>2</sub> per year, 175 importers and 99.9 percent of total emissions that would result from the combustion or oxidation of imported products would be covered by the proposed rule. Therefore, establishing a 25,000 metric ton CO<sub>2</sub> threshold would drop 49 reporters in exchange for a 0.1 percent drop in total emissions. Nonetheless, we decided to propose reporting for all importers because we

felt the reporting burden would be minimal since importers already report the product quantity data to other Federal agencies.

Since proposing the rule, EPA has learned new information, through comments and research, about importers that could be covered as reporters under 40 CFR part 98, Subpart MM. EPA may have omitted some importers of small volumes of petroleum products or natural gas liquids from our original threshold analysis, due to lack of public data. We never intended to cover such small volume imports with this rule (e.g., importers of non-fossil fuel products that contain small quantities of petroleum or natural gas liquids, such as butane lighters). Therefore, for the final rule, EPA concludes that establishing a 25,000 metric ton CO<sub>2</sub> threshold for importers will relieve burden on importers of insignificant quantities of petroleum products and natural gas liquids that we never intended to cover with this rule without significantly diminishing the amount of information received by the agency. In addition, a 25,000 metric ton CO<sub>2</sub> threshold is consistent with other upstream fuel and industrial gas supplier thresholds for importers and exporters in today’s rule.

When we conducted the threshold analysis for the proposed rule, we could not estimate the number of exporting companies that would be covered in 40 CFR part 98, subpart MM because the necessary data was not publically available. Nonetheless, we decided to propose reporting for all exporters because we concluded that the reporting burden would be minimal given the type of information that exporters must maintain as part of their normal business operations.

Since proposing the rule, based on analogous information learned on importers, EPA has concluded that some exporters of very small volumes of petroleum products or natural gas liquids could be covered as reporters under 40 CFR part 98, subpart MM. We never intended to cover such small volume exporters with this rule (e.g., exporters of non-fossil fuel products that contain small quantities of petroleum or natural gas liquids, such as butane lighters). Therefore, for the final rule, EPA has concluded that establishing a threshold for exporters will relieve burden on exporters of insignificant quantities of petroleum products and natural gas liquids that we never intended to cover with this rule. In today’s rule, we have selected a 25,000 metric ton CO<sub>2</sub> threshold because we conclude that it will not significantly diminish the amount of information received by the agency;

overall, exports of refined and semi-refined products are lower than imports, so the threshold adopted for imports will be adequate for collecting data on exports. In addition, a 25,000 metric ton CO<sub>2</sub> threshold is consistent with other upstream fuel and industrial gas supplier thresholds for importers and exporters in today's rule.

In today's rulemaking, we require all refineries as defined in 40 CFR part 98, subpart MM to report, as was proposed. Our threshold analysis of refineries in the proposed rule indicated that all refineries would be covered even if we were to establish a 100,000 metric ton CO<sub>2</sub> threshold. Furthermore, we have determined that all refineries covered by this subpart are already tracking the necessary data to comply with the reporting requirements so the requirements would not pose an undue burden.

#### Monitoring and QA/QC Requirements

*Comment:* EPA received several comments that the proposed approach to determining product quantity was too prescriptive. These comments indicated that the list of allowable methods and equipment types for determining the quantity of products in the proposed rule was incomplete, would result in significant costs for industry, and could adversely impact the quality of the measurements. Commenters noted that industry uses a much larger and ever-growing number of industry methods and equipment types to determine quantity for purposes of product transfers and financial records, including methods and equipment types used to comply with Internal Revenue Service, Securities and Exchange Commission, and Department of Homeland Security's Bureau of U.S. Customs & Border Protection regulations. Commenters suggested that EPA's ability to develop and maintain a comprehensive list of methods would require considerable resources, since companies and consensus-based standards organizations review quantity measurement methods regularly to ensure consistency with technological changes and advancements. Commenters also suggested that methods may improve over time for certain products as a direct result of this rulemaking.

*Response:* In today's rule, we are addressing these concerns by adopting an approach that recognizes the multitude of appropriate industry standard methods and practices and leaves open the possibility that industry may adopt better methods, equipment, and practices over time to determine quantities of products. EPA is requiring

that petroleum product suppliers use an appropriate standard method developed by a consensus-based standards organization, when such a standard method exists. If no such standard method exists, reporters are allowed to follow industry standard practices. Consensus-based standards organizations include organizations such as 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). Reporters must ensure that all equipment used for measuring quantity is calibrated and periodically recalibrated according to the manufacturer's directions or specifications in the appropriate consensus-based industry standard method.

In order to further EPA's understanding of the methods and equipment that reporters use, and to help us better assess the appropriateness of the standard methods and industry practices that individual reporters select, we are requiring that all petroleum product suppliers report the standard method or industry standard practice they use to measure each distinct product quantity that they report to EPA.

*Comment:* Several commenters recommended that EPA provide more flexible approaches to the direct measurement of carbon share and density under Calculation Method 2. Some noted that the proposed requirement to test samples at the end of the year could negatively impact the integrity and quality of those samples. These commenters suggested that EPA allow reporters to test samples monthly and create a mathematical composite of these test results at the end of the year. Some commenters suggested that EPA develop a mechanism whereby reporters could reduce the frequency of sampling once the reporter demonstrates that the variability in the density and carbon share of the product is sufficiently small, and even eliminate direct measurement requirements and allow reporters to use emissions factors developed in previous years. We also received comments requesting that we expand our list of acceptable carbon share measurement methods.

*Response:* We have incorporated several of the suggestions to increase the flexibility of the Calculation Method 2 approach in today's rule. Reporters are now allowed to test their monthly samples throughout the year and conduct a mathematical composite of

the test results at the end of the year. We have also expanded the list of acceptable sampling, density, and carbon share methods to include any appropriate standard method published by a consensus-based standards organization.

We could not determine an adequate approach for allowing reporters to reduce the sampling frequency of products based on statistical evidence of low variability in the density and carbon share for a given product. We want to capture changes in product characteristics over time and have determined that taking monthly samples of an entire product category would not be overly burdensome. Furthermore, reporters are allowed to use default factors under Calculation Method 1 if they so choose.

#### Data Reporting Requirements

*Comment:* EPA received several comments requesting that we eliminate reporting requirements related to products that have potentially non-emissive uses, including plastics and plastic products, petrochemical feedstocks, petroleum coke sent to landfill, asphalt and road oil, and lubricants and waxes. One commenter questioned the incongruity in reporting requirements proposed for refiners, who would report on all products, and importers and exporters who would not be required to report on asphalt, road oil, lubricants, waxes, plastics, and plastic products.

*Response:* Today's rule requires reporting on products with potentially non-emissive uses. Comprehensive upstream data will provide EPA with a full accounting of the emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids introduced into the economy. Furthermore, comprehensive facility-level data can help us conduct a more robust mass balance assessment for data verification purposes. While we recognize that carbon in some petroleum products, such as asphalt, can remain un-oxidized for long periods, petroleum product supplier cannot always know with certainty whether or not the carbon in their products will be released into the atmosphere. Even asphalt can be burned as fuel or incinerated as waste. In the *Inventory of US Greenhouse Gas Emissions and Sinks*, EPA notes several areas of uncertainty surrounding the fate of carbon in petroleum products including those for which the Inventory assumes a 100 percent storage factor for the purposes of the national inventory (e.g., asphalt roofing, asphalt cement,

and asphalt paving materials). As discussed in the proposal, a comprehensive and rigorous system for tracking the fate of petroleum products that may have non-emissive uses is beyond the scope of this rule, and would require a much more burdensome reporting obligation for petroleum product suppliers and other downstream users of petroleum products and natural gas liquids. The data reported as a result of this rulemaking will allow EPA to conduct further research in the future on the pathways and ultimate fate of products with potential non-emissive uses.

It was never EPA's intention to require reporting on plastics and plastic products, so we made this explicit in the definition of petroleum products as well as our definition of a refinery in 40 CFR part 98, subpart MM, which now excludes any facility (e.g. a plastics manufacturing plant) that does not process crude oil. Any CO<sub>2</sub> emissions that would result from the combustion or oxidation of plastics and plastic products manufactured in the U.S. should already be accounted for when a petroleum product supplier introduces the petrochemical feedstock (e.g., propylene) into the economy.

In response to comments on the incongruity of the reporting burden for refiners compared to importers and exporters, we have reevaluated the list of petroleum products with potentially non-emissive uses that importers and exporters do not have to report. In the proposed rule, this list included asphalt, road oil, lubricants, waxes, plastics, and plastic products. Our rationale for excluding these products for importers and exporters was our assessment that there is a much larger variety of these products entering and leaving the country than is produced at a petroleum refinery. Upon further consideration, however, we have concluded that only waxes, plastics, and plastic products would pose an undue administrative burden on importers and exporters. Waxes, plastics, and plastic products enter and leave the country in wide-ranging forms (e.g., cosmetics, candles, lawn furniture, plastic wear) making it difficult to accurately assess the petroleum-based carbon content of these products. We have concluded that the types of asphalt, road oil, and lubricants imported in and exported from the country is much less variable, and importers already track these products and report the quantities to EIA. We have also established a 25,000 metric ton CO<sub>2</sub> annual reporting threshold for importers and exporters in today's rule, which should reduce the number of reporters and minimize the reporting of

products that are imported or exported in very low quantities. Therefore, we are requiring importers and exporters to report the volume and CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the asphalt, road oil, and lubricants they supply.

In response to comments that collecting data on products with potentially non-emissive uses will overestimate actual emissions released into the atmosphere, EPA has and will continue to characterize CO<sub>2</sub> emissions data reported under 40 CFR part 98, subpart MM as emissions that would result from the complete combustion or oxidation of the reported product(s) and not as actual emissions.

*Comment:* EPA received many comments urging us to leverage data that petroleum product suppliers already report to the Energy Information Administration (EIA) and to follow EIA's data collection procedures and protocols. For example, one commenter urged EPA to require refiners on a facility-level and company-wide basis to report to EPA the same level of information on crude imports and processing that is currently reported to the EIA and to follow a process similar to the one used by the EIA; and another commenter urged us to align our reporting requirements with what the industry is already providing to the EIA. Some commenters, urged EPA to make use of data already reported to EIA or other Federal agencies instead of requiring reporting directly to EPA through this rulemaking. EPA also received comments recommending that EIA reporting remain separate from the reporting requirements of this rule.

*Response:* In the proposed rulemaking, EPA stated that we considered, but did not propose, the option of obtaining data by accessing existing Federal government reporting databases and we sought comment on this decision.

In today's rulemaking, we are requiring reporters to report data directly to EPA. We have determined that in order to collect facility-level data from refineries (and company-level data from importers and exporters) that is consistent with other reporters in this rule, in terms of timing, reporting, and verification procedures, we are not able to rely upon EIA data. In addition, EIA relies on a number of legal authorities to pledge confidentiality to statistical survey respondents for company-level information. Some data are collected with legal authority from the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA), under which reported information must be held in confidence

and must be used for statistical purposes only. Collection of data directly by EPA in a central system will allow EPA to electronically verify and publish the data quickly, to use the information for non-statistical purposes, and to handle confidential business information in accordance with the CAA (see the general provisions preamble for additional discussion on CBI). In today's rulemaking we did not replicate EIA's reporting requirements and methodologies if we did not consider them sufficient to achieve our objective, which is to collect comprehensive and accurate data on the CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of petroleum products introduced into the economy. For example, we provide a comprehensive list in Tables MM-1 and MM-2 of 40 CFR part 98, subpart MM, according to which reporters must categorize their products for reporting under today's rulemaking. This list differs from EIA's list of products, according to which reporters must report to EIA. Some of the products are the same on both lists (e.g., aviation gasoline and kerosene) while some products are classified differently on one list than on the other (i.e., EPA's list breaks reformulated gasoline up by summer and winter varieties while EIA breaks reformulated gasoline up by type of oxygenate blended into it). We crafted EPA's product list carefully and we feel that each category has the potential to have a unique carbon share and/or density. Overall, the items on our list are common products in commerce and are already tracked by refineries, importers, and exporters. Therefore, we estimate that the additional burden to comply with this rule will be minimal.

#### *NN. Suppliers of Natural Gas and Natural Gas Liquids*

##### 1. Summary of the Final Rule

*Source Category Definition.* Suppliers of natural gas and natural gas liquids are:

- NGL fractionators, which are installations that fractionate NGLs into their constituent liquid products: ethane, propane, normal butane, isobutane or pentanes plus for supply to downstream facilities.
- Local natural gas distribution companies (LDCs) that own or operate distribution pipelines that deliver natural gas to end users. Companies that operate interstate pipelines transmission or intrastate transmission pipelines are not part of this source category.

Suppliers of natural gas and NGLs that meet the applicability criteria in the General Provisions (40 CFR 98.2)

summarized in Section II.A of this preamble must report GHG emissions that would result from complete combustion or oxidation of products they supply.

*GHGs to Report.* Natural gas fractionators must report CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the annual quantities of propane, butane, ethane, isobutene, and pentanes plus supplied.

Local distribution companies must report CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the annual volume of natural gas distributed to their customers.

Suppliers of natural gas and NGLs are not required to report data on emissions of other GHGs that would result from the complete combustion or oxidation of their products, such as CH<sub>4</sub> or N<sub>2</sub>O.

*GHG Emissions Calculation and Monitoring.* Reporters must use one of two methods to calculate the CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of natural gas supply or NGL supply:

- One method uses either a measured or default fuel heating value and either a measured or default CO<sub>2</sub> emissions factor. This method is most appropriate for liquid fuels.

- The second method uses either a measured or default CO<sub>2</sub> emissions factor. This method is most appropriate for gaseous fuels.

- A NGL fractionator must then follow two additional equations, if applicable, to subtract the CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of NGL supply that are double-counted. A LDC must then follow up to four additional equations, if applicable, to subtract the CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of natural gas supply that is double-counted.

*Data Reporting.* In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate natural gas or NGL supply. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart NN.

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate natural gas or NGL supply. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart NN.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids."

- We changed the source category responsible for reporting NGL supply in 40 CFR part 98, subpart NN from all natural gas processors to only facilities that fractionate natural gas liquids.

- We eliminated the requirement to report bulk NGL since NGL fractionators do not supply bulk NGL.

- We added equations to calculate emissions that would result from the oxidation or combustion of the following volumes of natural gas and NGLs because they should be subtracted from the reporter's total emissions calculation, when applicable: fractionated NGLs received from other fractionators; natural gas injected for storage; natural gas delivered to individual customers already reporting under another Subpart of this rule; and natural gas delivered by an LDC to another LDC.

- We clarified the points of measurements for reporting purposes.

- We changed the rule to allow local distribution companies to use transmission pipeline metered volumes and calculated heating value where the local distribution companies do not perform their own measurements.

- We provide flexibility in frequency of equipment calibration, requiring reporters to comply with standard industry practices for measurements used for billing purposes as audited under Sarbanes Oxley regulations.

- We added a procedure for measuring the carbon content of blends of NGLs since NGL fractionators may supply blends of NGLs.

- We updated 40 CFR 98.406. First, we made 40 CFR 98.406 more specific, in some cases breaking up one reporting requirement into two for clarity.

- Second, to allow for EPA verification of reporter calculations, we added reporting requirements for data that a reporter must already use to calculate GHGs as specified in 40 CFR 98.403 to 40 CFR 98.406. This includes the addition of reporting requirements for new calculations introduced in the final rule to prevent supply double-counting. Third, after removing the prescriptive list of allowed standards and methods, we added data reporting requirements on the method selected to measure

quantity, HHV, and carbon content.

Fourth, we added a reporting requirement for the quantity of odorized propane. Fifth, we added data reporting requirements for inputs received by a NGL fractionator in order to conduct verification using a mass-balance approach.

## 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of natural gas and NGLs were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids."

### Definition of Source Category

*Comment:* EPA received many comments on the non-emissive use of natural gas liquids (NGLs). In general, these comments stated that NGLs such as ethane, butane, and isobutene, are either used as feedstocks in the petrochemical industry or as blendstocks that are reported by refineries in 40 CFR part 98, subpart MM, and should not be reported as though they are completely combusted or oxidized. Several commenters proposed that odorized propane should be the focus of 40 CFR part 98, subpart NN rather than all NGLs because odorized propane is the only NGL that is combusted as fuel.

*Response:* Today's rule still requires reporting on all NGL products, even those with potentially non-emissive uses. Comprehensive upstream data will provide EPA with a full accounting of the emissions that would result from the complete combustion or oxidation of all natural gas liquids introduced into the economy.

As discussed in the proposal, a comprehensive and rigorous system for tracking the fate of natural gas liquids that may have non-emissive uses is beyond the scope of this rule, and would require a much more burdensome reporting obligation for NGL fractionators and downstream users of natural gas liquids. Based on the data available today, we do not believe that a NGL fractionator can know with certainty whether or not the carbon in their products will be released into the atmosphere. The data reported as a result of this rulemaking will allow EPA to conduct further research on the pathways and ultimate fate of NGL and to refine our understanding of and

policy on products with potential non-emissive uses.

Therefore, EPA does not concur with the proposal to replace NGL reporting with propane odorizers. However, EPA concurs that odorized propane lines up closely with propane combusted downstream, and that data collection on odorized propane would help EPA decide if and how to carry out a wide variety of CAA provisions on emission sources, as authorized broadly under CAA sections 114 and 208. As a result, we have added reporting requirements on the volume of propane odorized on site in today's rule.

We do not concur that products reported under 40 CFR part 98, subpart NN, such as isobutane to be blended with fuel, will be double-counted as products reported under 40 CFR part 98, subpart MM. Subpart MM requires refineries to report all non-crude feedstocks that enter the facility in order to subtract the emissions that would result from the oxidation or combustion of those products from their calculations. Such methodology allows EPA to collect data on the entire petroleum and natural gas liquids system without any double-counting.

Finally, in response to comments that collecting data on products with potentially non-emissive uses will overestimate actual emissions released into the atmosphere, EPA will continue to characterize CO<sub>2</sub> emissions data reported under 40 CFR part 98, subpart NN as emissions that would result from the complete combustion or oxidation of the reported product(s) and not as actual emissions.

*Comment:* Many commenters discouraged EPA from requiring reporting from natural gas processors. In general, these comments stated that processors do not know the constituents of the gas they process. They further stated that since bulk NGLs are often sent from one processor to another, reporting by processors on bulk NGLs would result in double-counting of supply. Ultimately, several commenters were confused by the multiple definitions provided in the rule for a natural gas processor and were not clear on the exact covered party in 40 CFR part 98, subpart NN.

*Response:* In the final rule, we specify the source category as NGL fractionators rather than as natural gas processors, and we have removed the requirement to report bulk NGLs. To avoid any remaining potential for double-counting, we provide an equation for a fractionator to subtract from its calculations any NGL constituents received from other fractionators that

would report those products under this rule.

By requiring reporting from NGL fractionators, we have removed the need for the term "natural gas processor" in 40 CFR part 98, subpart NN. Multiple definitions for this term no longer exist in the rule.

#### Monitoring and QA/QC Requirements

*Comment:* Many commenters interpreted EPA's measurement and calibration requirements differently than we intended, and as a result pressed upon EPA the inability of industry to reasonably meet such requirements. Many commenters interpreted that EPA required meter reading and calibration of every customer meter. Other commenters interpreted that EPA required daily measurement totals of throughput.

*Response:* In today's rule, we provide precise language to remove any confusion about monitoring and QA requirements. First, we clarify that the point of measurement for natural gas supply is the city gate meter. If the LDC makes its own measurements at the city gate according to business as usual practices, then it must use its own measurements. If not, it must use the delivering pipeline invoices measurements. The only exceptions are that the point of measurement for natural gas delivered to large end-users is the customer meter and the point of measurement for natural gas stored or removed from storage is the appropriate storage meter. However, we clarify that customer meters and storage meters are not subject to the 40 CFR part 98, subpart NN calibration requirements.

Second, we clarify that the minimum frequency of the measurements of quantities of NGLs and natural gas shall be based on the reporter's standard practices for commercial operations. For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume. For natural gas the minimum frequency of measurement shall be based on the LDC's standard measurement schedules used for billing purposes and summed to the annual reportable volume. If daily measurements are not standard practice for a reporter, then that reporter need not conduct daily measurements.

EPA clarifies in the final rule that customer meters do not face calibration requirements under 40 CFR part 98, subpart NN. Other equipment used to measure quantities must be calibrated prior to their first use for reporting under this subpart, using a suitable standard test method published by a

consensus based standards organization or according to the equipment manufacturer's directions. Such equipment must also be recalibrated at the frequency specified by the standard test method used or by the manufacturer's directions. EPA has concluded that initial calibration requirements are necessary to ensure consistency across all reporters and accuracy of data. Since such a wide variety of calibration methods is allowed and since commenters stated that industry already calibrates carefully as a result of State Utility Commission and other regulations, EPA concluded that industry is already following such calibration requirements for usual business operations.

#### Data Reporting Requirements

*Comment:* EPA received many comments on the requirement for LDCs to report information on individual customers. In general, commenters interpreted the reason for EPA to collect this data differently than was intended. Many commented on the CBI nature of customer-specific delivery information. Others commented that LDCs do not or may not have access to the EIA or EPA numbers of their customers. One commenter told us that a LDC can only attest to the gas volume delivered through a single particular meter at a single particular location, which is not necessarily an individual customer.

*Response:* In the final rule, EPA has clarified that an LDC must report on customers that receive more than 460,000 million standard cubic feet (Mscf) per year in order to subtract that volume out of its total calculations. EPA's intention is to use this data to remove potential double-counting and to prevent a LDC from calculating and reporting an overstated supply volume. EPA can also use these data to verify that covered direct emitters are approximately reporting under the rule. In response to comments that LDCs do not or may not have access to customers' EIA or EPA numbers, we have changed the reporting of this from required to voluntary, if known. We have further specified that LDCs must report large volumes delivered to a single meter rather than to a particular end-user.

#### OO. Suppliers of Industrial GHGs

##### 1. Summary of the Final Rule

*Source Category Definition.* Suppliers of industrial GHGs consist of the following:

- Facilities producing any fluorinated GHG or N<sub>2</sub>O, except those that produce

only HFC-23 generated as a byproduct during HCFC-22 production.

- Bulk importers of fluorinated GHGs or N<sub>2</sub>O, if the total combined imports of industrial GHGs and CO<sub>2</sub> exceed 25,000 metric tons of CO<sub>2</sub>e per year.

- Bulk exporters of fluorinated GHGs or N<sub>2</sub>O, if the total combined exports of industrial GHGs and CO<sub>2</sub> exceed 25,000 metric tons CO<sub>2</sub>e per year.

Suppliers of Industrial GHGs that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must report industrial GHG supply flows.

*GHGs to Report.* Suppliers of industrial GHGs must report the amount of N<sub>2</sub>O and each fluorinated GHG produced, imported, exported, transformed, or destroyed during the calendar year. Importers and exporters of CO<sub>2</sub> must calculate and report annual amounts of CO<sub>2</sub> according to 40 CFR part 98, subpart PP.

*GHG Emissions Calculation and Monitoring.* Suppliers must use the following methods to calculate annual industrial GHG supply flows:

- The mass of each fluorinated GHG or N<sub>2</sub>O produced must be determined by measurements of gas production, less the mass of that GHG added to the process upstream (e.g., where used GHGs are added back to the production process for reclamation).

- The mass of each fluorinated GHG transformed must be determined considering the mass of fluorinated GHG fed into the transformation process and the efficiency of that process (as indicated by yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted).

- The mass of each fluorinated GHG destroyed must be determined by measurements of the mass of fluorinated GHG fed to the destruction device and a measurement of the destruction efficiency.

*Data Reporting.* In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate industrial GHG supply flows or that can be used to verify industrial gas supply flows. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart OO.

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records

of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart OO.

## 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart OO: Suppliers of Industrial GHGs."

- EPA has elaborated on the definition of "produce" to clarify what it does and does not include. The definition now explicitly includes (1) the manufacture of a fluorinated GHG for use in a process that will result in the transformation of that GHG (either at or outside of the production facility) and (2) the creation of a fluorinated GHG (with the exception of HFC-23) that is captured and shipped off site for any reason, including destruction. The definition now explicitly excludes the creation of by-products that are released or destroyed at the production facility.

- EPA has eased the accuracy and precision requirements for measuring production, transformation, and destruction. EPA is also permitting facilities flexibility in the frequency of measurements and calibration of measurement devices. Masses produced, fed into transformation processes, and fed into destruction devices must now be estimated to a precision and accuracy of one percent rather than 0.2 percent. Requirements to measure concentrations, which had previously been associated with the transformation and destruction provisions, have been changed to requirements to estimate concentrations or related quantities.

- EPA has eliminated the requirement that fluorinated GHG production facilities that destroy fluorinated GHGs annually verify the destruction efficiency of their destruction devices.

- EPA has added an additional method for estimating missing mass flow data in the event that a secondary mass measurement for that stream isn't available. In that event, producers can use a related parameter and the historical relationship between the related parameter and the missing parameter to estimate the flow.

- EPA has removed the option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or under-estimate the data.

- EPA has added some reporting requirements to be consistent with the

changes to the calculations and monitoring sections and to permit verification of emissions calculations.

- EPA has added an exemption from reporting requirements for import or export shipments containing less than 250 metric tons of CO<sub>2</sub>e.

- EPA has clarified that the criteria for imported container heels at paragraph 98.417(e) set forth the conditions under which importers do not need to report heels; they do not establish requirements for all containers containing residual gas. If importers import containers with residual gas that does not meet these conditions, they must simply report these imports under paragraph 98.416(c). In addition, EPA is adding another condition under which imported heels do not need to be reported; that is the case in which the heels are recovered and included in a future shipment.

- EPA is requiring fluorinated GHG production facilities to submit a one-time report describing current measurement and estimation practices.

EPA is requiring the one-time report on measurement practices because the Agency is providing some flexibility to reporters regarding the methods that they use to calculate industrial gas supply flows. This flexibility permits reporters to use a larger range of methods and measurement equipment than were proposed, and it is important for EPA to understand the methods and equipment and their accuracies. Similar reports are required under EPA's Stratospheric Ozone Protection Regulations at 40 CFR part 82.

As noted above, EPA removed the option for reporters to develop their own methods for estimating missing data if they believe that the prescribed method will over- or underestimate the data. EPA removed this option for two reasons. First, the proposed provision lacked clear guidance on when alternative methods should be used (e.g., on the size of an underestimate that would justify use of an alternative method) and on how they should be developed. Second, the proposed provision was redundant with the new provision that permits reporters to estimate missing data using a related parameter and the historical relationship between the related parameter and the missing parameter. This new option provides reporters with flexibility in substituting for missing data in the event that a secondary mass measurement is not available, but sets out general guidance on how to select the substitute data.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of industrial GHGs were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart OO: Suppliers of Industrial GHGs."

#### Definition of Source Category

*Comment:* EPA received a number of comments regarding the proposed definition of "fluorinated greenhouse gas." Several commenters argued that the proposed definition was too broad because it would include nonvolatile materials that could not be emitted to the atmosphere and materials for which GWPs had not been calculated. One commenter suggested establishing a lower vapor pressure limit for fluorinated GHGs (heat transfer fluids) of 400 Pa (0.004 bar, or three mm Hg absolute) at 25 C. Some commenters expressed the concern that the lack of GWPs for some covered compounds would lead to incomplete or inconsistent reporting because facilities would assign their own GWPs to compounds for which GWPs were not provided in Table A-1 of 40 CFR part 98, subpart A.

Some commenters recommended that EPA address these concerns by requiring reporting of only those fluorinated compounds listed in Table A-1 of 40 CFR part 98, subpart A. However, one of these commenters noted that the list in A-1 is incomplete and inconsistent, excluding for example, some high-GWP compounds whose low-GWP alternatives are included. This commenter recommended that EPA establish a "visible and participative process" to add other compounds as appropriate to Table A-1 of 40 CFR part 98, subpart A.

*Response:* In today's final rule, EPA is modifying the proposed definition of fluorinated GHG by adding an exemption for "substances with a vapor pressure of less than one mm of Hg absolute at 25 degrees C." This modification ensures that non-volatile fluorocarbons such as fluoropolymers are excluded from reporting requirements, while requiring reporting of fluorocarbons (as well as SF<sub>6</sub> and NF<sub>3</sub>) that could reasonably be expected to be emitted to the atmosphere.

As noted by several commenters, this definition would require reporting of some fluorocarbons to which GWPs have not been assigned in either IPCC or

World Meteorological Organization (WMO) Scientific Assessments (i.e., fluorocarbons for which Table A-1 of 40 CFR part 98, subpart A does not provide GWPs). However, the lack of GWPs for some fluorocarbons will not impede reporting because EPA is requiring reporting of production and other quantities in tons of chemical rather than in tons of CO<sub>2</sub>e. For purposes of determining whether or not the 25,000 metric ton CO<sub>2</sub>e import or export threshold is exceeded, EPA is requiring facilities to include only substances whose GWPs appear in Table A-1 of 40 CFR part 98, subpart A.

EPA believes that this approach is prudent and appropriate. As acknowledged by commenters, Table A-1 of 40 CFR part 98, subpart A is not a complete listing of current or potential fluorinated GHGs; the IPCC and WMO lists on which it is based reflect only the facts that the listed materials have been synthesized, their atmospheric properties investigated, the results published, and the publications found by the IPCC and WMO Assessment authors. Table A-1 is known to omit some existing fluorinated GHGs and it unavoidably omits future fluorinated GHGs that have not yet been synthesized. Given the radiative properties of the carbon-fluorine bond, any fluorocarbon emitted into the atmosphere may have a significant GWP. This is true even for some fluorocarbons with lifetimes of less than one year, including, for example, HFE-356pcc3, with a lifetime of four months and a 100-year GWP of 110.

Reporting of fluorocarbons that do not appear in Table A-1 of 40 CFR part 98, subpart A will provide valuable information on the full range of volatile fluorocarbons entering U.S. commerce. This information can be used to assess the overall volume and importance of compounds for which GWPs have not been evaluated and to help identify which compounds should have their GWPs evaluated first. In addition, once GWPs have been identified for these compounds, historical reports in tons of chemical can be converted into CO<sub>2</sub>e. Without a comprehensive reporting requirement, such historical information could be lost. Ultimately, all of this information can be used to inform policy decisions regarding the appropriate type and scope of emission reduction measures for these gases. Considering the modest cost of reporting production, import, and export of such compounds, the potential value of this information justifies a comprehensive definition of fluorinated GHG.

EPA agrees with commenters who noted that Table A-1 of 40 CFR part 98,

subpart A should be periodically updated through a visible and participative process. EPA anticipates that as GWPs are evaluated or re-evaluated by the scientific community, the Agency will update Table A-1 of 40 CFR part 98, subpart A through notice and comment rulemaking. EPA may also, through rulemaking, establish a more proactive process for ensuring that GWPs are appropriately evaluated or re-evaluated.

*Comment:* EPA received comments both supporting and opposing a requirement to report imports of fluorinated GHGs contained in equipment and foams. Commenters supporting such a requirement noted that these imports comprised a significant fraction of U.S. consumption of fluorinated GHGs, that excluding these imports from reporting would put domestic manufacturers at a disadvantage and lead to leakage of manufacturing and increased emissions of GHGs, and that the burden of reporting these imports would be low, since there are relatively few importers and the reported information is easily accessible. Commenters opposing such a requirement stated that the benefit of reporting would be small because pre-charged equipment and foams are "hermetically sealed systems that essentially emit no GHGs," while the cost would be high due to the large number of importers.

*Response:* EPA did not propose to require reporting of fluorinated GHGs contained in imported products because EPA was concerned that the administrative burden of such a requirement could be considerable, while the quantities imported in at least some types of products could be small. However, in the proposal EPA acknowledged that the quantities of fluorinated GHGs imported in pre-charged equipment and foams appeared significant, and that ascertaining the identity and quantity of fluorinated GHGs in these products might be relatively straightforward. EPA is continuing to research these issues, and is deferring the final decision on whether to include imports of equipment and foams containing fluorinated GHGs to a later rulemaking.

#### Monitoring and QA/QC Requirements

*Comment:* Several commenters stated that facilities could not meet the proposed accuracy, precision, and frequency requirements for their measurements of production, transformation, and destruction using existing equipment and practices. These commenters stated that they would need to expend significant funds (millions of

dollars in some cases) and time to install Coriolis flowmeters in multiple streams and to implement daily sampling protocols to analyze the contents of these streams. One commenter requested that EPA revise its precision and accuracy requirements to one percent for measurements of mass. Other commenters argued that instead of establishing strict accuracy, precision, and frequency requirements for measuring production, EPA should permit facilities to use existing measurement instruments and practices, such as NIST Handbook 44 and the trial HFC reporting program patterned on EPA's reporting requirements for ozone-depleting substances.

*Response:* Given the limited amount of time before 2010 data collection must begin, EPA agrees that it is appropriate to ease the accuracy and precision requirements proposed for measuring production, transformation, and destruction. EPA is therefore revising these requirements in the final rule. EPA is also permitting facilities flexibility in the frequency of measurements and calibration of measurement devices.

This approach will permit facilities to begin measuring their production, transformation, and destruction for purposes of the rule beginning in January 2010, using their current practices and equipment. However, EPA is planning to revisit the precision and accuracy requirements for industrial gas supply as we review public comments and perform analyses related to proposed 40 CFR part 98, subpart L (fluorinated gas production), which is not included in today's final rule. This is because the accuracy and precision with which production facilities track production, transformation, and destruction can have a profound influence on the accuracy and precision of these facilities' fluorinated GHG emission estimates. For one method of monitoring F-GHG emissions under consideration, a one percent relative error in production mass measurements could result in a much higher relative error in the emissions estimate, e.g., over 90 percent at an emission rate of 1.5 percent. For other methods of monitoring F-GHG emissions, however, a one percent relative error in production mass measurements would not lead to large errors in emission estimates. For both 40 CFR part 98, subpart OO and 40 CFR part 98, subpart L, EPA's goal is to optimize methods of data collection to ensure data accuracy while considering industry burden.

### *PP. Suppliers of Carbon Dioxide (CO<sub>2</sub>)*

#### 1. Summary of the Final Rule

*Source Category Definition.* Under the rule, suppliers of CO<sub>2</sub> consist of the following:

- Facilities with production process units that capture and supply CO<sub>2</sub> for commercial applications or that capture and maintain custody of a CO<sub>2</sub> stream in order to sequester or otherwise inject it underground.
- Facilities with CO<sub>2</sub> production wells that extract a CO<sub>2</sub> stream for the purpose of supplying CO<sub>2</sub> for commercial applications.
- Importers of bulk CO<sub>2</sub>, if total combined imports of CO<sub>2</sub> and other GHGs exceed 25,000 metric tons of CO<sub>2</sub> equivalent (CO<sub>2</sub>e) per year.
- Exporters of bulk CO<sub>2</sub>, if total combined exports of CO<sub>2</sub> and other GHGs exceed 25,000 metric tons CO<sub>2</sub>e per year.

This source category is focused on upstream supply. It does not cover: Storage of CO<sub>2</sub> above ground or in geologic formations; use of CO<sub>2</sub> in enhanced oil and gas recovery; transportation or distribution of CO<sub>2</sub>; or purification, compression, on-site use of CO<sub>2</sub> captured on site, or processing of CO<sub>2</sub>. This source category does not include CO<sub>2</sub> imported or exported in equipment, such as fire extinguishers.

Suppliers of CO<sub>2</sub> that meet the applicability criteria in the General Provisions (40 CFR 98.2) summarized in Section II.A of this preamble must submit GHG reports.

*GHGs to Report.* Suppliers of CO<sub>2</sub> must report the mass of CO<sub>2</sub> in a stream captured from production process units and extracted from production wells, and the mass of CO<sub>2</sub> in containers that is imported and exported.

*GHG Emissions Calculation and Monitoring.* While this source category is focused on upstream supply of CO<sub>2</sub>, EPA recognizes that all CO<sub>2</sub> supplied to the economy does not necessarily result in an emission. There are a variety of downstream applications for CO<sub>2</sub>—some applications are emissive and some are non-emissive. Under this rulemaking, a CO<sub>2</sub> supplier facility must calculate the mass of CO<sub>2</sub> supplied quarterly by measuring the mass or volumetric flow of gas and multiplying by the CO<sub>2</sub> concentration, and density in the case a volumetric flow meter is used, of the gas or liquid, as specified below. EPA requires quarterly monitoring because EPA has concluded that the CO<sub>2</sub> concentration of the stream varies throughout the year, and a quarterly concentration number multiplied by a quarterly volume will generate more accurate calculation of CO<sub>2</sub> supply than

annual measurements. EPA requires these quarterly numbers to be reported so that EPA can electronically verify the calculations. The CO<sub>2</sub> supplier must also provide information on the downstream CO<sub>2</sub> application, if known. Reporters must use the following methodologies, as applicable, for calculating CO<sub>2</sub> supplied:

- For suppliers that make measurements with mass flow meters, calculate quarterly for each meter the total mass of CO<sub>2</sub> in a CO<sub>2</sub> stream in metric tons, prior to any subsequent purification, processing, or compressing, according to Equation PP-1 of 40 CFR 98.423. Measure mass flow and concentration in accordance with 40 CFR 98.424.
- For suppliers that make measurements with volumetric flow meters, calculate quarterly for each meter the total mass of CO<sub>2</sub> in a CO<sub>2</sub> stream in metric tons, prior to any subsequent purification, processing, or compressing, according to Equation PP-2 of 40 CFR 98.423. Measure volumetric flow, concentration and density in accordance with 40 CFR 98.424.
- For suppliers that have multiple flow meters, aggregate data according to methods specified in Equation PP-3 in 40 CFR 98.423.
- Importers or exporters that import or export CO<sub>2</sub> in containers must calculate the total mass of CO<sub>2</sub> supplied in metric tons, prior to any subsequent purification, processing, or compressing, according to equation PP-4 of 40 CFR 98.423. Use weigh bills, scales, or load cells to measure the mass of CO<sub>2</sub> imported or exported in containers.

*Data Reporting.* In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)) and summarized in Section II.A of this preamble, reporters must submit additional data that are used to calculate CO<sub>2</sub> supply. A list of the specific data to be reported for this source category is contained in 40 CFR 98.426.

*Recordkeeping.* In addition to the records required by the General Provisions (40 CFR 98.3(g)) and summarized in Section II.A of this preamble, reporters must keep records of additional data used to calculate CO<sub>2</sub> supply. A list of specific records that must be retained for this source category is included in 40 CFR 98.427.

#### 2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas

Reporting Rule: EPA's Response to Public Comments, Subpart PP: Suppliers of Carbon Dioxide."

- We added equations and QA requirements to allow reporters to determine CO<sub>2</sub> quantity using volumetric flow meters, weigh bills, scales, or load cells, as appropriate. These additions supplement the proposed equations and quality assurance requirements to determine CO<sub>2</sub> quantity using mass flow meters.

- We revised the reporting procedures for missing data in 40 CFR 98.425. Facilities must use quarterly values as substitute data as they can no longer use annual average values. We added missing data procedures to allow for more quarterly data points to be used, as appropriate. EPA concluded that quarterly missing data values will generate more accurate estimates than annual average values.

- To improve the emissions verification process, we reorganized and updated 40 CFR 98.426. We moved some data elements from 40 CFR 98.427 to 40 CFR 98.426, and added some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.423 to 40 CFR 98.426 for clarity.

- We revised the reporting and calculation procedures to require facilities using flow meters to determine annual mass for every flow meter used. To aggregate data at the facility level for CO<sub>2</sub> being captured in production wells or production process units, we have added Equation PP-3.

- To decrease unnecessary sampling burden, we have removed the requirement of quarterly concentration sampling for importers and exporters that use containers of CO<sub>2</sub>.

### 3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on suppliers of CO<sub>2</sub> were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart PP: Suppliers of Carbon Dioxide."

#### Definition of Source Category

*Comment:* EPA received many comments about how we defined the source category in this Subpart. One group of comments stated that the CO<sub>2</sub> supplied to the economy should not be characterized as an emission. Some in this group of comments specified that much of the supplied CO<sub>2</sub> is stored at enhanced oil recovery (EOR) sites, which are "closed systems", rather than

emitted. In general, these same commenters stated that any CO<sub>2</sub> reporting requirements placed by EPA on industry should be placed on downstream CO<sub>2</sub> users, such as EOR facilities, rather than CO<sub>2</sub> suppliers and should be for actual emissions only. Other comments echoed that EPA needs to collect data from recipients of supplied CO<sub>2</sub> such as EOR sites. This group pressed upon EPA the need to collect not only data on actual emissions but also data on injection, production, and geologic sequestration of CO<sub>2</sub>. Some of the benefits cited for collecting such comprehensive data include: Assisting in ensuring no more than negligible releases at a facility if it is properly sited, designed, and permitted; achieving full public accountability of CO<sub>2</sub> geologic sequestration effectiveness; and tracking the CO<sub>2</sub> throughout the entire carbon dioxide capture and sequestration (CCS) chain for the purposes of adjusting CO<sub>2</sub> emissions reported or assigning offsets. Along those lines, some commenters urged EPA to rely on or expand the existing underground injection control (UIC) program to deal with CCS.

*Response:* EPA did not intend to characterize all CO<sub>2</sub> supplied to the economy as emissions and recognizes that there are a variety of applications for CO<sub>2</sub>, both emissive and non-emissive. CO<sub>2</sub> supplied to the economy would result in an emission if the CO<sub>2</sub> were used in an application which would ultimately result in release of the CO<sub>2</sub> to the atmosphere. EPA is also collecting information from upstream suppliers in other subparts of this rulemaking such as natural gas supply and petroleum product supply.

EPA recognizes that, in order to determine whether or not supplied CO<sub>2</sub> has been or will be released to the atmosphere (e.g., emitted), the Agency needs information on the downstream CO<sub>2</sub> end-use. In today's final rulemaking, CO<sub>2</sub> suppliers must provide information on the downstream CO<sub>2</sub> application, if known. EPA believes information on the end-use will provide some idea of the amounts of CO<sub>2</sub> which are emitted. Where that end-use is geologic sequestration (at EOR or other types of facilities), EPA will need additional information on the amount of CO<sub>2</sub> that is permanently and securely sequestered and on the monitoring and verification methodologies applied. With respect to EOR, the geology of an oil and gas reservoir can create a good barrier to trap CO<sub>2</sub> underground. Because these formations effectively stored oil or gas for hundreds of thousands to millions of years, it is believed that they can be used to store

injected CO<sub>2</sub> for long periods of time. However, EPA also recognizes that the requirements to identify a suitable GS site extend beyond geophysical trapping parameters alone and include: The evaluation and appropriate management of potential leakage pathways, appropriate rate and pressure of injection, appropriate monitoring, and other such features. While some amount of CO<sub>2</sub> injected into oil and gas reservoirs for EOR purposes will be trapped in the subsurface, these and other site-specific elements influence the amount of CO<sub>2</sub> securely sequestered and the potential for release of CO<sub>2</sub> during EOR operations.

Given the comments in support of downstream data collection, particularly with respect to EOR systems and CO<sub>2</sub> geologic sequestration (at EOR or other types of facilities), EPA plans to issue a new proposal on geologic sequestration and will consider how to address emissions and sequestration at active EOR facilities. EPA will take action on this issue in the near future with the goal that data collection for these types of facilities can begin as quickly as possible. EPA will seek comment on monitoring, reporting, and verification methodologies which can be used to determine the amount of CO<sub>2</sub> emitted and geologically sequestered at active EOR facilities and geologic sequestration sites where CO<sub>2</sub> is injected (for long-term storage) into saline aquifers, oil and gas reservoirs, or other geologic formations. Furthermore, as stated in Section III.W of this preamble, EPA plans to take additional time to consider alternatives to data collection procedures and methodologies in the proposed 40 CFR part 98, subpart W and will consider inclusion of GHG reporting from other sectors of the oil and gas industry besides those proposed for reporting in proposed 40 CFR part 98, subpart W. EOR surface facility operations may be part of those considerations. The data reported under subsequent regulatory actions and the data reported under today's rulemaking will together enable EPA to understand the amount of CO<sub>2</sub> supplied, emitted, and sequestered in the U.S., to carry out a wide variety of CAA provisions. The options that we will have considered and the resulting recommended approaches will be further fleshed out through a notice and comment process. See the next comment response for a discussion of why EPA still needs to collect CO<sub>2</sub> supplier data in today's rulemaking even though a new rulemaking on sequestration is planned.

In response to comments that EPA should rely on or expand the UIC program to address emissions of CO<sub>2</sub>,

that issue is outside the scope of this rulemaking. However, EPA agrees that the UIC program and EPA's authority under the Safe Drinking Water Act (SDWA) will provide a foundation for ensuring safe and effective containment of CO<sub>2</sub>. However, SDWA is focused on permitting sites for protection of ground and drinking water; the new proposal discussed above will be designed to address issues related to the CAA. EPA intends to harmonize CCS requirements across relevant statutory or other programs in order to minimize any redundancy and any burden on reporters. The reporting requirements in today's rulemaking for CO<sub>2</sub> suppliers and the reporting requirements in new rulemaking for CO<sub>2</sub> geologic sequestration sites will complement each other and together they can be harmonized with reporting requirements under the UIC proposed rulemaking. In a new CAA rulemaking on geologic sequestration reporting, EPA will rely on UIC permit requirements to the maximum extent possible. EPA will seek comment on these issues and will also endeavor to issue a geologic sequestration GHG reporting rule in the same time frame as it has planned for the stand-alone UIC GS rulemaking.

*Comment:* EPA received comments requesting information on how CO<sub>2</sub> supply will assist EPA in developing future climate policy. Commenters stated that they do not believe CO<sub>2</sub> supply data will provide EPA with useful information. Commenters stated that data collection from CO<sub>2</sub> suppliers does not fit within EPA's mandate from Congress to measure upstream emissions only as appropriate.

*Response:* As discussed in Sections I.C and II.Q of this preamble, EPA is collecting data from CO<sub>2</sub> suppliers in today's rule to carry out a wide variety of CAA provisions, as authorized broadly under CAA Sections 114 and 208. For example, this data will enable EPA to evaluate the appropriate action to take under section 103 regarding non-regulatory strategies for pollution prevention. It will also inform evaluation of possible CAA regulation of the supplier and/or recipient of the CO<sub>2</sub>. Data on CO<sub>2</sub> supply to the economy will allow EPA to make a well informed decision about whether and how to use the CAA to regulate facilities that capture, sequester, or otherwise receive CO<sub>2</sub> as an end-user.

Though CO<sub>2</sub> capture and geologic sequestration are occurring now on a relatively small scale, CCS is expected to play a major role in mitigating GHG emissions from a wide variety of stationary sources. According to the Inventory of U.S. Greenhouse Gas

Emissions and Sinks: 1990–2007 (EPA, April 2009), stationary sources contributed 67 percent of the total CO<sub>2</sub> emissions from fossil fuel combustion in 2007. The stationary sources represent a wide variety of sectors amenable to CO<sub>2</sub> capture; electric power plants (existing and new), natural gas processing facilities, petroleum refineries, iron & steel foundries, ethylene plants, hydrogen production facilities, ammonia refineries, ethanol production facilities, ethylene oxide plants, and cement kilns. Furthermore, 95 percent of the 500 largest stationary sources are within 50 miles of a candidate CO<sub>2</sub> reservoir.<sup>22</sup>

With this rule, EPA will begin building capacity to track the growth in CO<sub>2</sub> supply and learn about its disposition throughout the economy. EPA has concluded that we need data now from CO<sub>2</sub> suppliers—both industrial facilities and CO<sub>2</sub> production wells—in order to effectively track how the supply sources will change over time. For example, we will need to track if and by how much CO<sub>2</sub> captured from industrial facilities will offset or displace CO<sub>2</sub> produced from natural formations. Even after EPA begins collecting data on CO<sub>2</sub> geologic sequestration under the proposed new rulemaking (discussed above), EPA will continue to need data from CO<sub>2</sub> suppliers in order to track any CO<sub>2</sub> that is not sequestered.

*Comment:* EPA received some comments asking whether a specific situation results in coverage under 40 CFR part 98, subpart PP, and some comments requesting that their specific situation be exempt from coverage. For example, one commenter asked whether a facility separating CO<sub>2</sub> that is not supplied to downstream customers is a covered facility. Another asked that a pulp and paper mill that transfers a CO<sub>2</sub> stream to an adjacent facility by pipeline be exempt from 40 CFR part 98, subpart PP. Several commenters requested clarification on specific scenarios such as taking ownership of an already separated CO<sub>2</sub> stream for further processing, separating CO<sub>2</sub> for their own use, and operating versus owning the separation unit.

*Response:* EPA did not intend for 40 CFR part 98, subpart PP to cover facilities that take ownership of a CO<sub>2</sub> stream that has already been separated

and removed from a manufacturing process or that has already been extracted from CO<sub>2</sub> production wells in order to do any of the following: Store it in above ground storage of CO<sub>2</sub>; transport or distribute it via pipelines, vessels, motor carriers, or other means; purify, compress, or process it; or sell it to other commercial applications. 40 CFR part 98, subpart PP covers facilities that own or operate the equipment that physically separates and removes CO<sub>2</sub> from an industrial or manufacturing process or physically extracts CO<sub>2</sub> from production wells because we concluded that the entity with first touch of the CO<sub>2</sub> supply was the most logical point of coverage. We wanted to minimize any unnecessary duplicative reporting of the same CO<sub>2</sub> by being as specific as possible about who in the supply chain is responsible for reporting it.

We did not intend for this source category to include facilities that capture CO<sub>2</sub> for further processing or use within the fence line of the facility (e.g., for their own use). EPA proposed that 40 CFR part 98, subpart PP only cover CO<sub>2</sub> that is captured or extracted for purposes of sequestration or supply to other facilities for commercial applications because we concluded that CO<sub>2</sub> captured and used on-site is equivalent to an intermediary step in production rather than an actual supply of CO<sub>2</sub>.

*Comment:* EPA received a comment requesting that ethanol plants and other facilities capturing CO<sub>2</sub> from biomass be exempt from Subpart PP.

*Response:* A long standing inventory convention adopted by the IPCC, the UNFCCC, the US GHG Inventory, and many other reporting programs is separate treatment of emissions of CO<sub>2</sub> from the combustion of biomass and biomass-based fuels from emissions of CO<sub>2</sub> from the combustion of fossil-based products. In national inventories, emissions from the combustion of biomass-based fuels are accounted for as part of a comprehensive system-wide tracking of carbon dioxide emissions and sequestration in the land-use, land-use change and forestry sector and the agriculture sector, rather than at the point of fuel combustion. Consistent with this approach, in the proposed and final rule, downstream emitters must only consider non-biogenic emissions when conducting a threshold analysis; however, downstream emitters must report both biogenic and non-biogenic emissions once they trigger the reporting threshold because data on non-biogenic emissions is useful and informative.

For the final rule, EPA has decided not to apply the same approach to

<sup>22</sup> Dooley, JJ, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone, "Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change." Joint Global Change Research Institute, Battelle Pacific Northwest Division. May 2006. PNWD-3602. College Park, MD.

suppliers of CO<sub>2</sub>. We have concluded that data on capture of biogenic CO<sub>2</sub> would be useful and informative because biogenic CO<sub>2</sub> can potentially be stored in GS sites, or displace fossil CO<sub>2</sub> applications. We need a full picture of the CO<sub>2</sub> being supplied into the economy. Though CO<sub>2</sub> capture and sequestration is occurring now on a relatively small scale, it is expected to play a major role in mitigating GHG emissions. Therefore information on all potential sources of CO<sub>2</sub> for sequestration is necessary for a complete picture. Thus, a facility that captures CO<sub>2</sub> from biomass and otherwise meets the applicability test is covered under 40 CFR part 98, subpart PP and is required to report all CO<sub>2</sub> supplied along with the percentage of that supply that is biomass-based.

#### Monitoring and QA/QC Requirements

*Comment:* A large number of commenters requested that volumetric flow meters be allowed for purposes of calculating CO<sub>2</sub> supply in place of or in addition to mass flow meters. These comments indicated that mass flow meters are not in operation at many covered facilities, and the cost to comply with such an equipment requirement would be unnecessarily high. Some commenters suggested that reporters should be allowed to use sales contracts to determine quantity of CO<sub>2</sub> as long as the CBI is protected. Some commenters indicated that CO<sub>2</sub> liquefaction and purification facilities do not operate flow meters for the course of usual business. One of these also commented that importers and exporters of CO<sub>2</sub> do not operate flow meters for the course of usual business if they handle the product in containers and requested consideration of this incongruity.

*Response:* As a result of these comments, EPA added two equations to the methodology section of 40 CFR part 98, subpart PP in today's rule in order to ensure that all covered CO<sub>2</sub> can be reported, irrespective of technical or physical conditions. Therefore, a reporter that measures CO<sub>2</sub> in a stream using a volumetric flow meter may use this volumetric flow meter to determine quantity rather than having to purchase and install a mass flow meter. EPA has concluded that providing this additional methodology reduces the burden on reporters without compromising the quality of data received by the agency. In addition, a reporter that imports or exports CO<sub>2</sub> in containers may use weigh bills, scales, or load cells to determine quantity because applying a mass flow meter would be technically impossible. EPA has concluded that

providing this additional methodology reduces the burden on reporters without compromising the quality of data received by the agency.

The final rule does not require reporting from facilities that liquefy or purify CO<sub>2</sub> that has already been separated or removed from a manufacturing process or already extracted from production wells. Therefore we did not give consideration to the types of equipment in operation at such facilities.

Finally, the rule does not allow reporters to use sales contracts to determine quantity because EPA has concluded that reporters capturing or extracting CO<sub>2</sub> already operate mass or volumetric flow meters, or already determine quantities of CO<sub>2</sub> imported or exported in containers using weigh bills, scales, or load cells. EPA has concluded that mass and volumetric flow meters provide more accurate data than sales contracts.

#### IV. Mobile Sources

##### A. Summary of Requirements of the Final Rule

For manufacturers of engines used in mobile sources outside of the light-duty sector,<sup>23</sup> this rule includes new requirements for reporting emission rates of GHGs.<sup>24</sup> Mobile source engine manufacturers have been measuring CO<sub>2</sub> emission rates from their products for many years as a part of normal business practices and existing criteria pollutant emission certification programs, but they have not consistently reported these values to EPA. This final rule requires manufacturers to consistently measure and report CO<sub>2</sub> for all engines beginning with model year 2011 and other GHGs in subsequent model years.<sup>25</sup> Manufacturers meeting the definitions of "small business" or "small volume manufacturer" under EPA's existing mobile source emissions regulations will generally be exempt from any new GHG reporting requirements.<sup>26</sup>

<sup>23</sup> Manufacturers of light-duty vehicles, light-duty trucks, and medium-duty passenger vehicles are not covered in this final rule.

<sup>24</sup> The term "manufacturer," as well as the term "manufacturing company," as used in this preamble, means companies that are subject to EPA emission certification requirements. This primarily includes companies that manufacture engines domestically and foreign manufacturers that import engines into the U.S. market. In some cases this also includes domestic companies that are required to meet EPA certification requirements when they import foreign-manufactured engines.

<sup>25</sup> For aircraft engine manufacturers, reporting requirements will apply for the engine models in production in 2011.

<sup>26</sup> Small business manufacturers will continue to be subject to measurement and/or reporting

In addition to CO<sub>2</sub>, most manufacturers will now be required to report on two other major GHGs emitted by mobile sources, nitrous oxide (N<sub>2</sub>O) and methane (CH<sub>4</sub>). Although most current engines have relatively low emission rates of these GHGs compared to CO<sub>2</sub>, these compounds have global warming potentials significantly higher than CO<sub>2</sub>. It is important that EPA improve its understanding of these emissions from today's engines and monitor trends over time. The broad base of emission data that will begin to accrue from requirements in this rule will support emissions modeling by EPA and others, and will help guide future GHG policy.

Emissions of N<sub>2</sub>O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO<sub>x</sub> emissions. Therefore, we will require that manufacturers begin to measure and report N<sub>2</sub>O emissions, but only for engine models that incorporate NO<sub>x</sub> aftertreatment technology (as shown in Table IV-1 of this preamble). The program will not require N<sub>2</sub>O reporting before model year 2013, and the requirements will only apply to new engines equipped with NO<sub>x</sub> aftertreatment technology. (Manufacturers of some engine categories have employed aftertreatment for many years to meet NO<sub>x</sub> standards; for other engine categories, manufacturers are unlikely to introduce NO<sub>x</sub> aftertreatment technologies for some years to come.)

Emissions of CH<sub>4</sub> are a part of overall hydrocarbon emissions from mobile sources. Because CH<sub>4</sub> is not very reactive in the atmosphere, EPA has often excluded CH<sub>4</sub> from mobile source hydrocarbon regulations since it has not traditionally been a major determinant of ozone formation.<sup>27</sup> The new reporting requirements are necessary to evaluate the magnitude of mobile source CH<sub>4</sub> emissions from a GHG (rather than ozone precursor) perspective.

As described above, we are finalizing manufacturer reporting requirements for N<sub>2</sub>O and CH<sub>4</sub> emission rates in order to understand current emissions of these GHGs and to monitor potential changes as technologies and policies change in the future. However, we believe that manufacturers may be able to provide

requirements for compliance with existing regulations.

<sup>27</sup> But see *Ford Motor Co. v. EPA*, 604 F. 2d 685 (D.C. Cir. 1979) (permissible for EPA to regulate CH<sub>4</sub> under CAA section 202 (b)). In addition, although CH<sub>4</sub> is not itself regulated, manufacturers subject to "non-methane hydrocarbon" standards have needed to determine CH<sub>4</sub> emission levels, in some cases by using a default value and in many cases by way of testing.

alternative test data (and/or other information including engineering judgments based on test data) that would give EPA a reasonable basis for estimating the likely N<sub>2</sub>O and CH<sub>4</sub> emission rates for each certified engine family. Therefore, we are including a provision in this final rule that would allow a manufacturer the opportunity to provide such alternative information in lieu of N<sub>2</sub>O and/or CH<sub>4</sub> test data for each engine family.

In assessing such alternative information, EPA would consider how well the information provided by the manufacturer allows EPA to reasonably anticipate the emission performance of each of the manufacturer's engines. For example, we expect that in most cases a manufacturer wishing to omit engine testing will provide EPA with N<sub>2</sub>O test data from relevant testing programs (by such sources as industry collaboratives and/or from the suppliers of the catalytic NO<sub>x</sub> aftertreatment systems they are using on an engine. We would expect the manufacturer to also include an explanation of the manufacturer's engineering judgment as to why the data should apply to the engine family in question. For CH<sub>4</sub> emissions, our primary concern is the potential for unusually high emissions from natural gas fueled engines. Thus, we expect that in most cases a manufacturer of such an engine will provide test data on similar engines with similar catalyst systems for hydrocarbon control (with an explanation of their engineering judgment as to why the data should apply to that engine family).

The reporting requirements related to C3 marine engines and turbofan and

turbojet aircraft engines differ from other engine categories. As with other manufacturers, C3 marine engine and aircraft engine manufacturers will report CO<sub>2</sub> emission rates beginning in 2011 (for aircraft engines, they will report CO<sub>2</sub> separately for each mode of the landing and take-off (LTO) cycle used in the certification test, as well as the entire LTO cycle). For aircraft engine manufacturers, however, the reporting requirements will apply not just to engines introduced in that year, but for all engines still in production. (This should not require manufacturers to conduct any new testing, only to report existing data.) We are not requiring manufacturers of C3 marine engines and aircraft engines to measure or report N<sub>2</sub>O or CH<sub>4</sub> emission rates because of unique aspects of their industries and technologies.

C3 marine engines are very large and manufacturers generally test them as they are installed into ships rather than in a laboratory setting. For this reason, we have determined that requiring the addition of new N<sub>2</sub>O and CH<sub>4</sub> measurement equipment for C3 engines would not be practical, and, as proposed, are not requiring such reporting in this rule.

Since aircraft engine manufacturers are unlikely to employ NO<sub>x</sub> after treatment devices in the foreseeable future, we did not propose requiring N<sub>2</sub>O reporting from aircraft engines and are not finalizing any requirements in this final rule. We are not finalizing our proposed requirement that aircraft engine manufacturers measure and report CH<sub>4</sub>, as we learned that aircraft jet turbine engines have been shown to

consume CH<sub>4</sub> from the ambient air during the dominant operating modes.<sup>28</sup> However, unlike NO<sub>x</sub> emissions from most mobile sources, NO<sub>x</sub> emissions from aircraft have been shown to make a potential contribution to climate change.<sup>29</sup> For this reason, we are requiring that aircraft engine manufacturers report the NO<sub>x</sub> emission data for the LTO modes and the overall LTO cycle for all engine models currently in production, and for new engines as they are introduced. Manufacturers are already measuring NO<sub>x</sub> as part of current criteria pollutant certification requirements. NO<sub>x</sub> emissions rate data from LTO modes will support modeling of overall NO<sub>x</sub> emissions from aircraft.

For all engine categories, when a manufacturer certifies the engine in one year and then carries over the certification to subsequent years, EPA will not require re-testing of that engine model for reporting purposes.

As proposed, we are not including any requirements for mobile source fleet operators or State and local governments to report in-use travel activity or other emissions-related data in this final rule.

Table IV-1 of this preamble shows the basic reporting requirements we are finalizing in this notice for each engine category. We discuss in more detail how these reporting requirements will apply to manufacturers of each engine category in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturing."

TABLE IV-1—FIRST MODEL YEAR FOR GHG REPORTING REQUIREMENTS

Engine category	CO <sub>2</sub>	N <sub>2</sub> O <sup>a</sup>	CH <sub>4</sub>
Highway Heavy-Duty (engine and vehicle) .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Nonroad Diesel .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Marine Diesel (other than C3) .....	2011	2013 or NO <sub>x</sub> AT .....	2012
C3 Marine .....	2011	None .....	None
Locomotives .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Small Spark-Ignition .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Large Spark-Ignition .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Marine Spark-Ignition .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Snowmobiles .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Highway Motorcycles .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Off Highway Motorcycles/ATVs .....	2011	2013 or NO <sub>x</sub> AT .....	2012
Aircraft <sup>b</sup> .....	2011	None .....	None

<sup>a</sup> N<sub>2</sub>O reporting for new engines begins in 2013 or when the manufacturer introduces NO<sub>x</sub> aftertreatment technology, whichever is later.

<sup>b</sup> Applies to all turbofan and turbojet engines in production in 2011 with a rated output greater than 26.7 kilonewtons. Reporting of NO<sub>x</sub> also required.

<sup>28</sup> Aerodyne, Rich Miake-Lye, AAFEX Methane presentation at the Seventh Meeting of Primary Contributors to the Aviation Emissions Characterization Roadmap, June 9-10, 2009.

<sup>29</sup> IPCC, *Aviation and the Global Atmosphere*, 1999, at <http://www.grida.no/climate/ipcc/aviation/index.htm>, and NOAA, Written Testimony of Dr. David W. Fahey, Hearing on "Aviation and the

Environment: Emissions," Before the Committee on Transportation and Infrastructure, Subcommittee on Aviation, U.S. House of Representatives, May 6, 2008.

### B. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers."

- We are not finalizing the proposed requirements related to light-duty vehicles (including light-duty trucks and medium-duty passenger vehicles). EPA expects to propose a comprehensive light-duty GHG emission control program commencing in MY 2012 (see *Notice of Upcoming Joint Rulemaking to Establish Vehicle GHG Emissions and CAFE Standards*, 74 FR 24007 (May 22, 2009)), which is likely to contain monitoring, reporting and GHG data retention requirements that would supersede any reporting requirements established in this rule. Eliminating light-duty reporting requirements from this final rule will avoid issues of inconsistency and duplication.

- We have revised our proposal that all engine manufacturers measure and report N<sub>2</sub>O for all of their engines, and instead will require N<sub>2</sub>O reporting only for engines that use NO<sub>x</sub> exhaust aftertreatment technology.

- We have delayed the proposed MY 2011 start year for N<sub>2</sub>O reporting until MY 2013, and later for categories where the manufacturer has not applied NO<sub>x</sub> aftertreatment technology.

- We have added additional emission test methods that manufacturers can choose for measuring N<sub>2</sub>O, to assure that an appropriate method is available for any foreseeable circumstance (including the need to measure very low N<sub>2</sub>O emission rates).

- The final rule incorporates an opportunity for a manufacturer to provide EPA with appropriate alternative information in lieu of N<sub>2</sub>O and/or CH<sub>4</sub> testing, as described above.

- We have added one year of lead time to the proposed start year for reporting of CH<sub>4</sub> emissions, until 2012.

- We are not finalizing our proposal to require reporting of CH<sub>4</sub> for aircraft engines because, for the dominant operating modes, jet engines may consume CH<sub>4</sub> in the air.

- We are finalizing a requirement that we took comment on in the proposal to have aircraft engine manufacturers report NO<sub>x</sub> emissions data they already collect, since, at altitude, NO<sub>x</sub> emissions from aircraft have been shown to make a potential contribution to climate change.

- Since aircraft engines are not certified every year (there is no annual certification as is the case with other mobile sources), we have removed references to "model year" in the regulations and revised them to reflect the change to a January 1, 2011 start date for reporting CO<sub>2</sub> and NO<sub>x</sub> emissions.

### C. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. A large number of comments on mobile source were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers."

*Comment:* Light-duty vehicle manufacturers and their trade organizations raised several concerns about the timing and nature of the reporting requirements.

*Response:* We agree in part with these comments. However, more fundamentally, we have concluded that the likelihood of GHG emission regulations affecting light-duty vehicles (including light-duty trucks and medium-duty passenger vehicles) in the near future argues for consolidating any new GHG reporting requirements into that upcoming rule. Therefore, we have elected to not finalize the proposed requirements relating to these vehicles at this time, and expect to incorporate similar provisions in a proposed rule on GHG standards for light-duty vehicles in the near future.

*Comment:* Engine manufacturers and their trade organizations challenged the proposed rule in several ways. In general, they questioned the need for the data to be reported; expressed concern that the proposed timing of the requirements, especially for N<sub>2</sub>O and CH<sub>4</sub>, was too aggressive; and commented that the proposed test procedure for N<sub>2</sub>O was not adequate.

*Response:* We still conclude that there is significant value to collecting CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions rate data on the broad range of mobile sources being produced. As stated earlier, the domestic and international attention to GHGs and their effects will only grow, and the ability for EPA and the public to understand and monitor emissions from mobile sources will be increasingly important as policies relating to GHGs are considered. Collecting emissions rate data from engine manufacturers on their new engines can improve modeling of emissions for the entire mobile source sector since current

modeling relies on assumptions about N<sub>2</sub>O and CH<sub>4</sub> emissions based on a limited number of field surveys. The data from this rule will also help EPA track emissions impacts from changes in technologies and policies over time.

For N<sub>2</sub>O and CH<sub>4</sub>, we agree that revisions in the proposed provisions are warranted. We have limited the reporting requirements for N<sub>2</sub>O to engines equipped with NO<sub>x</sub> aftertreatment technology as a way to reduce the reporting burden on engine manufacturers without significantly diminishing the amount of information we receive. As discussed earlier, emissions of N<sub>2</sub>O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO<sub>x</sub> emissions, and we have concluded that collecting N<sub>2</sub>O emissions data from engines without NO<sub>x</sub> aftertreatment technology would provide marginal value to the agency. We expanded the number of approved test methods for N<sub>2</sub>O measurement since we learned from comments and our own technical research that our proposed test methods for N<sub>2</sub>O were not appropriate for every foreseeable circumstance, including measurement of very low levels of N<sub>2</sub>O. We also extended the lead time available to manufacturers before N<sub>2</sub>O and CH<sub>4</sub> reporting is required. We are providing this flexibility based on our conclusion that we can reduce the burden of purchasing and installing the required CH<sub>4</sub> and N<sub>2</sub>O emissions rate measurement equipment by extending the lead time, without significantly diminishing the amount of information we receive. Finally, as described above, the final rule includes an opportunity for a manufacturer to provide EPA with appropriate alternative information in lieu of N<sub>2</sub>O and/or CH<sub>4</sub> testing.

*Comment:* States and environmental organizations were generally supportive of the proposed reporting requirements, although some argued for earlier implementation, in 2010.

*Response:* We believe that the lead times we are finalizing for each GHG and for each engine category represent the earliest feasible timing, taking into consideration existing test capabilities and past experience, or the lack thereof.

*Comment:* Aircraft engine manufacturers commented that reporting of CO<sub>2</sub> emissions from each mode of the LTO<sup>30</sup> cycle used in the emission certification test, as proposed, is acceptable as long as existing methods for CO<sub>2</sub> are retained. In particular, commenters noted that reporting would result in minimal

<sup>30</sup> Modes of the landing and takeoff cycle are taxi/idle, takeoff, climb out, and approach.

burden as long as CO<sub>2</sub> is calculated utilizing the engine fuel mass flow rate measurements, which are currently part of the test procedure requirements for the LTO cycle. However, an industry trade association expressed concern that reporting CO<sub>2</sub> from the LTO cycle is unjustified because LTO measurements do not include CO<sub>2</sub> emissions from an entire aircraft flight, which is affected by the propulsion system, drag, etc.

*Response:* We determined that calculating aircraft engine CO<sub>2</sub> emissions from fuel mass flow rate measurements is an appropriate method for reporting CO<sub>2</sub> emissions. Therefore, for turbofan and turbojet engines of rated output greater than 26.7 kilonewtons, we are finalizing that manufacturers report CO<sub>2</sub> separately for each mode of the LTO cycle by calculation of CO<sub>2</sub> from fuel mass flow rate measurements or, alternatively, according to the measurement criteria for CO<sub>2</sub> in Appendices 3 and 5 to ICAO Annex 16, volume II. Comprehensive and consistent reporting of LTO CO<sub>2</sub> emissions, along with knowledge of aircraft aerodynamic performance, will support modeling of full-flight CO<sub>2</sub> emissions and help us to better understand overall contributions to global warming from aircraft operations.

*Comment:* Aircraft engine manufacturers raised two major issues related to our proposed CH<sub>4</sub> reporting. First, in response to EPA's request for comment on the degree to which engine manufacturers now have the needed equipment in their certification test cells to measure CH<sub>4</sub>, manufacturers replied that test stands are not currently equipped to measure CH<sub>4</sub>, and thus, they would incur additional costs to measure CH<sub>4</sub>. Second, manufacturers noted that aircraft jet turbine engines have been shown to be consumers of CH<sub>4</sub> from the ambient air during the dominant operating modes (CH<sub>4</sub> is emitted at aircraft engine idle operation, but at higher power modes aircraft engines usually consume CH<sub>4</sub>. Over the range of engine operating modes—including cruise—aircraft engines are typically net consumers of CH<sub>4</sub>).

*Response:* Given that aircraft engines are likely net consumers of CH<sub>4</sub> and that manufacturers do not currently collect CH<sub>4</sub> data as part of existing test procedures, we are not requiring CH<sub>4</sub> to be measured and reported at this time.

*Comment:* We received several responses to our request for comment on whether to require aircraft engine manufacturers to report NO<sub>x</sub> emissions in the four LTO test modes and for the overall LTO cycle. Manufacturers commented that NO<sub>x</sub> emissions do not need to be reported directly to EPA,

since this information is already voluntarily reported to the International Civil Aviation Organization (ICAO) and provided to the Federal Aviation Administration (FAA), and redundancy of reporting is unnecessary. Environmental organizations commented that EPA should require manufacturers to report NO<sub>x</sub> since they currently do not report the data to EPA. In addition, environmental organizations commented that NO<sub>x</sub> at high altitude can contribute to global warming.

*Response:* In this final rule, we are requiring that engine manufacturers of turbofan and turbojet engines of rated output greater than 26.7 kilonewtons record and report NO<sub>x</sub> emissions in the four LTO test modes and for the overall LTO cycles. As discussed in the proposal and earlier in this final rule, NO<sub>x</sub> from aircraft have been shown to make a potential contribution to climate change at high altitude. As required in 40 CFR part 87, manufacturers must already measure and record NO<sub>x</sub> emissions in each of the four LTO test modes in order to comply with the LTO NO<sub>x</sub> emission standard (for the entire LTO cycle). These data are not currently reported to EPA for public consideration as is the case with all other mobile sources. Manufacturers voluntarily report the data to ICAO, but there is no assurance that EPA will receive this information. Likewise, the information provided to FAA is not readily accessible to EPA, and it is not of the detail provided to ICAO. Comprehensive and consistent reporting of LTO NO<sub>x</sub> emissions rate data will support modeling of overall NO<sub>x</sub> emissions from aircraft and help us to better understand overall contributions to global warming from aircraft operations.

#### **V. Collection, Management, and Dissemination of GHG Emissions Data**

This section of the preamble describes the general processes by which EPA intends to collect, manage, and disseminate data under the GHG reporting rule. Section A contains a brief description of the provisions in the final rule concerning these processes, and Section B summarizes public comments and responses on data collection, management, and dissemination.

Major changes since proposal include revisions in 40 CFR 98.4 that provide flexibility for designated representatives to delegate their responsibility to agents, and to submit revisions to the certificate of representation within 90 days of a change in owners or operators (rather than 30 days). In addition, the final rule

includes a requirement that the designated representative submit the certificate of representation at least 60 days before the deadline of the facility or supplier's initial GHG report. The rationale for these and any other significant changes can be found in Section V.B of this preamble or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Designated Representative, and Data Collection, Reporting, Management, and Dissemination."

#### *A. Summary of Data Collection, Management and Dissemination for the Final Rule*

##### **1. Designated Representatives, Alternate Designated Representatives, and Agents**

Each covered facility and each supplier must identify one and only one designated representative who is responsible for certifying, signing, and submitting all submissions to EPA. A designated representative must certify and sign a submission, in accordance with the final rule, before it is considered a complete submission.

The designated representative also serves as a single point of contact for EPA to provide information about the program or a submission or to ask questions about a submission. Those facilities submitting any other emission report under 40 CFR part 75, for example, ARP facilities, must use the same designated representative for certifying, signing and submitting all submissions and reports under this rule.

Each covered facility or supplier may also identify one alternate designated representative to act in lieu of the designated representative. The alternate designated representative can perform the same duties as the designated representative, but the designated representative is responsible for ensuring the appropriate information is submitted to EPA by the timelines specified in the rule.

A designated representative or alternate designated representative may delegate the submission of information to one or more "agents." The agent can make electronic submissions to EPA, but is not allowed to certify or sign a submission. By delegating to an agent the ability to make electronic submissions to EPA, a designated representative or alternate designated representative agrees that a submission to EPA by the agent is deemed to be a submission that is certified, signed, and submitted by such designated representative or alternate designated representative.

## 2. Certificate of Representation

A designated representative must submit a certificate of representation that identifies the owners and operators of the facility or supplier, the designated representative, any alternate designated representative, and other information as specified in 40 CFR 98.4. EPA will establish an electronic data reporting system that provides for the submission of initial, as well as subsequently signed, certificates of representation.

In order to ensure sufficient processing time before a facility or supplier's initial GHG report under this part, EPA is requiring that the designated representative submit a certificate of representation at least 60 days before the deadline for the initial GHG report.

## 3. Data Collection

*Methods.* If a reporting entity already reports GHG emissions data to an existing EPA program, the Agency will make efforts to minimize any additional burden on the reporter when developing the reporting system for the final rule. Some existing programs, however, have data collection and reporting requirements that are inconsistent with the requirements for the mandatory GHG reporting rule. When it is not feasible to adapt an existing program to collect the appropriate GHG data and supplemental data, EPA will require reporters to submit the data required by the mandatory GHG reporting rule to the new data reporting system for this rule. Such reporters would also continue to submit data to the existing reporting systems for other applicable programs as required by those programs.

Reporters may fall into one or more categories:

(1) Reporters that use existing data collection and reporting methods and will not be required to report separately to the new data reporting system for the GHG reporting rule.

(2) Reporters that use existing data collection and reporting methods but will be required to report the data separately to the new data reporting system for the GHG reporting rule.

(3) Reporters that are not currently required to collect and report GHG emissions data to EPA and will be required to report using the new data reporting system for the mandatory GHG reporting rule.

For categories (2) and (3), EPA is developing a new system for reporters to submit the required data. The detailed data elements that must be reported are specified in the rule. In general, reporters using this new system must report annually to the Agency according

to the schedule specified in 40 CFR 98.3(b).

*Data Submission.* The Designated Representative (described in 40 CFR 98.4) must use an electronic signature device (for example, a personal identification number (PIN) or password) to submit a report. If the Designated Representative holds an electronic signature device that is currently used for valid electronic signatures accepted under another Agency program, we intend to design the new reporting system to also accept valid electronic signatures executed with that device where feasible. (See 40 CFR 3.10 and the definitions of "electronic signature device" and "valid electronic signature" under 40 CFR 3.3.)

*Unique Identifiers for Facilities and Units.* The Agency's reporting format for a given reporting year could make use of several ID codes—unique codes for a unit or facility. To ensure proper matching between databases, e.g., EPA-assigned facility ID codes and the Office of Regulatory Information Systems (ORIS) (DOE) ID code, and consistency from one reporting year to the next, we plan for the reporting system to provide each facility with a unique identification code to be specified by the Administrator.

*Reporting Emissions in a Single Unit of Measure.* To maintain consistency with existing State-level and Federal-level GHG programs in the U.S. and internationally, all emission measurements must be reported in the SI, also referred to as metric units. Data used in calculations and supplemental data for QA could still be submitted in English weights and measures (e.g., mmBtu/hr) but the specific units of measure must be included in the data submission. All emissions data must be submitted to the Agency in kg or metric tons per unit of time.

*Conversion of Emissions to CO<sub>2</sub>e.* Reporters must submit the quantity of each applicable GHG emitted (or other metric such as quantities supplied for industrial GHG suppliers) in two forms. The data will be in the form of quantity of the gas emitted (e.g., metric tons of N<sub>2</sub>O) per unit of time and CO<sub>2</sub>e emissions per unit of time.

*Delegation of Authority to State Agencies to Collect GHG Data.* Reporters must submit the emissions data and supplemental data directly to EPA. At this time, EPA does not intend to delegate the authority to collect data to State or local agencies.

*Submission Method.* All entities covered by this rule must report in an electronic format to be specified by the Administrator. The electronic format, which will reflect the underlying

electronic data reporting system, will be developed prior to the first reporting date. By specifying in the rule text the exact information that must be reported but not specifying the exact reporting format, EPA informs reporters about exactly what information they must report and has flexibility to modify the electronic reporting format and electronic data reporting system in a timely manner based on implementation experience and new technology. EPA has used this approach successfully in existing programs, such as the ARP and the Title VI Stratospheric Ozone Protection Program, facilitating the deployment of new reporting formats and reporting systems that take advantage of technologies such as, eXtensible Markup Language (XML), and reducing the burden on reporters and the Agency. The electronic reports submitted under this rule are subject to the provisions of 40 CFR part 3, specifying EPA systems to which electronic submissions must be made and the requirements for valid electronic signatures.

## 4. Data Management

*QA Procedures.* The new reporting system will include automated checks for data completeness, data quality, and data consistency. Such automated checks are used for many other Agency programs (e.g., ARP).

*Providing Feedback to Reporters.* EPA has established a variety of mechanisms under existing programs to provide feedback to reporters who have submitted data to the Agency. EPA will consider the approaches used by other programs (e.g., electronic confirmations, results of QA checks) and develop appropriate mechanisms to provide feedback to reporters for the GHG reporting rule when we develop the electronic data reporting system. Regardless of data collection system specifics, the goal is to ensure appropriate transparency and timeliness when providing feedback to reporters who submitted data.

## 5. Data Dissemination

*Public Access to Emissions Data.* The Agency plans to publish data submitted or collected under this rulemaking through EPA's Web site, reports, and other formats (e.g., XML), with the exception of any confidential business information (CBI) data. For further discussion of CBI, see Section II.R of this preamble.

EPA will disseminate data after the reporting deadline. The Agency recognizes the high level of public interest in this data and plans to disclose it in a timely manner, while

also assuring completeness and accuracy.

*Sharing Emission Data with Other Agencies.* There are a growing number of programs at the State, Tribe, Territory, and local level that require emission sources in their respective jurisdictions to monitor and report GHG emissions. In order to be consistent with and supportive of these programs and to reduce burden on reporters and program agencies, EPA plans to share emissions data, with the exception of any CBI data, with relevant agencies or approved entities using, where practical, common data exchange standards and infrastructure.

#### *B. Summary of Comments and Responses on Collection, Management, and Dissemination of GHG Emissions Data*

This section contains a brief summary of major comments and responses. A large number of comments on data collection, management, and dissemination were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Designated Representative and Data Collection, Reporting, Management, and Dissemination.”

#### 1. Designated Representatives, Alternative Designated Representatives, and Agents

##### *Designated Representatives*

*Comment:* Several commenters requested that EPA use the ARP definition for designated representatives to maintain consistency across the two EPA programs and provide more flexibility regarding who can be a designated representative. Other commenters requested that EPA use the responsible official definition from Title V or senior management official from TRI to maintain consistency with those programs. Other commenters raised concerns over the employment status of designated representatives.

*Comment:* A commenter noted that rule language was inconsistent in defining the relationships between designated representatives, facilities and suppliers, and owners and operators.

*Response:* EPA agrees that owners and operators should have more flexibility to identify a designated representative, including third-party representatives. EPA is striking the language requiring the designated representative to be a person responsible for the overall operation of the facility or supplier. Further, EPA is not requiring the use of

a responsible official or senior management official because either approach would be more restrictive than the designated representative definition of the final rule. EPA believes that the proposed rule was neutral with respect to the employment status of the designated representative. The final rule provides flexibility for the owners and operators to choose any individual, employee or non-employee, to represent them. EPA modified the rule to clarify that each facility and each supplier shall have one and only one designated representative and that the designated representative must be authorized by binding agreement of the owners and operators.

##### *Agents*

*Comment:* Several commenters requested that EPA allow designated representatives and alternate designated representatives the option of delegating their responsibility to prepare and submit reports to EPA to a preparer or agent. Commenters also stated that the designated representative requirement is inconsistent with Title V reporting.

*Response:* EPA agrees that it is beneficial to give the designated representatives and alternate designated representatives flexibility concerning who prepares the reports that they are responsible for submitting. The final rule does not specify who must prepare reports, but only specifies who must certify, sign, and submit them. EPA also agrees that flexibility should be provided concerning who actually submits the reports, similar to the flexibility provided in the ARP. This flexibility was implied in the provision in the proposed rule that reports be submitted “in a format specified by the Administrator,” which format has included, in other programs such as the ARP, the ability to use agents. However, EPA decided to make this flexibility explicit by including in the rule provisions allowing and setting requirements for agents selected by designated representatives or alternate designated representatives. The structure of designated representative, alternate designated representative and agent fits a wide range of circumstances from large companies to small, including those accustomed to reporting under Title V.

##### *Certification Statement*

*Comment:* Several commenters described the self-certification procedures in the proposed rule as too restrictive or suggested that the rule should be consistent with requirements of the Title V or TRI program. For example, the rule’s requirement that the

designated representative certify that they have “personally examined” the data should be replaced by the Title V requirement that a responsible official certify that they have made a “reasonable inquiry” as to the accuracy of the data.

*Response:* EPA believes that the high level of public interest in the data collected under this rule, as well as its importance to future policy, warrants establishment, by rule pursuant to CAA Sections 114, 208, and 301(a)(1), of a high standard for data quality and consistency and a high level of accountability for reported data, which will help ensure that the data quality and consistency standard is met. The certification requirements set forth in this rule are similar to the ARP (Title IV). EPA has successfully implemented this approach in the ARP and found that it provides a high degree of both data quality and consistency and accountability.

#### 2. Certificate of Representation

*Comment:* One commenter requested that EPA designate a deadline for the submission of the certificate of representation to ensure sufficient time to process the submissions.

*Response:* EPA agrees that an earlier deadline for submitting certificates of representation is advisable to provide additional lead time to process the certificates and, if necessary, verify identities and resolve issues. Because any delay in processing a certificate of representation could delay the submission of data, EPA is requiring that the designated representative submit the initial certificate of representation at least 60 days prior to the deadline for a facility or supplier’s initial GHG report.

*Comment:* Several commenters noted that a certificate of representation for each facility and supplier is burdensome either due to timing with the annual report, the need to maintain current information, or ambiguities as to whether the certificate is complete. Commenters also requested that reporters be allowed more than 30 days to submit a revised certificate of representation in the event of a change in operators or owners.

*Comment:* Several commenters requested that EPA provide an electronic system for submitting and processing certificates of representation.

*Response:* EPA does not agree that certificates of representation are unnecessary or overly burdensome or that there should be any uncertainty as to whether a certificate of representation is complete. The information required on the certificate of representation is

listed in the rule and should be well known to the owners and operators of the facility or supplier. It is the responsibility of the individual submitting the certificate to ensure its completeness. This certificate of representation has been used successfully for over a decade in the ARP.

To minimize burden, the electronic data reporting system will provide the means to electronically submit both the initial and any subsequent certificate of representation. EPA agrees that reporters should be allowed more time to update changes in owners or operators but does not agree that doing so in the annual report is sufficient. The designated representative is the primary point of contact between the owners and operators and the EPA. However, the owners and operators are ultimately responsible for compliance with the requirements of reporting rule, and it is therefore essential that the information in the certificate of representation be timely and accurate in the event EPA finds it necessary to contact the owners and operators of the facility or supplier during periods in between the submission dates of the annual reports, for example, to perform an audit. The final rule allows reporters up to 90 days to submit a revised certificate of representation when a change in owners or operators occurs. In addition, EPA modified both the owner definition and rule to clarify that the certificate of representation does not need to list persons whose legal or equitable title to or leasehold interest in a facility or supplier arises solely because they are limited partners in a partnership with legal or equitable title to, a leasehold interest in, or control of, the facility or supplier.

### 3. Data Collection Methods

*Comment:* Several commenters requested that EPA use current emission inventory reporting programs (e.g., NEI) to handle data collection or to sunset the GHG reporting rule, and instead use such programs, after five years.

*Response:* EPA is requiring electronic reports to be submitted directly to EPA using a new data reporting system for the GHG reporting rule. The rationale for the decision to report directly to EPA is contained in Sections II.N (emissions verification) and VI.B (compliance and enforcement) of this preamble. EPA recognizes the value of integrating the GHG data reported under this rule with other emission reporting programs. NEI, for example, plans to incorporate the GHG emissions data from this collection, as feasible.

*Comment:* Commenters requested that the design of the new data system be modeled on existing electronic reporting programs, incorporate measures to handle system errors, and provide opportunities for testing and user training.

*Response:* EPA agrees that a national electronic emissions database should be the basis for receiving GHG data, and that the ARP database provides a useful model for a future GHG emissions database. Data would be provided to EPA electronically to reduce the burden on the reporters and EPA, and to increase the accuracy of the reported emissions, among other reasons. The issue of transmission failures and transmission errors will be addressed in the development of the electronic reporting system. EPA agrees that it is important for data reporters to be able to confirm that their data were accepted by the system and to compare the data in the system to the data that they reported to ensure it was accurately incorporated into the database. The new data system will meet Agency requirements for security and hosting. EPA acknowledges comments supporting a "user friendly" reporting system. EPA plans to follow well known design practices within the constraints of security, accessibility and Agency design requirements.

EPA agrees with commenters on the need for testing and user training. We will continue the outreach effort undertaken during this rulemaking to encourage stakeholder participation in 'beta' testing and training opportunities.

#### *Unique Identifiers for Facilities and Units*

*Comment:* Several commenters requested that EPA assign and track corporate identifiers for reporting facilities to facilitate corporate-level analysis of emission data. Commenters also requested that EPA publish a list of identifiers for all EPA programs that a covered facility may report to.

*Response:* EPA is collecting owner and operator information through the Certificate of Representation (40 CFR 98.4). At this time, EPA is not proposing to assign unique identifiers to the owners and operators because of the complexity of ownership structures (including percentage shares of owners, subsidiaries, holding companies, and limited liability partnerships) that can be used in the multiplicity of industrial sectors required to report emission data under this rule. Although as explained earlier in the preamble, we are exploring options for adding additional data elements to the reports, such as name of parent company and NAICS code(s), to

allow easier aggregation of facility-level data to the corporate level under this program. EPA expects to subject any additional requests to notice and comment rulemaking.

EPA's Facility Registry System (FRS) links EPA program identification numbers under a unique facility record. The FRS database is publicly available to queries from the EPA.GOV Web site under the Envirofacts Data Warehouse home page: [http://www.epa.gov/enviro/html/fii/fii\\_query\\_java.html](http://www.epa.gov/enviro/html/fii/fii_query_java.html). Descriptive information about FRS can be found at: <http://www.epa.gov/enviro/html/fii/index.html>. FRS may be searched by program identification, facility name or geographic location. The Agency will continue to make FRS and all program identification numbers readily available and will include the facilities reporting under this rule in the FRS collection of program ID's once public release of the data is authorized.

#### *Submission Method*

*Comment:* Several commenters requested that EPA specify the format of the data collection methods and subject it to public comment before finalizing the rule. These commenters indicated that without the details of the data collection methods it was not possible to evaluate the GHG reporting rule, including implementation costs and reporting burden.

*Response:* The final rule requires reports to be submitted "in a format specified by the Administrator." EPA is thereby retaining the flexibility to specify the electronic format, and the underlying electronic reporting system reflected in the format, after promulgation of this rule but well before the first reporting deadline and, if necessary, to change the electronic format and electronic reporting system based on implementation experience and new technology. Several other reporting programs (e.g., ARP) use a similar approach where the specific electronic reporting system is not included within the rule or subjected to formal notice and comment. The relevant subparts of the proposed GHG reporting rule specified the data elements that each entity must report, and therefore parties could evaluate the reporting burden and costs under the proposed rule and had an opportunity to comment on that aspect of the proposed rule. In addition, before specifying the electronic format and underlying electronic reporting system, EPA will conduct outreach and provide opportunities for stakeholder feedback on the specific reporting format and reporting system.

*Comment:* Several commenters requested that EPA provide alternative methods to report emission data, including paper submissions, scanned documents, and direct data upload.

*Response:* EPA is requiring electronic reporting of the GHG and supplemental data to increase the accuracy and timeliness of the reported emission data and is not providing options for paper or scanned GHG reports. Requiring electronic submission of data allows EPA to conduct electronic QA testing of all such data when it is received and to provide electronic feedback to the reporters almost instantaneously. This gives reporters the opportunity to correct any errors, or to provide explanations of potentially problematic data, within a short time frame, thereby increasing the accuracy and timeliness of the data. Moreover, electronically submitted data can be readily sorted and analyzed by EPA and members of the public. In contrast, submission of hardcopy data (whether in paper or scanned documents) would make audit and correction, as well as sorting and analysis, of the data much more cumbersome, inefficient, and time consuming. Indeed, particularly in light of the large number of facilities and suppliers that will be reporting and the large amounts of reported data that will be received as a result, the ability to audit and analyze the data received in hardcopy format would likely be significantly limited. This would adversely affect the usefulness, as well as the accuracy and timeliness of the data.

In requiring electronic data submission, EPA will provide a Web-based reporting system to guide reporters through the data entry, emission calculation, and submission process. This reporting system will conform to EPA information technology standards and 40 CFR part 3. In addition, EPA will provide a mechanism for reporters to submit data files directly to EPA using a standard format (e.g., XML) to be prescribed by the Administrator before the first reporting date. To reduce the burden on reporters and reduce errors, EPA will conduct outreach and training for reporters on the reporting format and underlying reporting systems. EPA will also provide a hotline to answer questions about the program and reporting format and reporting systems. EPA expects that most reporters affected by this rule are already familiar with Web-based or electronic reporting systems through other EPA programs.

#### *Delegation of Authority to State Agencies To Collect GHG Data*

*Comment:* Several commenters requested that EPA delegate rule implementation, including data collection, to State and local agencies. These commenters indicated that several States already have GHG reporting requirements and have systems in place to collect and verify this data, and suggested that delegation of the rule could help reduce inconsistency or duplication of effort between State programs and this Federal mandatory GHG reporting rule. Other commenters supported requiring facilities to submit data directly to EPA, without delegation of data collection to State and local agencies, in order to provide national consistency.

*Response:* EPA is requiring electronic reports to be submitted directly to EPA, and is not delegating data collection to State and local agencies. The rationale for this decision is provided in Section VI.B of this preamble.

#### 5. Data Dissemination

##### *Public Access to Emissions Data*

*Comment:* Several commenters supported EPA's proposal to make the data submitted under the reporting rule available to the public. Some requested that data be published in real time, while others requested the data be released in a timely manner.

*Response:* With the exception of CBI, EPA intends to make data submitted under this program available to the public in a timely manner after the reports have been submitted and EPA has completed QA/QC of the data. To that end, EPA intends to establish a new reporting system that will accept electronic submissions of GHG emissions and supporting data and facilitate EPA's verification of the submissions. EPA plans to provide public access to the data by posting electronic data on a Web site in a timely manner after the reporting deadline. This level of transparency is important to public participation in future policy development and for building public confidence in the quality of the data collected.

##### *Sharing Emissions Data With Other Agencies*

*Comment:* Some commenters stressed that electronic data reporting systems need to be consistent and inter-operable and allow data exchange between TCR, State rules, NEI, ARP, other stakeholders and EPA.

*Response:* EPA will continue to coordinate with other Federal, State, and regional programs and will make

efforts to facilitate data exchange when designing the data reporting system that will be used for the GHG reporting rule. EPA intends to employ inter-operable data exchange standards. EPA intends to design and manage the GHG data collection to take advantage of existing efforts on data exchange standards and to work with stakeholder groups to promote the easy exchange and sharing of the data collected under this rule. For example, EPA is extending the Consolidated Emissions Reporting Schema (CERS), currently in use by the EPA's NEI program, to support data reporting and publication under this rule. EPA also intends to use existing tools, such as FRS and SRS, to ensure data consistency.

To the extent possible, EPA will consider existing reporting systems and work with those programs and systems to develop a reporting scheme that facilitates data exchange. EPA anticipates that this coordination will reduce the burden of reporting for both reporters and government agencies. However, as explained in Section II.O of this preamble, the various reporting programs do not have identical data needs and requirements. Therefore, at this time, it is not possible for companies reporting under State and Federal rules and voluntary programs to file a single report that will satisfy all reporting requirements.

*Comment:* Commenters requested that the data system utilize common standards, such as XML and geographic identifiers, and provide descriptive text wherever codes or abbreviations are used.

*Response:* EPA agrees that publishing the results of this data collection using common, standards-based schemas and formats will promote the exchange of data between EPA, States and other entities. The published results will include the latitude and longitude of facilities as well as help text with definitions of codes and abbreviations.

#### **VI. Compliance and Enforcement**

This section of the preamble generally describes the compliance assistance and enforcement activities EPA intends to implement for the GHG reporting rule and summarizes public comments and responses on compliance assistance, role of the States, and enforcement.

##### *A. Compliance and Enforcement Summary*

###### 1. Compliance Assistance

EPA plans to conduct an active outreach and technical assistance program following publication of the final rule. The primary audience is

potentially affected industries. We intend to develop implementation and outreach materials and training to help potential reporters understand whether the rule applies to them and explain the reporting requirements and timetables. The program particularly will target industrial, commercial, and institutional sectors that do not routinely deal with air pollution regulations.

Compliance materials will be tailored to the needs of various sectors. These materials might include, for example, fact sheets, information sheets, plain English guides, frequently asked question and answer documents, applicability tools, monitoring and recordkeeping checklists, and training on rule requirements and the electronic reporting system. We also expect to implement a compliance assistance e-mail and telephone hotline for answering questions and providing technical assistance. Note that while EPA plans to issue compliance assistance materials, reporters should always consult the final rule to resolve any ambiguities or questions.

## 2. Role of the States

While EPA does not intend to formally delegate data collection and enforcement of the GHG reporting rule to State agencies, EPA will likely enlist State assistance, when it is available, for outreach and compliance assistance with the final rule. (However, State and local agencies will not be required to provide EPA any assistance with these activities, given State and local agency resource constraints and priorities.). State and local air pollution control agencies routinely interact with many of the sources that would report under this rule. Further, several States have experience implementing State mandatory GHG reporting and reduction programs. Therefore, we plan to work with those State and local agencies that are able to assist EPA to define their role in communicating the requirements of the rule and providing compliance assistance. In concert with their routine inspection and other compliance and enforcement activities for other CAA programs, State and local agencies may also be able to assist with educating facilities and assuring compliance at facilities subject to this rule.

## 3. Enforcement

Facilities or suppliers that fail to monitor or report GHG emissions, quantities supplied, or other data elements according to the requirements of the applicable rule subparts could potentially be subject to enforcement action by EPA under CAA sections 113 and 203–205. The CAA provides for

several levels of enforcement that include administrative, civil, and criminal penalties. The CAA allows for injunctive relief to compel compliance and civil and administrative penalties of up to \$37,500 per day per violation.<sup>31</sup>

Actions (or inactions) that could ultimately be considered violations include but are not limited to the following:

- Failure to report GHG emissions (for suppliers, the emissions that would result from combustion or use of the products they supply).
- Failure to collect data needed to calculate GHG emissions.
- Failure to continuously monitor and test as required. Note that merely filling in missing data as specified does not excuse a failure to perform the monitoring or testing.
- Failure to calculate GHG emissions according to the methodology(s) specified in the rule.
- Failure to keep required records needed to verify reported GHG emissions.
- Falsification of reports.

### *B. Summary of Public Comments and Responses on Compliance and Enforcement*

This section contains a brief summary of major comments and responses. A large number of comments on compliance and enforcement were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Compliance and Enforcement.”

#### 1. Role of States in Compliance and Enforcement

*Comment:* Several commenters requested that EPA delegate rule implementation, including data collection, emissions verification, and enforcement of the rule to State and local agencies. These commenters indicated that several States already have GHG reporting requirements and have systems in place to collect and verify these data, and they suggested that delegation of the rule could help reduce inconsistency or duplication of effort between State programs and this

Federal mandatory GHG reporting rule. However the majority of commenters, including industry, environmental organizations, and many public citizens supported requiring facilities to submit data directly to EPA, without delegation of data collection or emissions verification to State and local agencies, in order to provide national consistency.

*Response:* Section 114(b) of the CAA allows EPA to delegate to States the authority to implement and enforce Federal rules. At this time, however, EPA does not propose to formally delegate implementation of the rule (such as data collection and enforcement activities) to State and local agencies, as discussed in Section II.O of this preamble. The goal of data collection under this rule is to establish a consistent, verified, national data set that is available to EPA, States, other agencies, policy makers, and the public for use in developing and implementing future GHG policies and reduction programs. To meet these data consistency and timeliness constraints, and to serve policy objectives, it is most efficient to have the data submitted directly into one central EPA system and have centralized emissions data verification. Direct reporting to EPA will also help us better understand and address common compliance problems that may arise from the GHG reporting rule.

EPA recognizes that several States already have mandatory GHG reporting programs that are broader in scope, in a more advanced state of development, and have different policy objectives than this rulemaking. These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also have catalyzed important GHG reductions.

As discussed in Section II.O of this preamble, we are committed to working with States and other groups (e.g. TCR, Environmental Council of the States (ECOS)) to develop electronic reporting tools that can both collect and share data in an efficient and timely manner. At this time, EPA is in the process of developing the reporting format and tools and therefore has not specified the exact reporting format, other than it will be electronic, in order to maintain flexibility to modify the reporting format and tools in a timely manner. To the extent possible, EPA will work with existing reporting programs and systems to develop a reporting scheme that minimizes the burden on sources.

While EPA is not delegating authority to the States, we will work with States as we develop rule implementation plans to determine appropriate

<sup>31</sup> The Federal Civil Penalties Inflation Adjustment Act of 1990, Public Law 101–410, 104 Stat. 890, 28 U.S.C. 2461, note, as amended by Section 31001(s)(1) of the Debt Collection Improvement Act of 1996, Public Law 104–134, 110 Stat. 1321–373, April 26, 1996, requires EPA and other agencies to adjust the ordinary maximum penalty that it will apply when assessing a civil penalty for a violation. Accordingly, EPA has adjusted the CAA’s provision in Section 113(b) and (d) specifying \$25,000 per day of violation for civil violations to \$37,500 per day of violation.

implementation roles, such as assisting with outreach efforts and site visits to audit facility reports. For related comments and responses, please see the following sections of this preamble: II.N (verification approach), II.O (role of States) and II.R (CBI).

## 2. Enforcement

*Comment:* Some commenters suggested that States should be allowed to participate in the enforcement of the GHG reporting rule, perhaps through delegated enforcement authority.

*Response:* EPA welcomes States' interest in helping EPA enforce this or any other Federal rule and we will work with States to determine appropriate roles as described above. We do not plan to delegate the enforcement of this rule in the same sense that we do under other CAA programs such as the NESHAP program in which, for example, notices may be sent only to the delegated States. If a State would like the authority to enforce this rule, then the State may adopt the provisions of this GHG reporting rule into State laws or regulations by reference. This would make the provisions enforceable as a matter of State law which can be enforced in a State court.

*Comment:* Some commenters stated that they should be able to petition EPA to enforce against violators where they have evidence of or suspect violations.

*Response:* EPA welcomes any tips from citizens about suspected violations of this or any rule through our tips Web site, <http://www.epa.gov/tips>. However, we are not including a formal petition process in the rule because such a process was not proposed. We do not favor a formal petition process because a formal petition is not necessary for us to investigate concerns raised by citizens and such a process might take extra time or divert resources from other priorities.

*Comment:* Some commenters stated that a flexible enforcement policy is needed. They noted that the proposed rule cited the CAA for the authority for the GHG reporting rule and stated that a violation of the reporting rule is a violation of the CAA and subject to maximum daily penalties allowed under the CAA. However, the commenters were concerned that the maximum penalty should not be applied in most cases and argued that there are many instances when a less severe action is appropriate.

*Response:* EPA agrees with the commenters that flexibility is needed in enforcing the rule. The penalty cited in the proposal preamble and rule is a statutory maximum, and would not be applied in every case. EPA's objective

with the reporting rule is to collect accurate GHG data in a timely manner. In order to achieve that objective, EPA will generally work with sources that must submit GHG reports in order to facilitate compliance and provide the needed data to EPA. The CAA allows EPA discretion to pursue a variety of informal and formal actions in order to achieve compliance. While EPA is committed to working with reporters to ensure accuracy, this does not relieve reporters from their obligation to report data that are complete, accurate, and in accordance with the requirements of this rule.

In many instances, based on past enforcement experience, less punitive enforcement actions are exhausted before more punitive fines and penalties are imposed on a non-complying source. These less punitive actions may include a warning to the source that it is in non-compliance along with advice on what needs to be done to comply and a request for response from the facility. Initial actions may also include a formal legal notification from EPA that defines the violation, provides evidence, and requires (orders) corrective actions by specific dates. The EPA enforcement office always uses discretion and takes case-specific circumstances into account when determining the appropriate actions to address violations of CAA rules. We will continue to do so in enforcing the reporting rule, and we are not laying out a specific enforcement policy or hierarchy in order to maintain the necessary flexibility.

## VII. Economic Impacts on the Rule

This section of the preamble examines the costs and economic impacts of the GHG reporting rule, including the estimated costs and benefits of the rule, and the estimated economic impacts of the rule on affected entities, including estimated impacts on small entities. Complete detail of the economic impacts of the final rule can be found in the text of the Regulatory Impact Analysis (RIA) for the final rule (EPA-HQ-OAR-2008-0508).

This section also contains a brief summary of major comments and responses. A large number of comments on economic impacts of the rule were received covering numerous topics. Responses to significant comments received can be found in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Cost and Economic Impacts of the Rule."

*A. How were compliance costs estimated?*

### 1. Summary of Method Used To Estimate Compliance Costs

EPA estimated costs of complying with the rule for reporting process emissions of GHGs in each affected industrial facility, as well as emissions from stationary combustion sources at industrial facilities and other facilities, GHG and supply data from fuel suppliers and industrial gas suppliers, and GHG data for mobile sources. 2006 is the representative year of the analysis in that the annual costs were estimated using the 2006 population of emitting sources. EPA used available industry and EPA data to characterize conditions at affected sources. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility and the associated costs were estimated.

The costs of complying with the rule will vary from one facility to another, depending on the types of emissions, the number of affected sources at the facility, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for performing the monitoring, recordkeeping, and reporting activities necessary to comply with the rule. For some facilities, costs include costs to monitor, record, and report emissions of GHGs from production processes and from stationary combustion units. For other facilities, the only emissions of GHGs are from stationary combustion. EPA's estimated costs of compliance are discussed in greater detail below:

*Labor Costs.* The costs of complying with and administering this rule include time of managers, technical, and administrative staff in both the private sector and the public sector. Staff hours are estimated for activities, including:

- *Monitoring (private):* Staff hours to operate and maintain emissions monitoring systems.

- *Reporting (private):* Staff hours to gather and process available data and reporting it to EPA through electronic systems.

- *Assuring and releasing data (public):* Staff hours to quality assure, analyze, and release reports.

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

*Equipment Costs.* Equipment costs include both the initial purchase price of monitoring equipment and any

facility/process modification that may be required. For example, the cost estimation method for mobile sources involves upstream measurement by the vehicle manufacturers. This may require an upgrade to their test equipment and facility. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with appropriate lifetime and interest rate assumptions. Cost recovery periods and interest rates vary by industry, but typically, one-time capital costs are amortized over a 10-year cost recovery period at a rate of seven percent.

## 2. Summary of Comments and Responses

*Comment:* A majority of the comments received on the compliance costs of the reporting rule focused on facility level costs for monitoring and reporting. Commenters noted that costs estimated for a representative facility may differ from actual facility level costs. Some commenters specifically referred to the costs associated with installing and maintaining capital equipment. Other commenters noted that some source categories had higher estimated compliance costs than others. Several commenters expressed confusion over how combustion related monitoring costs are added to process related monitoring costs.

*Response:* EPA recognizes that the costs presented for facilities represent costs that would be incurred by a representative facility, and may not reflect the costs that would be incurred by each individual facility in each industry because facilities affected by each subpart vary.

Nevertheless, after reviewing the comments received, EPA has determined that its analysis provides a reasonable characterization of costs for facilities affected by each subpart and that its documentation provides adequate documentation of how the costs were estimated. As described in the next section, EPA collected and evaluated cost data from multiple sources, and weighed the analysis prepared at proposal against the input received through public comments. In any analysis of this type, there will be variations in costs among facilities, and after thoroughly reviewing the available information, we have concluded that the costs developed for this rule appropriately reflect a "representative facility" in the sector.

The costs facing facilities in some sectors include not only process costs but additional costs associated with other subparts of the rule. While these costs are presented individually in Section 4 of the RIA for the final rule,

where these conditions apply the costs are summed across applicable subparts and compared to revenues in the economic and small entity impact analyses.

## B. What are the costs of the rule?

### 1. Summary of Costs

For the cost analysis, EPA gathered existing data from EPA, industry trade associations, States, and publicly available data sources (e.g., labor rates from the BLS) to characterize the processes, sources, sectors, facilities, and companies/entities affected. EPA also considered cost data submitted in public comments on the proposed rule, as further discussed in Section VII.B.2 of this preamble. Costs were estimated on a per entity basis and then weighted by the number of entities affected at the 25,000 metric tons CO<sub>2</sub>e threshold.

To develop the costs for the rule, EPA estimated the number of affected facilities in each source category, the number and types of combustion units at each facility, the number and types of production processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and the measurements that are already being made for reasons not associated with the rule (to allow only the incremental costs to be estimated). Many of the affected source categories, especially those that are the largest emitters of GHGs (e.g., electric utilities, industrial boilers, petroleum refineries, cement plants, iron and steel production, pulp and paper) are subject to national emission standards and we use data generated in the development of these standards to estimate the number of sources affected by the reporting rule.

Other components of the cost analysis included estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored; and engineering judgment by industry and EPA industry experts and engineers. Labor costs were taken from the BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring.

A detailed engineering analysis was conducted for each subpart of the rule to develop unique unit costs. This analysis is documented in the RIA for the final rule. The TSDs for each source category provide a discussion of the applicable measurement technologies and any existing programs and practices. The appropriate volume of "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments" for each source category provide responses to any public comments on these source category engineering and cost analyses. Section 4 of the RIA for the final rule contains a description of the engineering cost analysis.

Table VII-1 of this preamble presents by subpart: The number of entities, the downstream emissions covered, the first year capital costs and the first year annualized costs of the rule. EPA estimates that the total national annualized cost for the first year is \$132 million, and the total national annualized cost for subsequent years is \$89 million (2006\$). Of these costs, roughly 13 percent fall upon the public sector for program administration in the first year, while 87 percent fall upon the private sector. General stationary combustion sources, which are widely distributed throughout the economy, are estimated to incur approximately 26 percent of costs in the first year; other sectors incurring relatively large shares of costs are pulp and paper manufacturing (9 percent) and vehicle and engine manufacturers (9 percent).

The threshold, in large part, determines the number of entities required to report GHG emissions and hence the costs of the rule. The number of entities excluded increases with higher thresholds. Table VII-2 of this preamble provides the cost-effectiveness analysis for various thresholds examined. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per metric ton of emissions reported (\$/metric ton CO<sub>2</sub>e). The second metric for evaluating the threshold option is the incremental cost of reporting emissions. The incremental cost is calculated as the additional (incremental) cost per metric ton starting with the least stringent option and moving successively from one threshold option to the next. For more information about the first year capital costs (unamortized), project lifetime and the amortized (annualized) costs for each subpart, please refer to section 4 of the RIA for the final rule and the RIA cost appendix. Not all subparts require capital expenditures but those that do

are clearly documented in the RIA for the final rule.

TABLE VII-1—ESTIMATED COVERED ENTITIES, EMISSIONS AND COSTS BY SUBPART (2006\$)

Subpart	Number covered of entities	Downstream emissions		First year capital costs		First year total annualized costs <sup>2</sup>	
		(Million of MtCO <sub>2</sub> e)	Share (percent)	(Million)	Share (percent)	(Million)	Share (percent)
Subpart A—General Provisions .....	0	0.0	0	\$0.0	0	\$0.0	0
Subpart B—Reserved .....	0	0.0	0	0.0	0	0.0	0
Subpart C—General Stationary Fuel Combustion Sources .....	3,000	220.0	6	10.5	27	25.8	20
Subpart D—Electricity Generation .....	1,108	2262.0	59	0.0	0	3.3	2
Subpart E—Adipic Acid Production .....	4	9.3	0	0.0	0	0.1	0
Subpart F—Aluminum Production .....	14	6.4	0	0.0	0	0.2	0
Subpart G—Ammonia Manufacturing .....	23	12.9	0	0.0	0	0.4	0
Subpart H—Cement Production .....	107	86.8	2	5.4	14	6.8	5
Subpart K—Ferroalloy Production .....	9	2.3	0	0.0	0	0.1	0
Subpart N—Glass Production .....	55	2.2	0	0.0	0	0.5	0
Subpart O—HCFC-22 Production .....	3	13.8	0	0.0	0	0.0	0
Subpart P—Hydrogen Production .....	41	15.0	0	0.0	0	0.4	0
Subpart Q—Iron and Steel Production .....	121	85.0	2	0.0	0	3.7	3
Subpart R—Lead Production .....	13	0.8	0	0.0	0	0.1	0
Subpart S—Lime Manufacturing .....	89	25.4	1	4.9	12	5.3	4
Subpart U—Miscellaneous Uses of Carbonates ..	0	0.0	0	0.0	0	0.0	0
Subpart V—Nitric Acid Production .....	45	17.7	0	0.2	1	0.9	1
Subpart X—Petrochemical Production .....	80	54.4	1	0.0	0	2.2	2
Subpart Y—Petroleum Refineries .....	150	204.7	5	1.6	4	6.1	5
Subpart Z—Phosphoric Acid Production .....	14	3.8	0	0.8	2	0.8	1
Subpart AA—Pulp and Paper Manufacturing .....	425	57.7	2	14.8	37	8.6	7
Subpart BB—Silicon Carbide Production .....	1	0.1	0	0.0	0	0.0	0
Subpart CC—Soda Ash Manufacturing .....	5	3.1	0	0.0	0	0.1	0
Subpart EE—Titanium Dioxide Production .....	8	3.7	0	0.0	0	0.1	0
Subpart GG—Zinc Production .....	5	0.8	0	0.0	0	0.1	0
Subpart HH—Landfills .....	2,551	91.1	2	1.3	3	12.4	9
Subpart JJ—Manure Management .....	107	4.5	0	0.0	0	0.3	0
Subpart LL—Suppliers of Coal & Subpart MM—Suppliers of Petroleum Products .....	315	0.0	0	0.0	0	3.7	3
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids .....	1,502	0.0	0	0.0	0	6.8	5
Subpart OO—Suppliers of Industrial Greenhouse Gases .....	167	643.4	17	0.0	0	0.5	0
Subpart PP—Suppliers of Carbon Dioxide (CO <sub>2</sub> ) .....	13	0.0	0	0.0	0	0.0	0
Subpart QQ—Motor Vehicle and Engine Manufacturers .....	317	NA	NA	0.0	0	8.6	7
Coverage Determination Costs for Non-Reporters .....	NA	NA	NA	NA	NA	17.2	13
Private Sector, Total .....	10,152	3,827	100	39.6	100	115.0	87
Public Sector, Total .....	NA	NA	NA	NA	NA	17.0	13
<b>Total .....</b>	<b>10,152</b>	<b>3,827</b>	<b>100</b>	<b>39.6</b>	<b>100</b>	<b>132.0</b>	<b>100</b>

<sup>1</sup> Emissions from upstream facilities are excluded from these estimates to avoid double counting.

<sup>2</sup> Total costs include labor and capital costs incurred in the first year. Capital Costs are annualized using appropriate equipment lifetime and interest rate (see additional details in section 4 of the RIA for the final rule).

TABLE VII-2—THRESHOLD COST-EFFECTIVENESS ANALYSIS (2006\$)

Threshold (tons CO <sub>2</sub> e)	Facilities required to report	Total costs (million \$2006)	Downstream emissions reported (MtCO <sub>2</sub> e/year)	Percentage of total downstream emissions reported (percent)	Average reporting cost (\$2006/ton)	Incremental cost (\$/metric ton)
100,000 .....	6,269	\$89	3,738	53	\$0.02	
25,000 .....	10,152	132	3,827	54	0.03	0.49
10,000 .....	16,718	160	3,861	55	0.04	0.83
1,000 .....	54,229	398	3,926	56	0.10	3.67

\* Cost per metric ton relative to the selected option.

**Note:** Does not include emissions for Motor Vehicle and Engine Manufacturers (Subpart QQ).

Table VII-3 of this preamble presents costs broken out by upstream and downstream sources. Upstream sources include the fuel suppliers and industrial GHG suppliers. Downstream suppliers include combustion sources, industrial processes, and biological processes.

Most upstream facilities (e.g., refineries) are also direct emitters of GHGs and are included in the downstream side of the table. As shown in Table VII-3 of this preamble, over 99 percent of industrial processes emissions are covered at the 25,000 metric tons CO<sub>2</sub>e threshold for a

cost of approximately \$36 million. However, it should be noted that due to data limitations the coverage estimates for upstream and downstream source categories are approximations.

TABLE VII-3—UPSTREAM VERSUS DOWNSTREAM COSTS

Upstream <sup>1</sup>				Downstream <sup>2,3,4</sup>			
Source category	No. of reporters	Emissions coverage (%) <sup>10</sup>	First year cost (millions)	Source category	No. of reporters <sup>2</sup>	Emissions coverage <sup>3,7,10</sup> (%)	First year cost <sup>3</sup> (millions)
Coal Supply .....	0	0	\$0.00	Coal <sup>5,6</sup> Combustion .....	N/A	99.0	N/A
Petroleum Supply .....	315	100	3.66	Petroleum <sup>5</sup> Combustion <sup>9</sup> .....	N/A	20.0	N/A
Natural Gas Supply .....	1,502	68	6.76	Natural Gas <sup>5</sup> Combustion .....	N/A	23.0	N/A
				Sub Total Combustion .....	4,108	N/A	\$29.04
Industrial Gas Supply .....	167	100	0.52	Industrial Gas Consumption .....	17	14	0.24
				Industrial Processes .....	1,068	99.6	36.2
				Fugitive Emissions (coal, oil and gas) .....	0	0	0.00
				Biological Processes .....	2,658	58	12.77
				Vehicle <sup>8</sup> and Engine Manufacturers .....	317	80	8.61

**Notes**

- <sup>1</sup> Most upstream facilities (e.g., refineries) are also direct emitters of greenhouse gases, and are included in the downstream side of the table.
- <sup>2</sup> Estimating the total number of downstream reporters by summing the rows will result in double-counting because some facilities are included in more than one row due to multiple types of emissions (e.g., facilities that burn fossil fuel and have process/fugitive/biological emissions will be included in each downstream category).
- <sup>3</sup> The coverage and costs for downstream reporters apply to the specific source category, i.e., the fixed costs are not “double-counted” in both stationary combustion and industrial processes for the same facility.
- <sup>4</sup> The thresholds used to determine covered facilities are additive, i.e., all of the source categories located at a facility (e.g., stationary combustion and process emissions) are added together to determine whether a facility meets the threshold (e.g., 25,000 metric tons of CO<sub>2</sub>e/yr).
- <sup>5</sup> Estimates for the number of reporters and total cost for downstream stationary combustion do not distinguish between fuels. National level data on the number of reporters could be estimated. However, estimating the number of reporters by fuel was not possible because a single facility can combust multiple fuels. For these reasons there is not a reliable estimate of the total of the emissions coverage from the downstream stationary combustion.
- <sup>6</sup> Approximately 90 percent of downstream coal combustion emissions are already reported to EPA through requirements for electricity generating units under the ARP.
- <sup>7</sup> Due to data limitations, the coverage for downstream sources for fuel and industrial gas consumption in this table does not take into account thresholds. Assuming full emissions coverage for each source slightly over-states the actual coverage that will result from this rule. To estimate total emissions coverage downstream, by fuel, we added total emissions resulting from the respective fuel combusted in the industrial and electricity generation sectors and divided that by total national GHG emissions from the combustion of that fuel.
- <sup>8</sup> The percent of coverage here is percentage of total heavy-duty highway vehicles and engines, motorcycles, and nonroad engine sales covered by manufacturer reporting in this proposal rather than emissions coverage. The “threshold” for mobile sources is based on manufacturer size rather than total emissions. In this rule, all heavy-duty highway and nonroad vehicle and engine manufacturers, except those that meet EPA’s definition of “small business” or “small volume manufacturers”, would report emissions rates of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O from the products they supply. This source category is neither upstream nor downstream, but is included in the downstream column for illustrative purposes.
- <sup>9</sup> The emissions coverage for petroleum combustion includes combustion of fuel by transportation sources as well as other uses of petroleum (e.g., home heating oil). It cannot be broken out by transportation versus other uses as there are difficulties associated with tracking which products from petroleum refiners are used for transportation fuel and which were not. We know that although refiners make these designations for the products leaving their gate, the actual end use can and does change in the market. For example, designated transportation fuel can always be used as home heating oil.
- <sup>10</sup> Emissions coverage from the combustion of fossil fuels upstream represents CO<sub>2</sub> emissions only. It is not possible to estimate nitrous oxide and methane emissions without knowing where and how the fuel is combusted. In the case of downstream emissions from stationary combustion of fossil fuels, nitrous oxide and methane emissions are included in the emissions coverage estimate. They represent approximately one percent of the total emissions.

2. Summary of Comments and Responses

*Comment:* EPA received comments on source specific cost data reflected in the engineering cost analysis presented in section 4 of the RIA for the proposed rule (EPA-HQ-OAR-2008-0318-002). Some commenters asked EPA to not overly burden entities that may be required to report and to balance reporting costs with the need for accurate reporting of GHG emissions.

Additional comments received questioned EPA’s estimate of the costs associated with third party verification, as well as the estimated burden to the Federal government for self certification with EPA verification.

*Response:* EPA considered all relevant comments regarding source specific cost data developed in the engineering cost analysis and used in the RIA for the proposed rule. In some cases, we revised our cost estimates, and in some cases we revised monitoring and reporting requirements in ways which

reduced burden. Please see source specific comments and responses in Section III of this preamble and the relevant volume of “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments”.

EPA believes the selected option for the mandatory GHG reporting rule strikes a balance between impacts on small entities, consistency with other programs, costs incurred by the reporting entities, and emissions coverage. Section 5 of the RIA for the

final rule provides cost comparisons for each alternative evaluated.

In evaluating the costs of self certification with EPA verification and third party verification, EPA conducted a thorough review of relevant cost information available. EPA also considered cost data submitted in public comments on the proposed rule. EPA's review of verification costs included examining estimated Agency costs for other EPA based reporting programs, as well as a study conducted by the California Air Resources Board (CARB). The results of EPA's review of verification costs can be found in the Memo on Verification Costs in the docket. The final rule retains self-certification with EPA verification. EPA's estimated cost for verification activities is \$7 million per year. Additional comments and responses on third party verification can be found in Section II.N of this preamble. Section 5.1.6 of the RIA for the final rule

contains the full economic analysis of verification costs and options.

*C. What are the economic impacts of the rule?*

1. Summary of Economic Impacts

EPA prepared an economic impact analysis to evaluate the impacts of the rule on affected industries and economic sectors. In evaluating the various reporting options considered, EPA conducted a cost-effectiveness analysis, comparing the cost per metric ton of GHG emissions across reporting options. EPA used this information to identify the preferred options described in today's rule.

To estimate the economic impacts of the rule, EPA first conducted a screening assessment, comparing the estimated total annualized compliance costs by industry, where industry is defined in terms of North American Industry Classification System (NAICS) code, with industry average revenues.

Overall national costs of the rule are significant because there is a large number of affected entities, but per-entity costs are low. Average cost-to-sales ratios for establishments in affected NAICS codes are uniformly less than 0.8 percent.

These low average cost-to-sales ratios indicate that the rule is unlikely to result in significant changes in firms' production decisions or other behavioral changes, and thus unlikely to result in significant changes in prices or quantities in affected markets. Thus, EPA followed its *Guidelines for Preparing Economic Analyses* (EPA, 2002, p.124–125) and used the engineering cost estimates to measure the social cost of the rule, rather than modeling market responses and using the resulting measures of social cost. Table VII–4 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE VII–4—ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES

NAICS	NAICS description	Average cost per entity (\$1,000/entity)	Average entity cost-to-sales ratio <sup>1</sup> (percent)
211	Oil and Gas Extraction	\$2	<0.1
221	SF6 from Electrical Systems	5	<0.1
322	Pulp & Paper Manufacturing	20	<0.1
324	Petroleum and Coal Products	21	<0.1
325	Chemical Manufacturing	14	<0.1
327	Cement & Other Mineral Production	50	0.8
331	Primary Metal Manufacturing	26	<0.1
486	Oil & Natural Gas Transportation	4	<0.1
562	Waste Management and Remediation Services	5	0.2
325199	Adipic Acid	24	<0.1
325311	Ammonia	17	<0.1
327310	Cement	63	0.2
331112	Ferroalloys	9	<0.1
3272	Glass	8	<0.1
325120	Hydrogen Production	3	<0.1
331112	Iron and Steel	30	<0.1
3314	Lead Production	10	<0.1
327410	Lime Manufacturing	60	0.4
325311	Nitric Acid	20	<0.1
324110	Petrochemical	27	<0.1
325312	Phosphoric Acid	60	<0.1
322110	Pulp and Paper	20	<0.1
324110	Refineries	41	<0.1
327910	Silicon Carbide	10	<0.1
3251	Soda Ash Manufacturing	16	<0.1
325188	Titanium Dioxide	10	<0.1
3314	Zinc Production	13	<0.1

<sup>1</sup> This ratio reflects first year costs. Subsequent year costs will be slightly lower because they do not include initial start-up activities.

2. Summary of Comments and Responses

*Comment:* EPA received a number of comments on the overall economic impacts of the proposed rule. Some commenters stated that the economic impacts are understated, as costs will not be passed on to consumers from

reporters. Other commenters stated that large increases in operating costs resulting from mandatory reporting of GHGs would lead facilities to close or move offshore.

*Response:* As described previously, EPA conducted a thorough analysis of available information and reviewed

comments submitted on this issue, and we have determined that this analysis provides a reasonable characterization of costs for facilities in each subpart and that the documentation provides adequate explanation of how the costs were estimated. Our economic impact analysis has been conducted without

taking into account the fact that some share of costs may be passed on to customers of each affected sector. Instead, facilities' annualized costs were compared to sales for entities in the sector, overall and for small entities. Even when all costs are absorbed by the facility, the costs represent less than one percent of sales and thus are not expected to result in significant hardship for affected firms.

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

1. Summary of Impacts on Small Businesses

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

EPA has determined the selected thresholds maximize the rule coverage with 81 to 86 percent of U.S. GHG emissions reported by approximately

10,152 reporters, while keeping reporting burden to a minimum and excluding small emitters. Furthermore, many industry stakeholders that EPA met with expressed support for a 25,000 metric ton CO<sub>2</sub>e threshold because it sufficiently captures the majority of GHG emissions in the U.S., while excluding smaller facilities and sources. For small facilities that are covered by the rule, EPA has included simplified emission estimation methods in the rule where feasible (e.g., stationary combustion equipment under a certain rating can use a simplified calculation approach as opposed to more rigorous direct monitoring) to keep the burden of reporting as low as possible. We received many comments related to monitoring and reporting requirements in specific source categories, and made many changes in response to reduce burden on reporters. For information on these issues, refer to the discussion of each source category in this preamble and the relevant volume of "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments." For further detail on the rationale for

excluding small entities through threshold selection please see the Thresholds TSD (EPA-HQ-OAR-2008-0508-046) and Section III.C.3 of this preamble.

EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-specific receipts data for establishments owned by small businesses. This ratio constitutes a "sales" test that computes the annualized compliance costs of this rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., one percent or three percent).<sup>32</sup> The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed EPA to account for receipt differences between establishments owned by large and small businesses and differences in small business definitions across affected industries. The results of the screening assessment are shown in Table VII-5 of this preamble.

TABLE VII-5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE <sup>a</sup>

Industry	NAICS	NAICS description	SBA size standard (effective March 11, 2008)	Average cost per entity (\$1,000/entity)	All enterprises (percent)	Owned by enterprises with:					
						<20 employees <sup>f</sup> (percent)	20 to 99 employees (percent)	100 to 499 employees (percent)	500 to 749 employees (percent)	750 to 999 employees (percent)	1,000 to 1,499 employees (percent)
Oil and Gas Extraction.	211	Oil & gas extraction.	500 .....	\$2	0.0	0.2	0.0	0.0	0.0	0.0	0.0
SF6 from Electrical Systems.	221	Utilities .....	(b) .....	5	0.0	0.2	0.0	0.0	0.0	0.0	0.0
Pulp & Paper Manufacturing.	322	Paper mfg .....	500 to 750 ...	20	0.1	1.2	0.2	0.1	0.0	0.0	0.0
Petroleum and Coal Products.	324	Petroleum & coal products mfg.	(c) .....	21	0.0	0.6	0.1	0.1	0.0	0.2	0.0
Chemical Manufacturing.	325	Chemical mfg .....	500 to 1,000	14	0.0	0.7	0.1	0.0	0.0	0.0	0.0
Cement & Other Mineral Production.	327	Nonmetallic mineral product mfg.	500 to 1,000	50	0.8	4.8	0.9	0.5	0.4	0.5	0.4
Primary Metal Manufacturing.	331	Primary metal mfg	500 to 1,000	26	0.1	2.1	0.3	0.1	0.1	0.0	0.0
Oil & Natural Gas Transportation.	486	Pipeline transportation.	(d) .....	4	0.0	0.0	0.2	0.1	NA	NA	NA
Waste Management and Remediation Services.	562	Waste management & remediation services.	(e) .....	5	0.2	0.7	0.1	0.1	0.0	0.0	0.0
Adipic Acid .....	325199	All other basic organic chemical mfg.	1,000 .....	24	0.0	0.9	0.3	0.1	NA	0.0	NA
Ammonia .....	325311	Nitrogenous fertilizer mfg.	1,000 .....	17	0.1	0.9	0.5	NA	NA	NA	NA
Cement .....	327310	Cement mfg .....	750 .....	63	0.2	2.0	1.5	0.3	NA	NA	0.1
Ferroalloys .....	331112	Electrometallurgical ferroalloy product mfg.	750 .....	9	0.0	NA	NA	NA	NA	NA	NA
Glass .....	3272	Glass & glass product mfg.	500 to 1,000	8	0.1	1.4	0.2	0.0	0.0	0.1	0.0
Hydrogen Production.	325120	Industrial gas mfg	1,000 .....	3	0.0	0.6	0.0	0.1	NA	NA	NA

<sup>32</sup> EPA's RFA guidance for rule writers suggests the "sales" test continues to be the preferred

quantitative metric for economic impact screening analysis.

TABLE VII-5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE <sup>a</sup>—Continued

Industry	NAICS	NAICS description	SBA size standard (effective March 11, 2008)	Average cost per entity (\$1,000/entity)	All enterprises (percent)	Owned by enterprises with:					
						<20 employees <sup>f</sup> (percent)	20 to 99 employees (percent)	100 to 499 employees (percent)	500 to 749 employees (percent)	750 to 999 employees (percent)	1,000 to 1,499 employees (percent)
Iron and Steel .....	331112	Electrometallurgical ferroalloy product mfg.	750 .....	30	0.1	NA	NA	NA	NA	NA	NA
Lead Production ....	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	10	0.0	0.6	0.1	0.0	NA	NA	0.0
Lime Manufacturing.	327410	Lime mfg .....	500 .....	60	0.4	16.5	1.2	NA	NA	NA	NA
Nitric Acid .....	325311	Nitrogenous fertilizer mfg.	1,000 .....	20	0.1	1.0	0.6	NA	NA	NA	NA
Petrochemical .....	324110	Petroleum refineries.	( <sup>c</sup> ) .....	27	0.0	0.4	0.0	0.0	0.0	NA	NA
Phosphoric Acid ....	325312	Phosphatic fertilizer mfg.	500 .....	60	0.1	10.1	NA	NA	NA	NA	NA
Pulp and Paper ....	322110	Pulp mills .....	750 .....	20	0.0	1.4	NA	NA	NA	NA	NA
Refineries .....	324110	Petroleum refineries.	( <sup>c</sup> ) .....	41	0.0	0.6	0.0	0.0	0.0	NA	NA
Silicon Carbide .....	327910	Abrasive product mfg.	500 .....	10	0.1	0.8	0.2	0.1	NA	NA	NA
Soda Ash Manufacturing.	3251	Basic chemical mfg.	500 to 1,000	16	0.0	0.5	0.1	0.0	0.0	0.0	0.0
Titanium Dioxide ...	325188	All other basic inorganic chemical mfg.	1,000 .....	10	0.0	0.7	0.4	0.1	NA	NA	NA
Zinc Production ....	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	13	0.1	0.9	0.1	0.0	NA	NA	0.0

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

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

<sup>b</sup> NAICS codes 221111, 221112, 221113, 221119, 221121, 221122—A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed four million MW hours.

<sup>c</sup> 500 to 1,500. For NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks.

<sup>d</sup> NAICS codes 486110 = 1,500 employees; NAICS 486210 = \$6.5 million annual receipts; NAICS 486910 = 1,500 employees; and NAICS 486990 = \$11.5 million annual receipts.

<sup>e</sup> Ranges from \$6.5 to \$13.0 million annual receipts; Environmental Remediation services has a 500 employee definition and the following criteria. NAICS 562910—Environmental Remediation Services:

(1) For SBA assistance as a small business concern in the industry of Environmental Remediation Services, other than for Government procurement, a concern must be engaged primarily in furnishing a range of services for the remediation of a contaminated environment to an acceptable condition including, but not limited to, preliminary assessment, site inspection, testing, remedial investigation, feasibility studies, remedial design, containment, remedial action, removal of contaminated materials, storage of contaminated materials and security and site closeouts. If one of such activities accounts for 50 percent or more of a concern's total revenues, employees, or other related factors, the concern's primary industry is that of the particular industry and not the Environmental Remediation Services Industry.

(2) For purposes of classifying a Government procurement as Environmental Remediation Services, the general purpose of the procurement must be to restore a contaminated environment and also the procurement must be composed of activities in three or more separate industries with separate NAICS codes or, in some instances (e.g., engineering), smaller sub-components of NAICS codes with separate, distinct size standards. These activities may include, but are not limited to, separate activities in industries such as: Heavy Construction; Special Trade Construction; Engineering Services; Architectural Services; Management Services; Refuse Systems; Sanitary Services, Not Elsewhere Classified; Local Trucking Without Storage; Testing Laboratories; and Commercial, Physical and Biological Research. If any activity in the procurement can be identified with a separate NAICS code, or component of a code with a separate distinct size standard, and that industry accounts for 50 percent or more of the value of the entire procurement, then the proper size standard is the one for that particular industry, and not the Environmental Remediation Service size standard.

<sup>f</sup> Given the Agency's selected thresholds, enterprises with fewer than 20 employees are likely to be excluded from the reporting program.

NA: Not available. SUSB did not report the data necessary to calculate this ratio.

EPA was not able to calculate a cost-to-sales ratio for manure management (NAICS 112) as Statistics of U.S. Businesses ([SUSB]SBA, 2008a) data do not provide establishment information for agricultural NAICS codes (e.g., NAICS 112 which covers manure management). EPA estimates that the total first year reporting costs for the entire manure management industry to

be \$0.3 million with an average cost per ton of CO<sub>2</sub>e reported of \$0.07.

As shown, the cost-to-sales ratios are less than one percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by businesses with 20 or more employees).

EPA acknowledges that several enterprise categories have ratios that

exceed this threshold (e.g., enterprise with one to 20 employees). EPA took a conservative approach with the model entity analysis. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a model establishment within several enterprise size ranges. To assess the likelihood that

these small businesses will be covered by the rule, we performed several case studies for manufacturing industries where the cost-to-receipt ratio exceeded one percent. For each industry, we used and applied emission data from a recent study examining emission thresholds<sup>33</sup>. This study provides industry-average CO<sub>2</sub> emission rates (e.g., tons per employee) for these manufacturing industries.

The case studies showed two industries (cement and lime manufacturing) where emission rates suggest small businesses of this employment size could potentially be covered by the rule. As a result, EPA examined corporate structures and ultimate parent companies were identified using industry surveys and the latest private databases such as Dun & Bradstreet. The results of this analysis show cost to sales ratios below one percent.

For the other enterprise categories identified with ratios between one percent and three percent EPA examined industry specific bottom up databases and previous industry specific studies to ensure that no entities with less than 20 employees are captured under the rule.

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

Additional analysis for a model small government also showed that the annualized reporting program costs were less than one percent of revenue. These impacts are likely representative of ratios in industries where data limitations do not allow EPA to

compute sales tests (e.g., general stationary combustion and manure management). Potential impacts of the rule on small governments were assessed separately from impacts on Federal Agencies. Small governments and small non-profit organizations may be affected if they own affected stationary combustion sources, landfills, or natural gas suppliers. However, the estimated costs under the rule are estimated to be small enough that no small government or small non-profit is estimated to incur significant impacts. For example, from the 2002 Census (in 2006), revenues for small governments (counties and municipalities) with populations fewer than 10,000 are \$3 million, and revenues for local governments with populations less than 50,000 is \$7 million. As an upper bound estimate, summing typical per-respondent costs of combustion plus landfills plus natural gas suppliers yields a cost of approximately \$18,000 per local government. Thus, for the smallest group of local governments (<10,000 people), cost-to-revenue ratio is 0.7 percent. For the larger group of governments less than 50,000, the cost-to-revenue ratio is 0.2 percent.

## 2. Summary of Comments and Responses

*Comment:* Comments received on small business impacts focused on the economic burden to small businesses for compliance with mandatory GHG reporting. One commenter noted that lowering the reporting threshold below the proposed 25,000 metric ton CO<sub>2</sub>e level would disproportionately affect small businesses. Another commenter stated that small businesses are not well equipped to handle detailed requirements for reporting and that the proposed rule would impose a large burden for monitoring, recordkeeping, and reporting activities.

Additional comments received requested that EPA establish a SBREFA process to investigate the impacts that the proposed rule would have on small businesses.

*Response:* As summarized above, EPA investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. EPA recognized the additional burden placed on small entities at lower thresholds, and had retained the hybrid method for reporting that includes a 25,000 metric ton CO<sub>2</sub>e level threshold. Under this threshold, EPA has assessed the economic impact of the final rule on small entities and concluded that this action will not have a significant

economic impact on a substantial number of small entities.

For this reason, EPA did not establish a SBREFA panel process for the rulemaking. The summary of the factual basis for the certification is provided in the preamble for the rule. Complete documentation of the analysis can be found in Section 5.2 of the RIA for the final rule.

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

### 1. Summary of Method Used To Estimate Compliance Costs

EPA examined the potential benefits of the GHG reporting rule. The benefits of a reporting system are based on their relevance to policy making, transparency issues, and market efficiency. Benefits are very difficult to quantify and monetize. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

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

The greatest benefit of mandatory reporting of industry GHG emissions to government will be realized in developing future GHG policies. For example, in the EU's Emissions Trading System, a lack of accurate monitoring at the facility level before establishing CO<sub>2</sub> allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

Benefits to industry of GHG emissions monitoring include the value of having independent, verifiable data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. Such monitoring allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to achieve and

<sup>33</sup> Nicholas Institute for Environmental Policy Solutions, Duke University. 2008. Size Thresholds for Greenhouse Gas Regulation: Who Would be Affected by a 10,000-ton CO<sub>2</sub> Emissions Rule? Available at: <http://www.nicholas.duke.edu/institute/10Kton.pdf>.

disseminate their environmental achievements.

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

## 2. Summary of Comments and Responses

*Comment:* Comments received on the benefits of the mandatory reporting program focused on the potential future uses of the collected data. Additional comments on the benefits of the program were concerned that the benefits of the rule are not quantified.

*Response:* The data collected under this rule will provide comprehensive and accurate data to inform future climate change policies. Potential future CAA and other climate policies include research and development initiatives, economic incentives, new or expanded voluntary programs, adaptation strategies, emission standards, a carbon tax, or a cap-and-trade program. Because EPA does not know at this time the specific policies that may be adopted, the data reported through this rule should be of sufficient quality to support a range of approaches.

Section VI of the RIA for the final rule summarizes the anticipated benefits of the rule, which include providing the government with sound data on which to base future policies and providing industry and the public independently verified information documenting firms' environmental performance. While EPA has not quantified the benefits of the mandatory reporting rule, EPA believes that they are substantial and outweigh the estimated costs.

## VIII. Statutory and Executive Order Reviews

### A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of EO 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of \$100 million or more. Accordingly, EPA submitted this action to the OMB for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits

associated with this action. A copy of the analysis is available in Docket No. EPA-HQ-OAR-2008-0508, the RIA for the final rule, and is briefly summarized in Section VII of this preamble.

### B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them. The ICR document prepared by EPA has been assigned EPA ICR number 2300.03.

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

This information collection is mandatory and will be carried out under CAA sections 114 and 208. Information identified and marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. However, emissions data collected under CAA sections 114 and 208 cannot generally be claimed as CBI and will be made public.<sup>34</sup>

The projected cost and hour burden for non-Federal respondents is \$86.3 million and 1.21 million hours per year. The estimated average burden per response is two hours; the frequency of response is annual for all respondents

<sup>34</sup> Although CBI determinations are usually made on a case-by-case basis, EPA has issued guidance in an earlier *Federal Register* notice on what constitutes emissions data that cannot be considered CBI (956 FR 7042-7043, February 21, 1991). As discussed in Section II.R of this preamble, EPA will be initiating a separate notice and comment process to make CBI determinations for the data collected under this rulemaking.

that must comply with the rule's reporting requirements, except for electricity generating units that are already required to report quarterly under 40 CFR part 75 (EPA Acid Rain Program); and the estimated average number of likely respondents per year is 16,725<sup>35</sup>. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (averaging \$9.1 million), a total operation and maintenance component (averaging \$11.0 million per year), and a labor cost component (averaging \$66.1 million per year). Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the RIA for the final rule because the ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the RIA for the final rule for the first year of the rule and for subsequent years of the rule. In addition, the ICR focuses on respondent burden, while the RIA for the final rule includes EPA Agency costs.

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

### C. Regulatory Flexibility Act (RFA)

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

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business

<sup>35</sup> EPA estimates that 30,000 facilities are potentially affected by the rule. Of these, EPA estimates that 10,152 facilities across various sectors will be over their sector-specific reporting threshold and thus required to report; the remaining 19,848 will determine during the first year that they are beneath the threshold and do not need to report. The average number of respondents is thus  $(30,000+10,152+10,152)/3 = 16,768$ ; excluding 43 Federal facilities, the number of private respondents is 16,725.

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

The small entities directly regulated by this final rule include small businesses across all sectors encompassed by the rule, small governmental jurisdictions and small non-profits. We have determined that some small businesses will be affected because their production processes emit GHGs that must be reported, because they have stationary combustion units on site that emit GHGs that must be reported, or because they have fuel supplier operations for which supply quantities and GHG data must be reported. Small governments and small non-profits are generally affected because they have regulated landfills or stationary combustion units on site, or because they own an LDC.

For affected small entities, EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-specific data on revenues for small businesses. This ratio constitutes a "sales" test that computes the annualized compliance costs of this final rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., one percent or three percent). The cost-to-sales ratios were constructed at the establishment level (average compliance cost for the establishment/average establishment revenues). As shown in Table VII-5 of this preamble, the cost-to-sales ratios are less than one percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program, those with more than 20 employees.<sup>36</sup> For the few sectors where the preliminary screening showed a cost-to-sales ratio exceeding one percent, EPA's examination of firm-specific sales information showed that no affected entity was likely to incur costs exceeding one percent of sales.

The screening analysis thus indicates that the final rule will not have a significant economic impact on a substantial number of small entities. See Table VII-5 of this preamble for sector-specific results. The screening assessment for small governments compared the sum of average costs of compliance for combustion, local distribution companies, and landfills to average revenues for small governments. Even for a small government owning all three source types, the costs constitute less than one percent of average revenues for the smallest category of governments (those with fewer than 10,000 people).

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA is not requiring facilities to install CEMS if they do 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 is requiring annual instead of more frequent reporting.

Through comprehensive outreach activities prior to proposal of the rule, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries that include small business members. EPA's outreach activities prior to proposal of the rule are documented in the memorandum, "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," located in Docket No. EPA-HQ-OAR-2008-0508-055. After proposal, EPA posted a guide for small businesses on EPA's GHG reporting rule Web site, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline to answer questions about the proposed rule. We continued to meet with stakeholders and entered documentation of all meetings into the docket. We considered public comments, including comments from small businesses and organizations that include small business members, in developing the final rule.

During rule implementation, EPA will maintain an "open door" policy for stakeholders to ask questions about the

rule or provide suggestions to EPA about the types of compliance assistance that would be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for the final rule.

#### *D. Unfunded Mandates Reform Act (UMRA)*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531-1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector.

EPA has developed this regulation under authority of CAA sections 114 and 208. The required activities under this Federal mandate include monitoring, recordkeeping, and reporting of GHG emissions from multiple source categories (e.g., combustion, process, and biologic). This rule contains a Federal mandate that may result in expenditures of \$100 million for the private sector in any one year. As described below, we have determined that the expenditures for State, local, and Tribal governments, in the aggregate, will be approximately \$12.1 million per year, based on average costs over the first three years of the rule, including approximately \$2 million during the first year of the rule for governments to make a reporting determination and subsequently determine that their emissions are below the threshold and thus, they are not required to report their emissions. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized below.

Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA initiated an outreach effort with the governmental entities affected by this rule including State, local, and Tribal officials. EPA maintained an "open door" policy for stakeholders to provide input on key issues and to help inform EPA's understanding of issues, including impacts to State, local and Tribal governments. The outreach audience included State environmental protection agencies, regional and Tribal organizations, and other State and local government organizations. EPA contacted several States and State and regional organizations already involved in GHG emissions reporting. EPA also conducted several conference calls with Tribal organizations during the proposal phase. For example, EPA staff provided information to tribes through conference calls with multiple Tribal working groups and organizations at EPA and

<sup>36</sup> U.S. Small Business Administration (SBA). 2008. Firm Size Data from the Statistics of U.S. Businesses: U.S. Detail Employment Sizes: 2002. [http://www.census.gov/csd/susb/download\\_susb02.htm](http://www.census.gov/csd/susb/download_susb02.htm).

through individual calls with two Tribal board members of TRI. In addition, EPA held meetings and conference calls with groups such as TRI, National Association of Clean Air Agencies (NACAA), ECOS, and with State members of RGGI, the Midwestern GHG Reduction Accord, and WCI. See the "Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule," in Docket No. EPA-HQ-OAR-2008-0508-055 for a complete list of organizations and groups that EPA contacted.

At proposal of the rule, EPA posted a guide for State and local agencies on the Web site, along with other information sheets, to communicate key aspects of the proposed rule to these agencies. Several State and local agencies and three Tribal organizations or communities submitted written public comments, and EPA carefully considered these comments in developing the final rule. EPA also continued to meet with government agencies or organizations with State members such as California ARB, Connecticut DEP, New Jersey DEP, New Mexico ED, Washington DE, Massachusetts DEP, Illinois EPA, Iowa DNR, and TCR. These meetings are documented in the docket. EPA intends to continue to work closely with State, local, and Tribal agencies during rule implementation.

Consistent with section 205 of the UMRA, EPA has identified and considered a reasonable number of regulatory alternatives. EPA carefully examined regulatory alternatives, and selected the lowest cost/least burdensome alternative that EPA deems adequate to address Congressional concerns and to provide a consistent, comprehensive source of information about emissions of GHGs. EPA has considered the costs and benefits of the GHG reporting rule, and has concluded that the costs will fall mainly on the private sector (approximately \$77 million), with some costs incurred by State, local, and Tribal governments that must report their emissions (less than \$10.1 million) that own and operate stationary combustion units, landfills, or natural gas local distribution companies (LDCs). EPA estimates that an additional 2,034 facilities owned by State, local, or Tribal governments will incur approximately \$2.0 million in costs during the first year of the rule to make a reporting determination and subsequently determine that their emissions are below the threshold and thus, they are not required to report their emissions. Furthermore, we think it is unlikely that State, local, and Tribal governments would begin operating

large industrial facilities, similar to those affected by this rulemaking operated by the private sector.

Initially, EPA estimates that costs of complying with the final rule will be widely dispersed throughout many sectors of the economy. Although EPA acknowledges that over time changes in the patterns of economic activity may mean that GHG generation and thus reporting costs will change, data are inadequate for projecting these changes. Thus, EPA assumes that costs averaged over the first three years of the program are typical of ongoing costs of compliance. EPA estimates that future compliance costs will total approximately \$104 million per year. EPA examined the distribution of these costs between private owners and State, local, and Tribal governments owning GHG emitters. In addition, EPA examined, within the private sector, the impacts on various industries. In general, estimated cost per entity represents less than 0.1 percent of company sales in affected industries. These costs are broadly distributed to a variety of economic sectors and represent approximately 0.001 percent of 2008 Gross Domestic Product; overall, EPA does not believe the final rule will have a significant macroeconomic impact on the national economy. Therefore, this rule is 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 does not anticipate that substantial numbers of either public or private sector entities will incur significant economic impacts as a result of this final rule. EPA further expects that benefits of the final rule will include more and better information for EPA and the private sector about emissions of GHGs. This improved information will enhance EPA's ability to develop sound future climate policies, and may encourage GHG emitters to develop voluntary plans to reduce their emissions.

This regulation applies directly to facilities that supply fuel or chemicals that when used emit greenhouse gases, to motor vehicle manufacturers, and to facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility that directly emits GHGs above threshold levels such as a landfill or large stationary combustion source, or LDC. In addition, this rule does not impose any implementation responsibilities on State, local, or Tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those

governments. Thus, the impact on governments affected by the rule is expected to be minimal.

#### *E. Executive Order 13132: Federalism*

EO 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications." "Policies that have Federalism implications" is defined in the EO to include regulations that 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."

This final rule 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 EO 13132. However, for a more detailed discussion about how this final rule relates to existing State programs, *please see* Section II of the proposal preamble (74 FR 16457 to 16461, April 10, 2009) and Sections I.E. and II.C.2 of this preamble.

This regulation applies directly to facilities that supply fuel or chemicals that when used emit greenhouse gases, motor vehicle manufacturers, or facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility that directly emits GHGs above threshold levels such as a landfill, large stationary combustion source, or LDC, so relatively few government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comments on the proposed rule from State and local officials. See Section VIII.D above, for discussion of outreach activities to State, local, or Tribal organizations.

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

This final rule does not have Tribal implications, as specified in EO 13175 (65 FR 67249, November 9, 2000). This

regulation applies directly to facilities that supply fuel or chemicals that when used emit GHGs or facilities that directly emit greenhouses gases. Facilities expected to be affected by the final rule are not expected to be owned by Tribal governments. Thus, Executive Order 13175 does not apply to this final rule.

Although EO 13175 does not apply to this final rule, EPA sought opportunities to provide information to Tribal governments and representatives during development of the rule. In consultation with EPA's American Indian Environment Office, EPA's outreach plan included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase. For example, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page a Tribal newsletter—Tribal Air News—that was distributed to EPA/OAQPS's network of Tribal organizations. EPA gave a presentation on various climate efforts, including the mandatory reporting rule, at the National Tribal Conference on Environmental Management on June 24–26, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. See the “Summary of EPA Outreach Activities for Developing the GHG reporting rule,” in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of Tribal contacts. EPA participated in a conference call with Tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the proposed rule. It was posted on the MRR Web site and published in the Tribal Air Newsletter.

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

#### *I. National Technology Transfer and Advancement Act*

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA will use more than 60 voluntary consensus standards from 10 different voluntary consensus standards bodies, including the following: ASTM, ASME, ISO, Gas Processors Association, American Gas Association, and National Lime Association. These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions. No new test methods were developed for this rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records of GHG emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products. The test methods are

incorporated by reference into the final rule and are available as specified in 40 CFR 98.7.

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

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

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

EPA has determined that this final 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. This final rule does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

#### *K. Congressional Review Act*

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a “major rule” as defined by 5 U.S.C. 804(2). This rule will be effective December 29, 2009.

#### **List of Subjects**

##### *40 CFR Part 86*

Environmental protection, Administrative practice and procedure,

Air pollution control, Reporting and recordkeeping requirements, Motor vehicle pollution.

**40 CFR Part 87**

Environmental protection, Air pollution control, Aircraft, Incorporation by reference.

**40 CFR Part 89**

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Vessels, Warranty.

**40 CFR Part 90**

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Reporting and recordkeeping requirements, Research, Warranty.

**40 CFR Part 94**

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

**40 CFR Part 98**

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

**40 CFR Part 1033**

Environmental protection, Administrative practice and procedure, Confidential business information, Incorporation by reference, Labeling, Penalties, Railroads, Reporting and recordkeeping requirements.

**40 CFR Part 1039**

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

**40 CFR Part 1042**

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

*40 CFR Parts 1045, 1048, 1051, and 1054*

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

**40 CFR Part 1065**

Environmental protection, Administrative practice and procedure, Incorporation by reference, Reporting and recordkeeping requirements, Research.

Dated: September 22, 2009.

**Lisa P. Jackson,**  
*Administrator.*

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

**PART 86—[AMENDED]**

■ 1. The authority citation for part 86 continues to read as follows:

**Authority:** 42 U.S.C. 7401–7671q.

**Subpart A—[Amended]**

■ 2. Section 86.007–23 is amended by adding paragraph (n) to read as follows:

**§ 86.007–23 Required data.**

\* \* \* \* \*

(n) Measure CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> with each low-hour certification test for heavy-duty engines using the procedures specified in 40 CFR part 1065 as specified in this paragraph (n). Report these values in your application for certification. The requirements of this paragraph (n) apply starting with model year 2011 for CO<sub>2</sub> and 2012 for CH<sub>4</sub>. The requirements of this paragraph (n) related to N<sub>2</sub>O emissions apply for engine families that depend on NO<sub>x</sub> aftertreatment to meet emission standards starting with model year 2013. These measurements are not required for NTE testing. Use the same units and calculations as for your other results to report a single weighted value for CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> for each test. Round the final values as follows:

(1) Round CO<sub>2</sub> to the nearest 1 g/bhp-hr.

(2) Round N<sub>2</sub>O to the nearest 0.001 g/bhp-hr.

(3) Round CH<sub>4</sub> to the nearest 0.001 g/bhp-hr.

■ 3. Section 86.078–3 is amended by removing the paragraph designation “(a)” and adding the abbreviations CH<sub>4</sub> and N<sub>2</sub>O in alphanumeric order to read as follows:

**§ 86.078–3 Abbreviations.**

\* \* \* \* \*

\* \* \* \* \*

CH<sub>4</sub> methane.

\* \* \* \* \*

N<sub>2</sub>O nitrous oxide.

\* \* \* \* \*

**Subpart E—[Amended]**

■ 4. Section 86.403–78 is amended by adding the abbreviations CH<sub>4</sub> and N<sub>2</sub>O in alphanumeric order to read as follows:

**§ 86.403–78 Abbreviations.**

\* \* \* \* \*

\* \* \* \* \*

CH<sub>4</sub> methane.

\* \* \* \* \*

N<sub>2</sub>O nitrous oxide.

\* \* \* \* \*

■ 5. Section 86.431–78 is amended by adding paragraph (e) to read as follows:

**§ 86.431–78 Data submission.**

\* \* \* \* \*

(e) Measure CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> as described in this paragraph (e) with each zero kilometer certification test (if one is conducted) and with each test conducted at the applicable minimum test distance as defined in § 86.427–78. Use the analytical equipment and procedures specified in 40 CFR part 1065 as needed to measure N<sub>2</sub>O and CH<sub>4</sub>. Report these values in your application for certification. The requirements of this paragraph (e) apply starting with model year 2011 for CO<sub>2</sub> and 2012 for CH<sub>4</sub>. The requirements of this paragraph (e) related to N<sub>2</sub>O emissions apply for engine families that depend on NO<sub>x</sub> aftertreatment to meet emission standards starting with model year 2013. Small-volume manufacturers (as defined in § 86.410–2006(e)) may omit measurement of N<sub>2</sub>O and CH<sub>4</sub>; other manufacturers may provide appropriate data and/or information and omit measurement of N<sub>2</sub>O and CH<sub>4</sub> as described in 40 CFR 1065.5. Use the same measurement methods as for your other results to report a single value for CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub>. Round the final values as follows:

(1) Round CO<sub>2</sub> to the nearest 1 g/km.

(2) Round N<sub>2</sub>O to the nearest 0.001 g/km.

(3) Round CH<sub>4</sub> to the nearest 0.001 g/km.

**PART 87—[AMENDED]**

■ 6. The authority citation for part 87 is revised to read as follows:

**Authority:** 42 U.S.C. 7401–7671q.

**Subpart A—[Amended]**

■ 7. Section 87.2 is amended by revising the section heading and adding the abbreviation CO<sub>2</sub> in alphanumeric order to read as follows:

**§ 87.2 Acronyms and abbreviations.**

\* \* \* \* \*  
CO<sub>2</sub> Carbon dioxide.  
\* \* \* \* \*

■ 8. Section 87.64 is revised to read as follows:

**§ 87.64 Sampling and analytical procedures for measuring gaseous exhaust emissions.**

(a) The system and procedures for sampling and measurement of gaseous emissions shall be as specified by Appendices 3 and 5 to ICAO Annex 16 (incorporated by reference in § 87.8).

(b) Starting January 1, 2011, report CO<sub>2</sub> values along with your emission levels of regulated NO<sub>x</sub> to the Administrator for engines of a type or model of which the date of manufacture of the first individual production model was on or after January 1, 2011. By January 1, 2011, report CO<sub>2</sub> values along with your emission levels of regulated NO<sub>x</sub> to the Administrator for engines currently in production and of a type or model for which the date of manufacture of the individual engine was before January 1, 2011. Round CO<sub>2</sub> to the nearest 1 g/kilonewton rO.

(c) Report CO<sub>2</sub> by calculation from fuel mass flow rate measurements in Appendices 3 and 5 to ICAO Annex 16, volume II or alternatively, according to the measurement criteria of CO<sub>2</sub> in Appendices 3 and 5 to ICAO Annex 16, volume II.

**PART 89—[AMENDED]**

■ 9. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

**Subpart B—[Amended]**

■ 10. Section 89.115 is amended by revising paragraph (d)(9) to read as follows:

**§ 89.115 Application for certificate.**

\* \* \* \* \*  
(d) \* \* \*

(9) All test data obtained by the manufacturer on each test engine, including CO<sub>2</sub> as specified in § 89.407(d)(1);

\* \* \* \* \*

**Subpart E—[Amended]**

■ 11. Section 89.407 is amended by revising paragraph (d)(1) to read as follows:

**§ 89.407 Engine dynamometer test run.**

\* \* \* \* \*  
(d) \* \* \*

(1) Measure HC, CO, CO<sub>2</sub>, and NO<sub>x</sub> concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO<sub>2</sub>; round CO<sub>2</sub> to the nearest 1 g/kW-hr.

\* \* \* \* \*

**PART 90—[AMENDED]**

■ 12. The authority citation for part 90 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

**Subpart B—[Amended]**

■ 13. Section 90.107 is amended by revising paragraph (d)(8) to read as follows:

**§ 90.107 Application for certification.**

\* \* \* \* \*  
(d) \* \* \*

(8) All test data obtained by the manufacturer on each test engine, including CO<sub>2</sub> as specified in § 90.409(c)(1);

\* \* \* \* \*

**Subpart E—[Amended]**

■ 14. Section 90.409 is amended by revising paragraph (c)(1) to read as follows:

**§ 90.409 Engine dynamometer test run.**

\* \* \* \* \*  
(c) \* \* \*

(1) Measure HC, CO, CO<sub>2</sub>, and NO<sub>x</sub> concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO<sub>2</sub>; round CO<sub>2</sub> to the nearest 1 g/kW-hr.

\* \* \* \* \*

**PART 94—[AMENDED]**

■ 15. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

**Subpart A—[Amended]**

■ 16. Section 94.3 is amended by adding the abbreviation CH<sub>4</sub> in alphanumeric order to read as follows:

**§ 94.3 Abbreviations.**

\* \* \* \* \*  
CH<sub>4</sub> methane.

\* \* \* \* \*

**Subpart B—[Amended]**

■ 17. Section 94.103 is amended by adding paragraph (c) to read as follows:

**§ 94.103 Test procedures for Category 1 marine engines.**

\* \* \* \* \*

(c) Measure CH<sub>4</sub> as specified in 40 CFR 1042.235 starting in the 2012 model year.

■ 18. Section 94.104 is amended by adding paragraph (e) to read as follows:

**§ 94.104 Test procedures for Category 2 marine engines.**

\* \* \* \* \*

(e) Measure CO<sub>2</sub> as described in 40 CFR 92.129 through the 2010 model year. Measure CO<sub>2</sub> as specified in 40 CFR 1042.235 starting in the 2011 model year. Measure CH<sub>4</sub> as specified in 40 CFR 1042.235 starting in the 2012 model year.

**Subpart C—[Amended]**

■ 19. Section 94.203 is amended by revising paragraph (d)(10) to read as follows:

**§ 94.203 Application for certification.**

\* \* \* \* \*  
(d) \* \* \*

(10) All test data obtained by the manufacturer on each test engine, including CO<sub>2</sub> and CH<sub>4</sub> as specified in 40 CFR 89.407(d)(1) and § 94.103(c) for Category 1 engines, § 94.104(e) for Category 2 engines, and § 94.109(d) for Category 3 engines. Small-volume manufacturers may omit measurement and reporting of CH<sub>4</sub>.

\* \* \* \* \*

■ 20. Add part 98 to read as follows:

**PART 98—MANDATORY GREENHOUSE GAS REPORTING**

Sec.

**Subpart A—General Provisions**

- 98.1 Purpose and scope.
  - 98.2 Who must report?
  - 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?
  - 98.4 Authorization and responsibilities of the designated representative.
  - 98.5 How is the report submitted?
  - 98.6 Definitions.
  - 98.7 What standardized methods are incorporated by reference into this part?
  - 98.8 What are the compliance and enforcement provisions of this part?
  - 98.9 Addresses.
- Table A–1 to Subpart A of Part 98—Global Warming Potentials (100-Year Time Horizon)  
Table A–2 to Subpart A of Part 98—Units of Measure Conversions

**Subpart B—[RESERVED]****Subpart C—General Stationary Fuel Combustion Sources**

- 98.30 Definition of the source category.  
 98.31 Reporting threshold.  
 98.32 GHGs to report.  
 98.33 Calculating GHG emissions.  
 98.34 Monitoring and QA/QC requirements.  
 98.35 Procedures for estimating missing data.  
 98.36 Data reporting requirements.  
 98.37 Records that must be retained.  
 98.38 Definitions.  
 Table C-1 to Subpart C of Part 98—Default CO<sub>2</sub> Emission Factors and High Heat Values for Various Types of Fuel  
 Table C-2 to Subpart C of Part 98—Default CH<sub>4</sub> and N<sub>2</sub>O Emission Factors for Various Types of Fuel

**Subpart D—Electricity Generation**

- 98.40 Definition of the source category.  
 98.41 Reporting threshold.  
 98.42 GHGs to report.  
 98.43 Calculating GHG emissions.  
 98.44 Monitoring and QA/QC requirements  
 98.45 Procedures for estimating missing data.  
 98.46 Data reporting requirements.  
 98.47 Records that must be retained.  
 98.48 Definitions.

**Subpart E—Adipic Acid Production**

- 98.50 Definition of source category.  
 98.51 Reporting threshold.  
 98.52 GHGs to report.  
 98.53 Calculating GHG emissions.  
 98.54 Monitoring and QA/QC requirements  
 98.55 Procedures for estimating missing data.  
 98.56 Data reporting requirements.  
 98.57 Records that must be retained.  
 98.58 Definitions.

**Subpart F—Aluminum Production**

- 98.60 Definition of the source category.  
 98.61 Reporting threshold.  
 98.62 GHGs to report.  
 98.63 Calculating GHG emissions.  
 98.64 Monitoring and QA/QC requirements.  
 98.65 Procedures for estimating missing data.  
 98.66 Data reporting requirements.  
 98.67 Records that must be retained.  
 98.68 Definitions.  
 Table F-1 to Subpart F of Part 98—Slope and Overvoltage Coefficients for the Calculation of PFC Emissions From Aluminum Production  
 Table F-2 to Subpart F of Part 98—Default Data Sources for Parameters Used for CO<sub>2</sub> Emissions

**Subpart G—Ammonia Manufacturing**

- 98.70 Definition of source category.  
 98.71 Reporting threshold.  
 98.72 GHGs to report.  
 98.73 Calculating GHG emissions.  
 98.74 Monitoring and QA/QC requirements.  
 98.75 Procedures for estimating missing data.  
 98.76 Data reporting requirements.  
 98.77 Records that must be retained.

- 98.78 Definitions.

**Subpart H—Cement Production**

- 98.80 Definition of the source category.  
 98.81 Reporting threshold.  
 98.82 GHGs to report.  
 98.83 Calculating GHG emissions.  
 98.84 Monitoring and QA/QC requirements.  
 98.85 Procedures for estimating missing data.  
 98.86 Data reporting requirements.  
 98.87 Records that must be retained.  
 98.88 Definitions.

**Subpart I—[RESERVED]****Subpart J—[RESERVED]****Subpart K—Ferroalloy Production**

- 98.110 Definition of the source category.  
 98.111 Reporting threshold.  
 98.112 GHGs to report.  
 98.113 Calculating GHG emissions.  
 98.114 Monitoring and QA/QC requirements.  
 98.115 Procedures for estimating missing data.  
 98.116 Data reporting requirements.  
 98.117 Records that must be retained.  
 98.118 Definitions.  
 Table K-1 to Subpart K of Part 98—Electric Arc Furnace (EAF) CH<sub>4</sub> Emission Factors

**Subpart L—[RESERVED]****Subpart M—[RESERVED]****Subpart N—Glass Production**

- 98.140 Definition of the source category.  
 98.141 Reporting threshold.  
 98.142 GHGs to report.  
 98.143 Calculating GHG emissions.  
 98.144 Monitoring and QA/QC requirements.  
 98.145 Procedures for estimating missing data.  
 98.146 Data reporting requirements.  
 98.147 Records that must be retained.  
 98.148 Definitions.  
 Table N-1 to Subpart N of Part 98—CO<sub>2</sub> Emission Factors for Carbonate-Based Raw Materials

**Subpart O—HCFC-22 Production and HFC-23 Destruction**

- 98.150 Definition of the source category.  
 98.151 Reporting threshold.  
 98.152 GHGs to report.  
 98.153 Calculating GHG emissions.  
 98.154 Monitoring and QA/QC requirements.  
 98.155 Procedures for estimating missing data.  
 98.156 Data reporting requirements.  
 98.157 Records that must be retained.  
 98.158 Definitions.  
 Table O-1 to Subpart O of Part 98—Emission Factors for Equipment Leaks

**Subpart P—Hydrogen Production**

- 98.160 Definition of the source category.  
 98.161 Reporting threshold.  
 98.162 GHGs to report.  
 98.163 Calculating GHG emissions.  
 98.164 Monitoring and QA/QC requirements.  
 98.165 Procedures for estimating missing data.

- 98.166 Data reporting requirements.  
 98.167 Records that must be retained.  
 98.168 Definitions.

**Subpart Q—Iron and Steel Production**

- 98.170 Definition of the source category.  
 98.171 Reporting threshold.  
 98.172 GHGs to report.  
 98.173 Calculating GHG emissions.  
 98.174 Monitoring and QA/QC requirements.  
 98.175 Procedures for estimating missing data.  
 98.176 Data reporting requirements.  
 98.177 Records that must be retained.  
 98.178 Definitions.

**Subpart R—Lead Production**

- 98.180 Definition of the source category.  
 98.181 Reporting threshold.  
 98.182 GHGs to report.  
 98.183 Calculating GHG emissions.  
 98.184 Monitoring and QA/QC requirements.  
 98.185 Procedures for estimating missing data.  
 98.186 Data reporting procedures.  
 98.187 Records that must be retained.  
 98.188 Definitions.

**Subpart S—Lime Manufacturing**

- 98.190 Definition of the source category.  
 98.191 Reporting threshold.  
 98.192 GHGs to report.  
 98.193 Calculating GHG emissions.  
 98.194 Monitoring and QA/QC requirements.  
 98.195 Procedures for estimating missing data.  
 98.196 Data reporting requirements.  
 98.197 Records that must be retained.  
 98.198 Definitions.  
 Table S-1 to Subpart S of Part 98—Basic Parameters for the Calculation of Emission Factors for Lime Production

**Subpart T—[RESERVED]****Subpart U—Miscellaneous Uses of Carbonate**

- 98.210 Definition of the source category.  
 98.211 Reporting threshold.  
 98.212 GHGs to report.  
 98.213 Calculating GHG emissions.  
 98.214 Monitoring and QA/QC requirements.  
 98.215 Procedures for estimating missing data.  
 98.216 Data reporting requirements.  
 98.217 Records that must be retained.  
 98.218 Definitions.

**Table U-1 to Subpart U of Part 98—CO<sub>2</sub> Emission Factors for Common Carbonates****Subpart V—Nitric Acid Production**

- 98.220 Definition of source category.  
 98.221 Reporting threshold.  
 98.222 GHGs to report.  
 98.223 Calculating GHG emissions.  
 98.224 Monitoring and QA/QC requirements.  
 98.225 Procedures for estimating missing data.  
 98.226 Data reporting requirements.  
 98.227 Records that must be retained.  
 98.228 Definitions.

**Subpart W—[RESERVED]****Subpart X—Petrochemical Production**

- 98.240 Definition of the source category.
- 98.241 Reporting threshold.
- 98.242 GHGs to report.
- 98.243 Calculating GHG emissions.
- 98.244 Monitoring and QA/QC requirements.
- 98.245 Procedures for estimating missing data.
- 98.246 Data reporting requirements.
- 98.247 Records that must be retained.
- 98.248 Definitions.

**Subpart Y—Petroleum Refineries**

- 98.250 Definition of source category.
- 98.251 Reporting threshold.
- 98.252 GHGs to report.
- 98.253 Calculating GHG emissions.
- 98.254 Monitoring and QA/QC requirements.
- 98.255 Procedures for estimating missing data.
- 98.256 Data reporting requirements.
- 98.257 Records that must be retained.
- 98.258 Definitions.

**Subpart Z—Phosphoric Acid Production**

- 98.260 Definition of the source category.
- 98.261 Reporting threshold.
- 98.262 GHGs to report.
- 98.263 Calculating GHG emissions.
- 98.264 Monitoring and QA/QC requirements.
- 98.265 Procedures for estimating missing data.
- 98.266 Data reporting requirements.
- 98.267 Records that must be retained.
- 98.268 Definitions.

Table Z–1 to Subpart Z of Part 98—Default Chemical Composition of Phosphate Rock by Origin

**Subpart AA—Pulp and Paper Manufacturing**

- 98.270 Definition of source category.
- 98.271 Reporting threshold.
- 98.272 GHGs to report.
- 98.273 Calculating GHG emissions.
- 98.274 Monitoring and QA/QC requirements.
- 98.275 Procedures for estimating missing data.
- 98.276 Data reporting requirements.
- 98.277 Records that must be retained.
- 98.278 Definitions.

Table AA–1 to Subpart AA of Part 98—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O

Table AA–2 to Subpart AA of Part 98—Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O

**Subpart BB—Silicon Carbide Production**

- 98.280 Definition of the source category.
- 98.281 Reporting threshold.
- 98.282 GHGs to report.
- 98.283 Calculating GHG emissions.
- 98.284 Monitoring and QA/QC requirements.
- 98.285 Procedures for estimating missing data.
- 98.286 Data reporting requirements.
- 98.287 Records that must be retained.
- 98.288 Definitions.

**Subpart CC—Soda Ash Manufacturing**

- 98.290 Definition of the source category.
- 98.291 Reporting threshold.
- 98.292 GHGs to report.
- 98.293 Calculating GHG emissions.
- 98.294 Monitoring and QA/QC requirements.
- 98.295 Procedures for estimating missing data.
- 98.296 Data reporting requirements.
- 98.297 Records that must be retained.
- 98.298 Definitions.

**Subpart DD—[RESERVED]****Subpart EE—Titanium Dioxide Production**

- 98.310 Definition of the source category.
- 98.311 Reporting threshold.
- 98.312 GHGs to report.
- 98.313 Calculating GHG emissions.
- 98.314 Monitoring and QA/QC requirements.
- 98.315 Procedures for estimating missing data.
- 98.316 Data reporting requirements.
- 98.317 Records that must be retained.
- 98.318 Definitions.

**Subpart FF—[RESERVED]****Subpart GG—Zinc Production**

- 98.330 Definition of the source category.
- 98.331 Reporting threshold.
- 98.332 GHGs to report.
- 98.333 Calculating GHG emissions.
- 98.334 Monitoring and QA/QC requirements.
- 98.335 Procedures for estimating missing data.
- 98.336 Data reporting requirements.
- 98.337 Records that must be retained.
- 98.338 Definitions.

**Subpart HH—Municipal Solid Waste Landfills**

- 98.340 Definition of the source category.
- 98.341 Reporting threshold.
- 98.342 GHGs to report.
- 98.343 Calculating GHG emissions.
- 98.344 Monitoring and QA/QC requirements.
- 98.345 Procedures for estimating missing data.
- 98.346 Data reporting requirements.
- 98.347 Records that must be retained.
- 98.348 Definitions.

Table HH–1 to Subpart HH of Part 98—Emissions Factors, Oxidation Factors and Methods

Table HH–2 to Subpart HH of Part 98—U.S. Per Capita Waste Disposal Rates

Table HH–3 to Subpart HH of Part 98—Landfill Gas Collection Efficiencies

**Subpart II—[RESERVED]****Subpart JJ—Manure Management**

- 98.360 Definition of the source category.
- 98.361 Reporting threshold.
- 98.362 GHGs to report.
- 98.363 Calculating GHG emissions.
- 98.364 Monitoring and QA/QC requirements.
- 98.365 Procedures for estimating missing data.
- 98.366 Data reporting requirements.
- 98.367 Records that must be retained.
- 98.368 Definitions.

Table JJ–1 to Subpart JJ of Part 98—Animal Population Threshold Level Below which Facilities are not required to report Emissions under Subpart JJ

Table JJ–2 to Subpart JJ of Part 98—Waste Characteristics Data

Table JJ–3 to Subpart JJ of Part 98—State-Specific Volatile Solids (VS) and Nitrogen (N) Excretion Rates for Cattle

Table JJ–4 to Subpart JJ of Part 98—Volatile Solids and Nitrogen Removal through Solids Separation

Table JJ–5 to Subpart JJ of Part 98—Methane Conversion Factors

Table JJ–6 to Subpart JJ of Part 98—Collection Efficiencies of Anaerobic Digesters

Table JJ–7 to Subpart JJ of Part 98—Nitrous Oxide Emission Factors (kg N<sub>2</sub>O–N/kg Kjdl N)

**Subpart KK—[RESERVED]****Subpart LL—Suppliers of Coal-based Liquid Fuels**

- 98.380 Definition of the source category.
- 98.381 Reporting threshold.
- 98.382 GHGs to report.
- 98.383 Calculating GHG emissions.
- 98.384 Monitoring and QA/QC requirements.
- 98.385 Procedures for estimating missing data.
- 98.386 Data reporting requirements.
- 98.387 Records that must be retained.
- 98.388 Definitions.

**Subpart MM—Suppliers of Petroleum Products**

- 98.390 Definition of the source category.
- 98.391 Reporting threshold.
- 98.392 GHGs to report.
- 98.393 Calculating GHG emissions.
- 98.394 Monitoring and QA/QC requirements.
- 98.395 Procedures for estimating missing data.
- 98.396 Data reporting requirements.
- 98.397 Records that must be retained.
- 98.398 Definitions.

Table MM–1 to Subpart MM—Default CO<sub>2</sub> Factors for Petroleum Products

Table MM–2 to Subpart MM—Default Factors for Biomass-Based Fuels and Biomass

**Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids**

- 98.400 Definition of the source category.
- 98.401 Reporting threshold.
- 98.402 GHGs to report.
- 98.403 Calculating GHG emissions.
- 98.404 Monitoring and QA/QC requirements.
- 98.405 Procedures for estimating missing data.
- 98.406 Data reporting requirements.
- 98.407 Records that must be retained.
- 98.408 Definitions.

Table NN–1 to Subpart NN of Part 98—Default Factors for Calculation

Methodology 1 of this Subpart

Table NN–2 to Subpart NN of Part 98—Lookup Default Values for Calculation Methodology 2 of this Subpart

**Subpart OO—Suppliers of Industrial Greenhouse Gases**

- 98.410 Definition of the source category.

- 98.411 Reporting threshold.  
 98.412 GHGs to report.  
 98.413 Calculating GHG emissions.  
 98.414 Monitoring and QA/QC requirements.  
 98.415 Procedures for estimating missing data.  
 98.416 Data reporting requirements.  
 98.417 Records that must be retained.  
 98.418 Definitions.

#### Subpart PP—Suppliers of Carbon Dioxide

- 98.420 Definition of the source category.  
 98.421 Reporting threshold.  
 98.422 GHGs to report.  
 98.423 Calculating CO<sub>2</sub> supply.  
 98.424 Monitoring and QA/QC requirements.  
 98.425 Procedures for estimating missing data.  
 98.426 Data reporting requirements.  
 98.427 Records that must be retained.  
 98.428 Definitions.

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

#### Subpart A—General Provisions

##### § 98.1 Purpose and scope.

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

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

##### § 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(1) in any calendar year starting in 2010. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

(i) Electricity generation (units that report CO<sub>2</sub> emissions year-round through 40 CFR part 75).

- (ii) Adipic acid production.  
 (iii) Aluminum production.  
 (iv) Ammonia manufacturing.  
 (v) Cement production.  
 (vi) HCFC–22 production.  
 (vii) HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.  
 (viii) Lime manufacturing.  
 (ix) Nitric acid production.  
 (x) Petrochemical production.  
 (xi) Petroleum refineries.  
 (xii) Phosphoric acid production.  
 (xiii) Silicon carbide production.  
 (xiv) Soda ash production.  
 (xv) Titanium dioxide production.  
 (xvi) Municipal solid waste landfills that generate CH<sub>4</sub> in amounts equivalent to 25,000 metric tons CO<sub>2</sub>e or more per year, as determined according to subpart HH of this part.

(xvii) Manure management systems with combined CH<sub>4</sub> and N<sub>2</sub>O emissions in amounts equivalent to 25,000 metric tons CO<sub>2</sub>e or more per year, as determined according to subpart JJ of this part.

(2) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(2) in any calendar year starting in 2010 and that emits 25,000 metric tons CO<sub>2</sub>e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this paragraph. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

- (i) Ferroalloy Production.  
 (ii) Glass Production.  
 (iii) Hydrogen Production.  
 (iv) Iron and Steel Production.  
 (v) Lead Production.  
 (vi) Pulp and Paper Manufacturing.  
 (vii) Zinc Production.  
 (3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

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

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

(iii) The facility emits 25,000 metric tons CO<sub>2</sub>e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier (as defined in subparts KK through PP of this part) that

provides products listed in this paragraph (a)(4) in any calendar year starting in 2010. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in subparts KK through PP of this part.

(i) Coal-to-liquids suppliers, as specified in this paragraph (a)(4)(i).

(A) All producers of coal-to-liquid products.

(B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(C) Exporters of an annual quantity of coal-to-liquid products is equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(ii) Petroleum product suppliers, as specified in this paragraph (a)(4)(ii):

(A) All petroleum refineries that distill crude oil.

(B) Importers of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(C) Exporters of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(iii) Natural gas and natural gas liquids suppliers, as specified in this paragraph (a)(4)(iii):

(A) All natural gas fractionators.

(B) All local natural gas distribution companies.

(iv) Industrial greenhouse gas suppliers, as specified in this paragraph (a)(4)(iv):

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse gases with annual bulk imports of N<sub>2</sub>O, fluorinated GHG, and CO<sub>2</sub> that in combination are equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(C) Exporters of industrial greenhouse gases with annual bulk exports of N<sub>2</sub>O, fluorinated GHG, and CO<sub>2</sub> that in combination are equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(v) Carbon dioxide suppliers, as specified in this paragraph (a)(4)(v).

(A) All producers of CO<sub>2</sub>.

(B) Importers of CO<sub>2</sub> with annual bulk imports of N<sub>2</sub>O, fluorinated GHG, and CO<sub>2</sub> that in combination are equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

(C) Exporters of CO<sub>2</sub> with annual bulk exports of N<sub>2</sub>O, fluorinated GHG, and CO<sub>2</sub> that in combination are equivalent to 25,000 metric tons CO<sub>2</sub>e or more.

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

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO<sub>2</sub>e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual

CO<sub>2</sub>e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A-1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO<sub>2</sub> emissions in metric tons using any of the four calculation methodologies specified in § 98.33(a). Calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in § 98.33(c). Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH<sub>4</sub> and N<sub>2</sub>O from biomass combustion.

(3) For miscellaneous uses of carbonate, calculate the annual CO<sub>2</sub> emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO<sub>2</sub>e using Equation A-1 of this section.

$$\text{CO}_2\text{e} = \sum_{i=1}^n \text{GHG}_i \times \text{GWP}_i \quad (\text{Eq. A-1})$$

Where:

CO<sub>2</sub>e = Carbon dioxide equivalent, metric tons/year.

GHG<sub>i</sub> = Mass emissions of each greenhouse gas listed in Table A-1 of this subpart, metric tons/year.

GWP<sub>i</sub> = Global warming potential for each greenhouse gas from Table A-1 of this subpart.

n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO<sub>2</sub> that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO<sub>2</sub>e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO<sub>2</sub>e per year using Equation A-1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton

CO<sub>2</sub> per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4)(i) of this section, calculate the mass in metric tons per year of CO<sub>2</sub> that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO<sub>2</sub>e per year threshold for importers and exporters of petroleum products under paragraph (a)(4)(ii) of this section, calculate the mass in metric tons per year of CO<sub>2</sub> that would result from the complete combustion or oxidation of the volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO<sub>2</sub>e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO<sub>2</sub>, the owner or operator shall calculate the mass in metric tons per year of CO<sub>2</sub>e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section.

(1) Calculate the mass in metric tons per year of CO<sub>2</sub>, N<sub>2</sub>O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO<sub>2</sub>, N<sub>2</sub>O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A-1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO<sub>2</sub>e using Equation A-1 of this section.

(3) Sum the total annual metric tons of CO<sub>2</sub>e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO<sub>2</sub>e in paragraph (f)(2) of this section for all exported GHGs.

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

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting

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

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

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

(2) If reported emissions are less than 15,000 metric tons CO<sub>2</sub>e per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO<sub>2</sub>e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three

consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO<sub>2e</sub> per year or more.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraphs (a)(1) through (a)(4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations. This paragraph (i)(2) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(2) does not apply to facilities with municipal solid waste landfills. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

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

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

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

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

(b) *Schedule.* The annual GHG report must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For an existing facility or supplier that began operation before January 1, 2010, report emissions for calendar year 2010 and each subsequent calendar year.

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

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

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

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

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, report annual emissions of CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, and each fluorinated GHG (as defined in § 98.6) as follows:

(i) Annual emissions (excluding biogenic CO<sub>2</sub>) aggregated for all GHG from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO<sub>2e</sub> calculated using Equation A-1 of this subpart.

(ii) Annual emissions of biogenic CO<sub>2</sub> aggregated for all applicable source categories in subparts C through JJ of this part.

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

(A) Biogenic CO<sub>2</sub>.

(B) CO<sub>2</sub> (excluding biogenic CO<sub>2</sub>).

(C) CH<sub>4</sub>.

(D) N<sub>2</sub>O.

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

(iv) Emissions and other data for individual units, processes, activities, and operations as specified in the "Data reporting requirements" section of each applicable subpart of this part.

(5) For suppliers, report annual quantities of CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, and each fluorinated GHG (as defined in § 98.6) that would be emitted from combustion or use of the products supplied,

imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO<sub>2e</sub> calculated using Equation A-1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in subparts KK through PP of this part, expressed in metric tons of each GHG. For fluorinated GHG, report emissions of all fluorinated GHG, including those not listed in Table A-1 of this subpart.

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

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

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

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

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

(d) Special provisions for reporting year 2010.

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

provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods.*

The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

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

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

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

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

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

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

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

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

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

(3) *Abbreviated emissions report for facilities containing only general stationary fuel combustion sources.* In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of § 98.2 (a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2011. The abbreviated facility report must include the following information:

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

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

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in § 98.33(a) and expressed in metric tons of CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, and CO<sub>2</sub>e.

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

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

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

(f) *Verification.* To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(8) and

(d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) *Recordkeeping.* An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least 3 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

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

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

(i) The GHG emissions calculations and methods used.

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

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

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

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the duration of the event, actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.

(5) A written GHG Monitoring Plan.

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

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

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

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

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

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

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

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

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

(h) *Annual GHG report revisions.* The 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.

(i) *Calibration accuracy requirements.* The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the calibration accuracy requirements of this paragraph (i).

(1) Except as provided paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted on the date that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.

(2) For flow meters, perform all calibrations at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A-2 of this section. The terms "R" and "A" in Equation A-2 must be expressed in consistent units of measure (e.g., gallons/minute, ft<sup>3</sup>/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. 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 5.0 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

(4) Fuel billing meters are exempted from the calibration requirements 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.

(5) For a flow meter or other measurement device that has been previously calibrated in accordance with this part, an initial calibration is not required by the date specified in paragraph (i)(1) of this section if, as of the date required for the initial calibration, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations, as required by this part, has not elapsed).

(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 removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations. Such postponements shall be documented in the monitoring plan that is required under § 98.3(g)(5).

#### § 98.4 Authorization and responsibilities of the designated representative.

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

CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

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

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

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

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

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of

those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

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

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

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

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

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

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

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

the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

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

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

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

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

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

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

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

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

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

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

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

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

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

*(l) Objections Concerning a Designated Representative*

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated

representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

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

(m) *Delegation by designated representative and alternate designated representative.*

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

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

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

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

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

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

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

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

deemed to be an electronic submission certified, signed, and submitted by me."

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

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

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

(4) Any electronic submission covered by the certification in paragraph (m)(2)(iv)(A) of this section and made in accordance with a notice of delegation effective under paragraph (m)(3) of this section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

**§ 98.5 How is the report submitted?**

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

**§ 98.6 Definitions.**

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

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

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

*Administrator* means the Administrator of the United States

Environmental Protection Agency or the Administrator's authorized representative.

*AGA* means the American Gas Association

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

*Anaerobic digester* means the system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to CO<sub>2</sub> and CH<sub>4</sub>, which is captured and may be flared or used as fuel. Anaerobic digestion systems, include but are not limited to covered lagoon, complete mix, plug flow, and fixed film digesters.

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

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

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

*ANSI* means the American National Standards Institute.

*API* means the American Petroleum Institute.

*Argon-oxygen decarburization (AOD) vessel* means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining to reduce the carbon content of the steel.

*ASABE* means the American Society of Agricultural and Biological Engineers.

*ASME* means the American Society of Mechanical Engineers.

*ASTM* means the American Society of Testing and Materials.

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

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

*B<sub>0</sub>* means the maximum CH<sub>4</sub> producing capacity of a waste stream, kg CH<sub>4</sub>/kg COD.

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

*bbl* means barrel.

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

*Biogenic CO<sub>2</sub>* means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable part 98 subpart.

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

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

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

*Blendstocks—Others* are products used for blending or compounding into

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

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

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

*Bulk*, with respect to industrial GHG suppliers and CO<sub>2</sub> suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

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

*Butane*, or n-Butane, is a paraffinic straight-chain hydrocarbon with molecular formula C<sub>4</sub>H<sub>10</sub>.

*Butylene*, or n-Butylene, is an olefinic straight-chain hydrocarbon with molecular formula C<sub>4</sub>H<sub>8</sub>.

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

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

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

*Carbon dioxide equivalent or CO<sub>2</sub>e* means the number of metric tons of CO<sub>2</sub> emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A-1 of this subpart.

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

*Carbon dioxide production well facility* means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO<sub>2</sub> production well facility if they otherwise meet the definition.

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

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

*Carbonate* means compounds containing the radical CO<sub>3</sub><sup>-2</sup>. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO<sub>2</sub>). Common carbonates consumed in the mineral industry include calcium carbonate (CaCO<sub>3</sub>) or calcite; magnesium carbonate (MgCO<sub>3</sub>) or magnesite; and calcium-magnesium carbonate (CaMg(CO<sub>3</sub>)<sub>2</sub>) or dolomite.

*Carbonate-based mineral* means any of the following minerals used in the manufacture of glass: Calcium carbonate (CaCO<sub>3</sub>), calcium magnesium carbonate (CaMg(CO<sub>3</sub>)<sub>2</sub>), and sodium carbonate (Na<sub>2</sub>CO<sub>3</sub>).

*Carbonate-based mineral mass fraction* means the following: For limestone, the mass fraction of CaCO<sub>3</sub> in the limestone; for dolomite, the mass fraction of CaMg(CO<sub>3</sub>)<sub>2</sub> in the dolomite; and for soda ash, the mass fraction of Na<sub>2</sub>CO<sub>3</sub> in the soda ash.

*Carbonate-based raw material* means any of the following materials used in the manufacture of glass: Limestone, dolomite, and soda ash.

*Catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as

fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

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

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

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

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

*CH<sub>4</sub>* means methane.

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

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

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

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

local distribution company system and typically are used to measure local distribution company system sendout to customers.

CO<sub>2</sub> means carbon dioxide.

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

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

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

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

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

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

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

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

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

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

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

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

*Crude oil* means a mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities.

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

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

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

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

drums and ancillary equipment associated with a single fractionator.

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

*Destruction* means:

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

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

*Destruction Efficiency* means the efficiency with which a destruction device reduces the GWP-weighted mass of greenhouse gases fed into the device, considering the GWP-weighted masses of both the greenhouse gases fed into the device and those exhausted from the device. Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized. The Destruction Efficiency is expressed in Equation A-2 of this section:

$$DE = 1 - \frac{tCO_2e_{OUT}}{tCO_2e_{IN}} \quad (\text{Eq. A-2})$$

Where:

DE = Destruction Efficiency

$tCO_2e_{IN}$  = The GWP-weighted mass of GHGs fed into the destruction device

$tCO_2e_{OUT}$  = The GWP-weighted mass of GHGs exhausted from the destruction device, including GHGs formed during the destruction process

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

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

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

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

*Distillate Fuel Oil* means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers

and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

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

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

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

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

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

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

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

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

*Emergency generator* means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a

facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

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

*ETBE* (ethyl tertiary butyl ether,  $(\text{CH}_3)_3\text{COC}_2\text{H}$ ) is an ether as described in "Oxygenates."

*Ethane* is a paraffinic hydrocarbon with molecular formula  $\text{C}_2\text{H}_6$ .

*Ethanol* is an anhydrous alcohol with molecular formula  $\text{C}_2\text{H}_5\text{OH}$ .

*Ethylene* is an olefinic hydrocarbon with molecular formula  $\text{C}_2\text{H}_4$ .

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

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

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

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

*Facility* means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common

ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

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

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

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

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

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

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

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

used as fuel in other combustion sources at the refinery.

*Fluorinated greenhouse gas* means sulfur hexafluoride ( $\text{SF}_6$ ), nitrogen trifluoride ( $\text{NF}_3$ ), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, "fluorinated GHG" includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

*Fossil fuel* means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

*Fossil fuel-fired* means powered by combustion of fossil fuel, alone or in combination with any other fuel, regardless of the percentage of fossil fuel consumed.

*Fractionators* means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus ( $\text{C}_5+$ ). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

*Fuel* means solid, liquid or gaseous combustible material.

*Fuel gas* means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.

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

*Gas collection system or landfill gas collection system* means a system of pipes used to collect landfill gas from different locations in the landfill to a

single location for treatment (thermal destruction) or use. Landfill gas collection systems may also include knock-out or separator drums and/or a compressor.

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

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

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

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

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

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

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

*Global warming potential or GWP* means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram- of a reference gas, i.e., CO<sub>2</sub>.

*GPA* means the Gas Processors Association.

*Greenhouse gas or GHG* means carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), sulfur hexafluoride (SF<sub>6</sub>), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

*GTBA* (gasoline-grade tertiary butyl alcohol, (CH<sub>3</sub>)<sub>3</sub>COH), or t-butanol, is an alcohol as described in "Oxygenates."

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

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

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

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

*Import* means, to land on, bring into, or introduce into, any place subject to

the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:

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

(2) Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous oxide had been admitted into Mexico in bond and were of U.S. origin.

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

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

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

(1) The consignee.

(2) The importer of record.

(3) The actual owner.

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

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

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

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

*Isobutane* is a paraffinic branch chain hydrocarbon with molecular formula C<sub>4</sub>H<sub>10</sub>.

*Isobutylene* is an olefinic branch chain hydrocarbon with molecular formula C<sub>4</sub>H<sub>8</sub>.

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

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

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

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

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

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

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

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

*Makeup chemicals* means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the chemical recovery areas of chemical

pulp mills to replace chemicals lost in the process.

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

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

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

*Mcf* means thousand cubic feet.

*Methane conversion factor* means the extent to which the CH<sub>4</sub> producing capacity (B<sub>o</sub>) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

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

*Methanol* (CH<sub>3</sub>OH) is an alcohol as described in "Oxygenates."

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

gasoline after oxygenate has been added to the RBOB or CBOB.

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

*MMBtu* means million British thermal units.

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

*Mscf* means million standard cubic feet.

*MTBE* (methyl tertiary butyl ether, (CH<sub>3</sub>)<sub>3</sub>COCH<sub>3</sub>) is an ether as described in "Oxygenates."

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

*Municipal solid waste or MSW* means solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse.

*N<sub>2</sub>O* means nitrous oxide.

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

*Natural gas* means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's

surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

*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 at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

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

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

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

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

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

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

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

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

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

*Operational change* means, for purposes of § 98.3(b), a change in the type of feedstock or fuel used, a change

in operating hours, or a change in process production rate.

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

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

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

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

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

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

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

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

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

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

*Petroleum coke* means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has

low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

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

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

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

- (1) The equipment is attached to a foundation.
- (2) The equipment or a replacement resides at the same location for more than 12 consecutive months.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

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

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

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

manure composting when designed and operated properly.

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

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

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

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

*Process emissions* means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO<sub>2</sub> emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

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

*Process vent* means means a gas stream that is discharged through a conveyance to the atmosphere either directly or after passing through a

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

*Propane* is a paraffinic hydrocarbon with molecular formula  $C_3H_8$ .

*Propylene* is an olefinic hydrocarbon with molecular formula  $C_3H_6$ .

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*Rotary lime kiln* means a unit with an inclined rotating drum that is used to

produce a lime product from limestone by calcination.

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

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

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

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

*SF<sub>6</sub>* means sulfur hexafluoride.

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

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

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

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

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

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

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

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

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

*Spent pulping liquor* means the residual liquid collected from on-site

pulping operations at chemical pulp facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

*Standard conditions or standard temperature and pressure (STP)* means 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

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

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

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

*Sulfur recovery plant* means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H<sub>2</sub>S) and/or sulfur dioxide (SO<sub>2</sub>) from a common source of sour gas at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single sulfur recovery plant only when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are separate sulfur recovery plants.

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

*Supplier* means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

*Taconite iron ore processing* means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are used as

the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.

*TAME* means tertiary amyl methyl ether, (CH<sub>3</sub>)<sub>2</sub>(C<sub>2</sub>H<sub>5</sub>)COCH<sub>3</sub>.

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

*Transform* means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes. Transformation does not include burning of nitrous oxide.

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

*Trona* means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (e.g., Na<sub>2</sub>CO<sub>3</sub>·NaHCO<sub>3</sub>·2H<sub>2</sub>O).

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

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

*United States* means the 50 states, the District of Columbia, and U.S. possessions and territories.

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

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

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

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

*Waelz kiln* means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon

reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

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

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

*You* means an owner or operator subject to Part 98.

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

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

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

(a) The following material is available for purchase from the Association of Fertilizer and Phosphate Chemists (AFPC), P.O. Box 1645, Bartow, Florida 33831, <http://afpc.net>.

(1) Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009—Version 1.9, incorporation by reference

(IBR) approved for § 98.264(a) and § 98.264(b).

(2) [Reserved]

(b) The following material is available for purchase from the American Gas Association (AGA), 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>.

(1) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations & Uncertainty Guidelines (1990), incorporation by reference (IBR) approved for § 98.34(b) and § 98.244(b).

(2) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 2: Specification and Installation Requirements (2000), IBR approved for § 98.34(b) and § 98.244(b).

(3) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 98.244(b) and § 98.254(c).

(4) AGA Transmission Measurement Committee Report No. 7 Measurement of Natural Gas by Turbine Meter (2006)/February, IBR approved for § 98.34(b) and § 98.244(b).

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

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

(2) [Reserved]

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

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(3) ASME MFC-5M-1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 98.34(b) and § 98.244(b).

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

(6) ASME MFC-9M-1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 98.34(b) and § 98.244(b).

(7) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 98.244(b), § 98.254(c), and § 98.344(c).

(8) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(9) ASME MFC-16-2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 98.244(b).

(10) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 98.244(b), § 98.254(c), § 98.344(c), and § 98.364(e).

(11) ASME MFC-22-2007 Measurement of Liquid by Turbine Flowmeters, IBR approved for § 98.244(b).

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

(1) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, incorporation by reference (IBR) approved for § 98.114(b), § 98.174(b), § 98.184(b), § 98.194(c), and § 98.334(b).

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

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

(4) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for § 98.34(a) and § 98.254(e).

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

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

(7) ASTM D1298-99 (Reapproved 2005) Standard Test Method for Density,

Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, IBR approved for § 98.33(a).

(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 § 98.34(a) and § 98.254(e).

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

(10) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 98.34(b), § 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 § 98.34(b), § 98.74(c), § 98.164(b), § 98.254(d), § 98.344(b), and § 98.364(c).

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

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

(14) ASTM D2502–04 Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements, IBR approved for § 98.34(b) and § 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 § 98.34(b) and § 98.74(c).

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

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

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

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

approved for § 98.34(b), § 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 § 98.34(a) and § 98.254(e).

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

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

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

(24) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 98.34(a) and § 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 § 98.34(a) and § 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 § 98.34(b), § 98.74(c), § 98.164(b), § 98.244(b), § 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 § 98.34(b), § 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) ASTM D5865–07a Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for § 98.34(a).

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

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

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

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

(33) ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, IBR approved for § 98.33(e), § 98.34(d), § 98.34(e), and § 98.36(e).

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

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

(36) ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources, IBR approved for § 98.33(e), § 98.34(d), § 98.34(e), and § 98.36(e).

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

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

(39) ASTM E1747–95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications, IBR approved for § 98.424(b).

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

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

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

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

(1) GPA 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer, IBR approved for § 98.34(a).

(2) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for

§ 98.34(a), § 98.164(b), § 98.254(d), and § 98.344(b).

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

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

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

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01)—First Edition, IBR approved for § 98.244(b).

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

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

(h) The following material is available for purchase from the National Lime

Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243-5463, <http://www.lime.org>.

(1) CO<sub>2</sub> Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association, incorporation by reference (IBR) approved for § 98.194(c) and § 98.194(e).

(2) [Reserved]

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

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

(2) [Reserved]

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

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

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation

by reference (IBR) approved for § 98.274(b).

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

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

**§ 98.9 Addresses.**

All requests, notifications, and communications to the Administrator pursuant to this part, other than submittal of the annual GHG report, shall be submitted to the following address:

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

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

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS [100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124-38-9	CO <sub>2</sub>	1
Methane	74-82-8	CH <sub>4</sub>	21
Nitrous oxide	10024-97-2	N <sub>2</sub> O	310
HFC-23	75-46-7	CHF <sub>3</sub>	11,700
HFC-32	75-10-5	CH <sub>2</sub> F <sub>2</sub>	650
HFC-41	593-53-3	CH <sub>3</sub> F	150
HFC-125	354-33-6	C <sub>2</sub> H <sub>2</sub> F <sub>5</sub>	2,800
HFC-134	359-35-3	C <sub>2</sub> H <sub>2</sub> F <sub>4</sub>	1,000
HFC-134a	811-97-2	CH <sub>2</sub> FCF <sub>3</sub>	1,300
HFC-143	430-66-0	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub>	300
HFC-143a	420-46-2	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub>	3,800
HFC-152	624-72-6	CH <sub>2</sub> FCH <sub>2</sub> F	53
HFC-152a	75-37-6	CH <sub>3</sub> CHF <sub>2</sub>	140
HFC-161	353-36-6	CH <sub>3</sub> CH <sub>2</sub> F	12
HFC-227ea	431-89-0	C <sub>3</sub> HF <sub>7</sub>	2,900
HFC-236cb	677-56-5	CH <sub>2</sub> FCF <sub>2</sub> CF <sub>3</sub>	1,340
HFC-236ea	431-63-0	CHF <sub>2</sub> CHFCF <sub>3</sub>	1,370
HFC-236fa	690-39-1	C <sub>3</sub> H <sub>2</sub> F <sub>6</sub>	6,300
HFC-245ca	679-86-7	C <sub>3</sub> H <sub>3</sub> F <sub>5</sub>	560
HFC-245fa	460-73-1	CHF <sub>2</sub> CH <sub>2</sub> CF <sub>3</sub>	1,030
HFC-365mfc	406-58-6	CH <sub>3</sub> CF <sub>2</sub> CH <sub>2</sub> CF <sub>3</sub>	794
HFC-43-10mee	138495-42-8	CF <sub>3</sub> CFHCFHCF <sub>2</sub> CF <sub>3</sub>	1,300
Sulfur hexafluoride	2551-62-4	SF <sub>6</sub>	23,900
Trifluoromethyl sulphur pentafluoride	373-80-8	SF <sub>5</sub> CF <sub>3</sub>	17,700
Nitrogen trifluoride	7783-54-2	NF <sub>3</sub>	17,200
PFC-14 (Perfluoromethane)	75-73-0	CF <sub>4</sub>	6,500
PFC-116 (Perfluoroethane)	76-16-4	C <sub>2</sub> F <sub>6</sub>	9,200
PFC-218 (Perfluoropropane)	76-19-7	C <sub>3</sub> F <sub>8</sub>	7,000

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS—Continued  
[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Perfluorocyclopropane	931-91-9	C-C <sub>3</sub> F <sub>6</sub>	17,340
PFC-3-1-10 (Perfluorobutane)	355-25-9	C <sub>4</sub> F <sub>10</sub>	7,000
Perfluorocyclobutane	115-25-3	C-C <sub>4</sub> F <sub>8</sub>	8,700
PFC-4-1-12 (Perfluoropentane)	678-26-2	C <sub>5</sub> F <sub>12</sub>	7,500
PFC-5-1-14 (Perfluorohexane)	355-42-0	C <sub>6</sub> F <sub>14</sub>	7,400
PFC-9-1-18	306-94-5	C <sub>10</sub> F <sub>18</sub>	7,500
HCFE-235da2 (Isoflurane)	26675-46-7	CHF <sub>2</sub> OCHClCF <sub>3</sub>	350
HFE-43-10pccc (H-Galden 1040x)	E1730133	CHF <sub>2</sub> OCF <sub>2</sub> OCF <sub>2</sub> F <sub>4</sub> OCHF <sub>2</sub>	1,870
HFE-125	3822-68-2	CHF <sub>2</sub> OCF <sub>3</sub>	14,900
HFE-134	1691-17-4	CHF <sub>2</sub> OCHF <sub>2</sub>	6,320
HFE-143a	421-14-7	CH <sub>3</sub> OCF <sub>3</sub>	756
HFE-227ea	2356-62-9	CF <sub>3</sub> CHFOCF <sub>3</sub>	1,540
HFE-236ca12 (HG-10)	78522-47-1	CHF <sub>2</sub> OCF <sub>2</sub> OCHF <sub>2</sub>	2,800
HFE-236ea2 (Desflurane)	57041-67-5	CHF <sub>2</sub> OCHF <sub>2</sub> CF <sub>3</sub>	989
HFE-236fa	20193-67-3	CF <sub>3</sub> CH <sub>2</sub> OCF <sub>3</sub>	487
HFE-245cb2	22410-44-2	CH <sub>3</sub> OCF <sub>2</sub> CF <sub>3</sub>	708
HFE-245fa1	84011-15-4	CHF <sub>2</sub> CH <sub>2</sub> OCF <sub>3</sub>	286
HFE-245fa2	1885-48-9	CHF <sub>2</sub> OCH <sub>2</sub> CF <sub>3</sub>	659
HFE-254cb2	425-88-7	CH <sub>3</sub> OCF <sub>2</sub> CHF <sub>2</sub>	359
HFE-263fb2	460-43-5	CF <sub>3</sub> CH <sub>2</sub> OCH <sub>3</sub>	11
HFE-329mcc2	67490-36-2	CF <sub>3</sub> CF <sub>2</sub> OCF <sub>2</sub> CHF <sub>2</sub>	919
HFE-338mcf2	156053-88-2	CF <sub>3</sub> CF <sub>2</sub> OCH <sub>2</sub> CF <sub>3</sub>	552
HFE-338pcc13 (HG-01)	188690-78-0	CHF <sub>2</sub> OCF <sub>2</sub> CF <sub>2</sub> OCHF <sub>2</sub>	1,500
HFE-347mcc3	28523-86-6	CH <sub>3</sub> OCF <sub>2</sub> CF <sub>2</sub> CF <sub>3</sub>	575
HFE-347mcf2	E1730135	CF <sub>3</sub> CF <sub>2</sub> OCH <sub>2</sub> CHF <sub>2</sub>	374
HFE-347pcf2	406-78-0	CHF <sub>2</sub> CF <sub>2</sub> OCH <sub>2</sub> CF <sub>3</sub>	580
HFE-356mec3	382-34-3	CH <sub>3</sub> OCF <sub>2</sub> CHFCF <sub>3</sub>	101
HFE-356pcc3	160620-20-2	CH <sub>3</sub> OCF <sub>2</sub> CF <sub>2</sub> CHF <sub>2</sub>	110
HFE-356pcf2	E1730137	CHF <sub>2</sub> CH <sub>2</sub> OCF <sub>2</sub> CHF <sub>2</sub>	265
HFE-356pcf3	35042-99-0	CHF <sub>2</sub> OCH <sub>2</sub> CF <sub>2</sub> CHF <sub>2</sub>	502
HFE-365mcf3	378-16-5	CF <sub>3</sub> CF <sub>2</sub> CH <sub>2</sub> OCH <sub>3</sub>	11
HFE-374pc2	512-51-6	CH <sub>3</sub> CH <sub>2</sub> OCF <sub>2</sub> CHF <sub>2</sub>	557
HFE-449sl (HFE-7100)	163702-07-6	C <sub>4</sub> F <sub>9</sub> OCH <sub>3</sub>	297
Chemical blend	163702-08-7	(CF <sub>3</sub> ) <sub>2</sub> CF <sub>2</sub> OCF <sub>2</sub> OCH <sub>3</sub>	
HFE-569sf2 (HFE-7200)	163702-05-4	C <sub>4</sub> F <sub>9</sub> OC <sub>2</sub> H <sub>5</sub>	59
Chemical blend	163702-06-5	(CF <sub>3</sub> ) <sub>2</sub> CF <sub>2</sub> OC <sub>2</sub> H <sub>5</sub>	
Sevoflurane	28523-86-6	CH <sub>2</sub> FOCH(CF <sub>3</sub> ) <sub>2</sub>	345
HFE-356mm1	13171-18-1	(CF <sub>3</sub> ) <sub>2</sub> CHOCH <sub>3</sub>	27
HFE-338mmz1	26103-08-2	CHF <sub>2</sub> OCH(CF <sub>3</sub> ) <sub>2</sub>	380
(Octafluorotetramethyl-ene)hydroxymethyl group	NA	X-(CF <sub>2</sub> ) <sub>4</sub> CH(OH)-X	73
HFE-347mmy1	22052-84-2	CH <sub>3</sub> OCF(CF <sub>3</sub> ) <sub>2</sub>	343
Bis(trifluoromethyl)-methanol	920-66-1	(CF <sub>3</sub> ) <sub>2</sub> CHOH	195
2,2,3,3,3-pentafluoropropanol	422-05-9	CF <sub>3</sub> CF <sub>2</sub> CH <sub>2</sub> OH	42
PFPME	NA	CF <sub>3</sub> OCF(CF <sub>3</sub> )CF <sub>2</sub> OCF <sub>2</sub> OCF <sub>3</sub>	10,300

NA = not available.

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

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462
Pounds (lbs)	Kilograms (kg)	0.45359
Pounds (lbs)	Metric tons	4.53592 × 10 <sup>-4</sup>
Short tons	Pounds (lbs)	2,000
Short tons	Metric tons	0.90718
Metric tons	Short tons	1.10231
Metric tons	Kilograms (kg)	1,000
Cubic meters (m <sup>3</sup> )	Cubic feet (ft <sup>3</sup> )	35.31467
Cubic feet (ft <sup>3</sup> )	Cubic meters (m <sup>3</sup> )	0.028317
Gallons (liquid, US)	Liters (l)	3.78541
Liters (l)	Gallons (liquid, US)	0.26417
Barrels of Liquid Fuel (bbl)	Cubic meters (m <sup>3</sup> )	0.15891
Cubic meters (m <sup>3</sup> )	Barrels of Liquid Fuel (bbl)	6.289
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810
Gallons (liquid, US)	Cubic meters (m <sup>3</sup> )	0.0037854
Liters (l)	Cubic meters (m <sup>3</sup> )	0.001

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

To convert from	To	Multiply by
Feet (ft)	Meters (m)	0.3048
Meters (m)	Feet (ft)	3.28084
Miles (mi)	Kilometers (km)	1.60934
Kilometers (km)	Miles (mi)	0.62137
Square feet (ft <sup>2</sup> )	Acres	2.29568 × 10 <sup>-5</sup>
Square meters (m <sup>2</sup> )	Acres	2.47105 × 10 <sup>-4</sup>
Square miles (mi <sup>2</sup> )	Square kilometers (km <sup>2</sup> )	2.58999
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	°C = (5/9) × (°F - 32)
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	°F = (9/5) × °C + 32
Degrees Celsius (°C)	Kelvin (K)	K = °C + 273.15
Kelvin (K)	Degrees Rankine (°R)	1.8
Joules	Btu	9.47817 × 10 <sup>-4</sup>
Btu	MMBtu	1 × 10 <sup>-6</sup>
Pascals (Pa)	Inches of Mercury (in Hg)	2.95334 × 10 <sup>-4</sup>
Inches of Mercury (in Hg)	Pounds per square inch (psi)	0.49110
Pounds per square inch (psi)	Inches of Mercury (in Hg)	2.03625

**Subpart B—[Reserved]**

**Subpart C—General Stationary Fuel Combustion Sources**

**§ 98.30 Definition of the source category.**

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

(b) This source category does not include:

- (1) Portable equipment, as defined in § 98.6.
- (2) Emergency generators and emergency equipment, as defined in § 98.6.
- (3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.

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

(c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:

- (1) Continuous emission monitors (CEMS) are used to quantify CO<sub>2</sub> mass emissions.
- (2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C-1 of this subpart.

**§ 98.31 Reporting threshold.**

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

**§ 98.32 GHGs to report.**

You must report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O mass emissions from each stationary fuel combustion unit.

**§ 98.33 Calculating GHG emissions.**

You must calculate CO<sub>2</sub> emissions according to paragraph (a) of this section, and calculate CH<sub>4</sub> and N<sub>2</sub>O emissions according to paragraph (c) of this section.

(a) *CO<sub>2</sub> emissions from fuel combustion.* Calculate CO<sub>2</sub> emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO<sub>2</sub> emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO<sub>2</sub> mass emissions for each type of fuel by using Equation C-1 of this section.

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

Where:

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions for the specific fuel type (metric tons).
- Fuel = Mass or volume of fuel combusted per year, from company records as defined in § 98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
- HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu

- per mass or mmBtu per volume, as applicable).
- EF = Fuel-specific default CO<sub>2</sub> emission factor, from Table C-1 of this subpart (kg CO<sub>2</sub>/mmBtu).
- 1 × 10<sup>-3</sup> = Conversion factor from kilograms to metric tons.

(2) *Tier 2 Calculation Methodology.* Calculate the annual CO<sub>2</sub> mass emissions for each type of fuel by using

either Equation C2a or C2c of this section, as appropriate.

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

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

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions for a specific fuel type (metric tons).

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

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated

according to the requirements of paragraph (a)(2)(ii) of this section.  
EF = Fuel-specific default CO<sub>2</sub> emission factor, from Table C-1 of this subpart (kg CO<sub>2</sub>/mmBtu).  
1 × 10<sup>-3</sup> = Conversion factor from kilograms to metric tons.

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in § 98.34. The method for computing the annual average HHV is a function of

how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

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

Where:

(HHV)<sub>annual</sub> = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

(HHV)<sub>i</sub> = High heat value of the fuel, for month "i" (mmBtu per mass or volume).

(Fuel)<sub>i</sub> = Mass or volume of the fuel combusted during month "i" (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 fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then 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).

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

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

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from MSW or solid fuel combustion (metric tons).

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

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).  
EF = Fuel-specific default CO<sub>2</sub> emission factor, from Table C-1 of this subpart (kg CO<sub>2</sub>/mmBtu).  
1 × 10<sup>-3</sup> = Conversion factor from kilograms to metric tons.

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO<sub>2</sub> mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

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

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

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from the combustion of the specific solid fuel (metric tons).

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

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

44/12 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

0.91 = Conversion factor from short tons to metric tons.

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

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

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated

according to § 98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as

specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

0.001 = Conversion factor from kg to metric tons.

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

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

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from combustion of the specific gaseous fuel (metric tons).

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

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

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

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in § 98.6).

44/12 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid 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, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method" (incorporated by reference, see § 98.7).

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

(4) *Tier 4 Calculation Methodology.* Calculate the annual CO<sub>2</sub> mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO<sub>2</sub> concentration monitor and a stack gas volumetric flow rate monitor, except as

otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO<sub>2</sub> concentration and stack gas flow rate are converted to CO<sub>2</sub> mass emission rates in metric tons per hour.

(ii) When the CO<sub>2</sub> concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO<sub>2</sub> emission rates:

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

Where:

CO<sub>2</sub> = CO<sub>2</sub> mass emission rate (metric tons/hr).

C<sub>CO<sub>2</sub></sub> = Hourly average CO<sub>2</sub> concentration (% CO<sub>2</sub>).

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

5.18 × 10<sup>-7</sup> = Conversion factor (metric tons/scf/% CO<sub>2</sub>).

(iii) If the CO<sub>2</sub> 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, for certain types of fuel, use a default moisture percentage from § 75.11(b)(1) of this chapter. 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:

CO<sub>2</sub>\* = Hourly CO<sub>2</sub> mass emission rate, corrected for moisture (metric tons/hr).

CO<sub>2</sub> = Hourly CO<sub>2</sub> mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).

%H<sub>2</sub>O = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O<sub>2</sub>) concentration monitor may be used in lieu of a CO<sub>2</sub> concentration monitor to determine the hourly CO<sub>2</sub> concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to 40 CFR part 75, if the effluent gas stream monitored by the CEMS consists solely

of combustion products (i.e., no process CO<sub>2</sub> emissions 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 40 CFR part 75 are combusted in the unit. If the O<sub>2</sub> 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 40 CFR part 75, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with § 75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from § 75.11(b)(1) of this chapter.

(v) Each hourly CO<sub>2</sub> mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO<sub>2</sub> mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO<sub>2</sub> mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO<sub>2</sub> mass emissions separately, as described in paragraph (e) of this section.

(5) *Alternative methods for units with continuous monitoring systems.* Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75 may use the alternative methods in this paragraph 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 the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part

75, but is not required by the applicable 40 CFR part 75 program to report CO<sub>2</sub> mass emissions data, calculate the annual CO<sub>2</sub> mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G-4 in appendix G to 40 CFR part 75 to determine the hourly CO<sub>2</sub> mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO<sub>2</sub> mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO<sub>2</sub> mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO<sub>2</sub> mass emissions data, calculate the annual CO<sub>2</sub> mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO<sub>2</sub> mass emissions, in units of short tons, using Equation LM-11 in 40 CFR 75.19(c)(4)(iii).

(B) Sum the hourly CO<sub>2</sub> mass emissions values over the entire reporting year to obtain the cumulative annual CO<sub>2</sub> mass emissions, in units of short tons.

(C) Divide the cumulative annual CO<sub>2</sub> mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO<sub>2</sub> (or O<sub>2</sub>) CEMS to report heat input data year-round according to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO<sub>2</sub> mass emissions data, calculate the annual CO<sub>2</sub> mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO<sub>2</sub> mass emission rates from the CEMS data. If an O<sub>2</sub> monitor is used, convert the hourly average O<sub>2</sub> readings to CO<sub>2</sub> using Equation F-14a or F-14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO<sub>2</sub> mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO<sub>2</sub> mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO<sub>2</sub> mass emissions separately, as described in paragraph (e) of this section.

(b) *Use of the four tiers.* Use of the four tiers of CO<sub>2</sub> emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in § 98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C-1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii) and (b)(2)(ii) of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C-1 of this subpart if the fuel

is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides 10% or more of the annual heat input to the unit or, if § 98.36(c)(3) applies, to a group of units served by common supply pipe.

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, 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 40 CFR part 75, appendix F to 40 CFR part 60, 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 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO<sub>2</sub> concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO<sub>2</sub> and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO<sub>2</sub> mass emissions beginning on that date, if all of the monitors needed to measure CO<sub>2</sub> mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO<sub>2</sub> mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO<sub>2</sub> 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.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO<sub>2</sub> emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) *Calculation of CH<sub>4</sub> and N<sub>2</sub>O emissions from stationary combustion sources.* You must calculate annual CH<sub>4</sub> and N<sub>2</sub>O mass emissions only for units that are required to report CO<sub>2</sub> emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO<sub>2</sub>. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * HHV * EF \quad (\text{Eq. C-8})$$

Where:

CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C-1 of this subpart (mmBtu per mass or volume).  
EF = Fuel-specific default emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Table C-2 of this subpart (kg CH<sub>4</sub> or N<sub>2</sub>O per mmBtu).  
 $1 \times 10^{-3}$  = Conversion factor from kilograms to metric tons.

(2) Use Equation C-9a of this section to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO<sub>2</sub> emissions. Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * HHV * EF * Fuel \quad (\text{Eq. C-9a})$$

Where:

CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the

reporting year (mmBtu per mass or volume).  
EF = Fuel-specific default emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Table C-2 of this subpart (kg CH<sub>4</sub> or N<sub>2</sub>O per mmBtu).  
 $1 \times 10^{-3}$  = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO<sub>2</sub> emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Steam * B * EF \quad (\text{Eq. C-9b})$$

Where:

CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a solid fuel (metric tons).

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

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).  
EF = Fuel-specific emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Table C-2 of this subpart (kg CH<sub>4</sub> or N<sub>2</sub>O per mmBtu).  
 $1 \times 10^{-3}$  = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \quad (\text{Eq. C-10})$$

Where:

CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a particular type of fuel (metric tons).

(HI)<sub>A</sub> = Cumulative annual heat input from the fuel, derived from the electronic data reports required under § 75.64 of this chapter or, for Tier 4 units, from the best available information as described in

paragraph (c)(4)(ii) of this section (mmBtu).  
EF = Fuel-specific emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Table C-2 of this section (kg CH<sub>4</sub> or N<sub>2</sub>O per mmBtu).  
0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH<sub>4</sub> or N<sub>2</sub>O emissions.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, use Equation C-10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available information (e.g., fuel feed rate measurements, fuel heating values,

engineering analysis) to estimate the annual heat input from each type of fuel.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH<sub>4</sub> and N<sub>2</sub>O emissions, in metric tons.

(d) Calculation of CO<sub>2</sub> from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation C-11 of this section to calculate the CO<sub>2</sub> emissions from the sorbent, if those CO<sub>2</sub> emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left( \frac{MW_{CO_2}}{MW_S} \right) \quad (\text{Eq. C-11})$$

Where:

CO<sub>2</sub> = CO<sub>2</sub> emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = 1.00, the calcium-to-sulfur stoichiometric ratio.

MW<sub>CO<sub>2</sub></sub> = Molecular weight of carbon dioxide (44).

MW<sub>S</sub> = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons.

(2) The annual CO<sub>2</sub> mass emissions for the unit shall be the sum of the CO<sub>2</sub> emissions from the combustion process and the CO<sub>2</sub> emissions from the sorbent.

(e) *CO<sub>2</sub> emissions from combustion of biomass.* Use the procedures of this paragraph (e) to estimate biogenic CO<sub>2</sub> emissions from units that combust a combination of biomass and fossil fuels.

Reporting of CO<sub>2</sub> emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO<sub>2</sub>, use Equation C-1 of this subpart to calculate the annual CO<sub>2</sub> mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e)(5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the

procedure used in the GHG Monitoring Plan required by § 98.3(g)(5).

(2) If a CO<sub>2</sub> CEMS (or a surrogate O<sub>2</sub> monitor) and a stack gas flow rate monitor are used to determine the annual CO<sub>2</sub> mass emissions either according to 40 CFR part 75, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted in the unit during the reporting year, you may use the following procedure to determine the annual biogenic CO<sub>2</sub> mass emissions. If MSW is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO<sub>2</sub> emitted.

$$V_{CO_2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \quad (\text{Eq. C-12})$$

Where:

V<sub>CO<sub>2</sub>h</sub> = Hourly volume of CO<sub>2</sub> emitted (scf).

(%CO<sub>2</sub>)<sub>h</sub> = Hourly average CO<sub>2</sub> concentration, measured by the CO<sub>2</sub> concentration monitor, or, if applicable, calculated from the hourly average O<sub>2</sub> concentration (%CO<sub>2</sub>).

Q<sub>h</sub> = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t<sub>h</sub> = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V<sub>CO<sub>2</sub>h</sub> values for the reporting year, to obtain V<sub>total</sub>, the total annual volume of CO<sub>2</sub> emitted.

(iii) Calculate the annual volume of CO<sub>2</sub> emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are

combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{\text{Fuel} * F_c * HHV}{10^6} \quad (\text{Eq. C-13})$$

Where:

V<sub>ff</sub> = Annual volume of CO<sub>2</sub> emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in § 98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F<sub>c</sub> = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO<sub>2</sub>/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in § 98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10<sup>6</sup> = Conversion factor, Btu per mmBtu.

(iv) Subtract V<sub>ff</sub> from V<sub>total</sub> to obtain V<sub>bio</sub>, the annual volume of CO<sub>2</sub> from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO<sub>2</sub> process emissions from V<sub>total</sub> to determine V<sub>bio</sub>. The CO<sub>2</sub> process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO<sub>2</sub> emissions, expressed as a decimal fraction, using Equation C-14 of this section:

$$\% \text{ Biogenic} = \frac{V_{\text{bio}}}{V_{\text{total}}} \quad (\text{Eq. C-14})$$

(vi) Calculate the annual biogenic CO<sub>2</sub> mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO<sub>2</sub> mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under § 75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO<sub>2</sub> mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO<sub>2</sub> mass emissions, multiply the cumulative annual CO<sub>2</sub> mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO<sub>2</sub> emissions shall be calculated using the procedures in this paragraph (e)(3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO<sub>2</sub> mass emissions:

(A) Use Equation C-1 or C-2c of this subpart, as appropriate, to calculate the annual CO<sub>2</sub> mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO<sub>2</sub> emissions on a quarterly basis using the method specified in § 98.34(d).

(C) Determine the annual biogenic CO<sub>2</sub> mass emissions from MSW combustion by multiplying the annual CO<sub>2</sub> mass emissions by the annual average biogenic decimal fraction obtained from § 98.34(d).

(ii) If the unit uses Tier 4 to quantify CO<sub>2</sub> emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V<sub>total</sub>.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V<sub>ff</sub>.

(C) Subtract V<sub>ff</sub> from V<sub>total</sub>, to obtain V<sub>MSW</sub>, the annual volume of CO<sub>2</sub> emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO<sub>2</sub> emissions (V<sub>bio</sub>) from MSW combustion as follows. Multiply the annual volume of CO<sub>2</sub> emissions from MSW combustion (V<sub>MSW</sub>) by the annual average biogenic decimal fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(E) Calculate the biogenic percentage of the annual CO<sub>2</sub> emissions from the unit, using Equation C-14 of this section. For the purposes of this calculation, the term "V<sub>bio</sub>" in the

numerator of Equation C-14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO<sub>2</sub> mass emissions according to paragraph (e)(2)(vi)(A) of this section.

(4) As an alternative to the procedures in paragraph (e)(2) of this section, use ASTM Methods D7459-08 and D6866-08 to determine the biogenic portion of the annual CO<sub>2</sub> emissions, as described in § 98.34(e). If this option is selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO<sub>2</sub> is biogenic), and the values shall be averaged over the reporting year. The annual biogenic CO<sub>2</sub> mass emissions shall be calculated by multiplying the total annual CO<sub>2</sub> mass emissions by the annual average biogenic fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(5) If Equation C-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by § 98.3(g)(5).

$$(\text{Fuel})_p = \frac{[H * S] - (HI)_{nb}}{2000 (HHV)_{bio} (Eff)_{bio}} \quad (\text{Eq. C-15})$$

Where:

(Fuel)<sub>p</sub> = Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

(HI)<sub>nb</sub> = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

(HHV)<sub>bio</sub> = Default or measured high heat value of the biomass fuel (Btu/lb).

(Eff)<sub>bio</sub> = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

#### § 98.34 Monitoring and QA/QC requirements.

The CO<sub>2</sub> mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(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, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, 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.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to

obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraph (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specified in paragraph (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of § 98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. 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.

(i) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, *see* § 98.7).

(ii) ASTM D240–02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, *see* § 98.7).

(iii) ASTM D1826–94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, *see* § 98.7).

(iv) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, *see* § 98.7).

(v) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, *see* § 98.7).

(vi) GPA Standard 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid

Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, *see* § 98.7).

(vii) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(viii) ASTM D5865–07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, *see* § 98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to § 98.3(i) and the provisions of this paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(ii) In addition to the initial calibration required by § 98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, 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.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in § 98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to § 98.3(i), or use flow meters calibrated according to § 98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not

measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in this paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(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, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, 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 solid fuels other than coal, 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., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the

minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specified in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of § 98.35.

(v) The procedures of paragraph (a)(3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990) and Part 2: Specification and Installation Requirements (2000) (incorporated by reference, *see* § 98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, Measurement of Gas by Turbine Meters (2006) (incorporated by reference, *see* § 98.7).

(iii) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(iv) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(v) ASME MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, *see* § 98.7).

(vi) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(vii) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(viii) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, *see* § 98.7).

(5) Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. 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.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iii) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, *see* § 98.7).

(iv) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, *see* § 98.7).

(v) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, *see* § 98.7).

(vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(c) For the Tier 4 Calculation Methodology, the CO<sub>2</sub> and flow rate monitors must be certified prior to the applicable deadline specified in § 98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) § 75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO<sub>2</sub> concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O<sub>2</sub> concentration monitor is used to determine CO<sub>2</sub> concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO<sub>2</sub> basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO<sub>2</sub> monitor (or surrogate O<sub>2</sub> monitor) and the flow rate monitor, conduct cylinder gas audits of the CO<sub>2</sub> concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO<sub>2</sub> 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 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO<sub>2</sub> monitor (or surrogate O<sub>2</sub> monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of § 98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO<sub>2</sub> emissions from MSW combustion 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 while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Separate CO<sub>2</sub> emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO<sub>2</sub> from MSW combustion is biogenic). If there is a

common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO<sub>2</sub> mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866–08 and ASTM D7459–08 may be used to determine the biogenic portion of the CO<sub>2</sub> emissions. Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. 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 sample large enough to meet the specifications of ASTM D6866–08.

(f) Whenever company records are used in the calculation of CO<sub>2</sub> emissions, the records required under § 98.33(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

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

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when § 98.33(e) applies to a unit that uses CEMS to quantify CO<sub>2</sub> emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when § 98.33(d) applies.

(5) Quantity of steam generated by a unit when § 98.33(a)(2) applies.

(6) Biogenic fuel consumption under § 98.33(e)(5).

(g) As part of the GHG Monitoring Plan required under § 98.33(g)(5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

#### § 98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions report is due, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO<sub>2</sub> concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

#### § 98.36 Data reporting requirements.

(a) In addition to the facility-level information required under § 98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) *Units that use the four tiers.* You shall report the following information

for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in § 98.33(a) to calculate CO<sub>2</sub> emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The tier used to calculate the CO<sub>2</sub> emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO<sub>2</sub>e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO<sub>2</sub> emissions for all fuels combined. Reporting CO<sub>2</sub> emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO<sub>2</sub> emissions from combustion of all fossil fuels combined and the annual CO<sub>2</sub> emissions from combustion of all biomass fuels combined. Reporting CO<sub>2</sub> emissions by type of fuel is not required.

(iii) Annual CH<sub>4</sub> and N<sub>2</sub>O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO<sub>2</sub>e.

(8) Annual CO<sub>2</sub> emissions from sorbent (if calculated using Equation C–11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions), expressed in metric tons of CO<sub>2</sub>e.

(10) Customer meter number for units that combust natural gas.

(c) *Reporting alternatives for units using the four Tiers.* You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) *Aggregation of units.* If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for

any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

- (i) Group ID number, beginning with the prefix "GP".
- (ii) An identification number for each unit in the group.
- (iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).
- (iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).
- (v) Each type of fuel combusted in the group of units during the reporting year.
- (vi) Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO<sub>2</sub>e. If any of the units burn both fossil fuels and biomass, report also the annual CO<sub>2</sub> emissions from combustion of all fossil fuels combined and annual CO<sub>2</sub> emissions from combustion of all biomass fuels combined, expressed in metric tons.
- (vii) The tier used to calculate the CO<sub>2</sub> mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO<sub>2</sub> mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions), expressed in metric tons of CO<sub>2</sub>e.

(2) *Monitored common stack or duct configurations.* When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO<sub>2</sub> 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. The following information shall be reported instead of the information in paragraph (b) of this section:

- (i) Common stack or duct identification number, beginning with the prefix "CS".
- (ii) Identification numbers of the units sharing the common stack or duct.
- (iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).
- (iv) Each type of fuel combusted in the units during the year.
- (v) The methodology used to calculate the CO<sub>2</sub> mass emissions, i.e., Tier 4.

(vi) If the any of the units burn both fossil fuels and biomass, annual CO<sub>2</sub> mass emissions, annual CO<sub>2</sub> emissions from combustion of fossil fuels, and annual CO<sub>2</sub> emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.

(vii) The annual CH<sub>4</sub> and N<sub>2</sub>O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO<sub>2</sub>e.

(viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions), expressed in metric tons of CO<sub>2</sub>e.

(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 that is calibrated in accordance with § 98.34(a). If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per § 98.3(i). If 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. The following information shall be reported instead of the information in paragraph (b) of this section:

- (i) Common pipe identification number, beginning with the prefix "CP".
- (ii) The identification numbers of the units served by the common pipe.
- (iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).
- (iv) The fuels combusted in the units during the reporting year.
- (v) The methodology used to calculate the CO<sub>2</sub> mass emissions (i.e., Tier 1, Tier 2, or Tier 3).
- (vi) If the any of the units burns both fossil fuels and biomass, the annual CO<sub>2</sub> mass emissions from combustion of all fossil fuels and annual CO<sub>2</sub> emissions from combustion of all biomass fuels

from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH<sub>4</sub> and N<sub>2</sub>O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO<sub>2</sub>e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions), expressed in metric tons of CO<sub>2</sub>e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO<sub>2</sub> mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under § 75.64 of this chapter.

(ii) Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions at each monitored location, expressed in metric tons of CO<sub>2</sub>e.

(iii) Identification of the Part 75 methodology used to determine the CO<sub>2</sub> mass emissions.

(2) For units that use the alternative CO<sub>2</sub> mass emissions calculation methods for units with continuous monitoring systems 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, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, 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 40 CFR part 75 or 40 CFR 75.19:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO<sub>2</sub> mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions at each monitored location, across all fuel types, expressed in metric tons of CO<sub>2</sub>e.

(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 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO<sub>2</sub> mass emissions.

(C) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(D) The total annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions at each monitored location, expressed in metric tons of CO<sub>2</sub>e.

(e) *Verification data.* You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in § 98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required monitor and report CO<sub>2</sub> mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in § 98.33(a) to quantify CO<sub>2</sub> emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year.

Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO<sub>2</sub> emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a

measured value of a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO<sub>2</sub> mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the 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.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during the year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C-2b for each variable. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from § 98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content for each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO<sub>2</sub> mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO<sub>2</sub> concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO<sub>2</sub> emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio ("R") in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when CEMS are used to quantify the annual CO<sub>2</sub> emissions and biogenic CO<sub>2</sub> is determined according to § 98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO<sub>2</sub> emitted from the combustion of all fuels, i.e., V<sub>total</sub>, in scf.

(B) The annual volume of CO<sub>2</sub> emitted from the combustion of fossil fuels, i.e., V<sub>ff</sub>, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO<sub>2</sub> for each fuel separately as well as the total.

(C) The annual volume of CO<sub>2</sub> emitted from the combustion of biomass, i.e., V<sub>bio</sub>, in scf.

(D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO<sub>2</sub> per mmBtu.

(E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted,