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Mandatory Reporting of Greenhouse Gases; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 86, 87, 89, 90, 94, 98, 1033, 1039, 1042, 1045, 1048, 1051, 1054, 1065

[EPA–HQ–OAR–2008–0508; FRL–8963–5]

RIN 2060–A079

Mandatory Reporting of Greenhouse Gases

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating a regulation to require reporting of greenhouse gas emissions from all sectors of the economy. The final rule applies to fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters and manufacturers of heavy-duty and off-road vehicles and engines. The rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions.

DATES: The final rule is effective on December 29, 2009. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of December 29, 2009.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0508. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone number:* (202) 343–9263; *fax number:* (202) 343–2342; *e-mail address: GHGReportingRule@epa.gov.* For technical information and implementation materials, please go to the Web site *www.epa.gov/climatechange/emissions/ghgrulemaking.html.* You may also contact the Greenhouse Gas Reporting Rule Hotline at *telephone number:* (877) 444–1188; or *e-mail: ghgmrr@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine.''). The final rule affects fuel and chemicals suppliers, direct emitters of greenhouse gases (GHGs) and manufacturers of mobile sources and engines. Regulated categories and entities include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS	Examples of affected facilities
General Stationary Fuel Combustion Sources.	....	Facilities operating boilers, process heaters, incinerators, turbines, and internal combustion engines:
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.
Electricity Generation	221112	Fossil-fuel fired electric generating units, including units owned by Federal and municipal governments and units located in Indian Country.
Adipic Acid Production	325199	Adipic acid manufacturing facilities.
Aluminum Production	331312	Primary Aluminum production facilities.
Ammonia Manufacturing	325311	Anhydrous and aqueous ammonia manufacturing facilities.
Cement Production	327310	Portland Cement manufacturing plants.
Ferroalloy Production	331112	Ferroalloys manufacturing facilities.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
HCFC–22 Production and HFC–23 Destruction.	325120	Chlorodifluoromethane manufacturing facilities.
Hydrogen Production	325120	Hydrogen manufacturing facilities.
Iron and Steel Production	331111	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace shops.
Lead Production	331419	Primary lead smelting and refining facilities.
	331492	Secondary lead smelting and refining facilities.
Lime Production	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Nitric Acid Production	325311	Nitric acid manufacturing facilities.
Petrochemical Production	32511	Ethylene dichloride manufacturing facilities.
	325199	Acrylonitrile, ethylene oxide, methanol manufacturing facilities.
	325110	Ethylene manufacturing facilities.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
	325182	Carbon black manufacturing facilities.
Petroleum Refineries	324110	Petroleum refineries.
Phosphoric Acid Production	325312	Phosphoric acid manufacturing facilities.
Pulp and Paper Manufacturing	322110	Pulp mills.
	322121	Paper mills.
	322130	Paperboard mills.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing facilities.
Soda Ash Manufacturing	325181	Alkalies and chlorine manufacturing facilities.
	212391	Soda ash, natural, mining and/or beneficiation.
Titanium Dioxide Production	325188	Titanium dioxide manufacturing facilities.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust reclaiming facilities, recovering from scrap and/or alloying purchased metals.
Municipal Solid Waste Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
Manure Management	112111	Beef cattle feedlots.
	112120	Dairy cattle and milk production facilities.
	112210	Hog and pig farms.
	112310	Chicken egg production facilities.
	112330	Turkey Production.
	112320	Broilers and Other Meat type Chicken Production.
Suppliers of Coal Based Liquids Fuels	211111	Coal liquefaction at mine sites.
Suppliers of Petroleum Products	324110	Petroleum refineries.
Suppliers of Natural Gas and NGLs	221210	Natural gas distribution facilities.
	211112	Natural gas liquid extraction facilities.
Suppliers of Industrial GHGs	325120	Industrial gas manufacturing facilities.
Suppliers of Carbon Dioxide (CO_2)	325120	Industrial gas manufacturing facilities.
Mobile Sources	333618	Heavy-duty, non-road, aircraft, locomotive, and marine diesel engine manufacturing.
	336120	Heavy-duty vehicle manufacturing facilities.
	336312	Small non-road, and marine spark-ignition engine manufacturing facilities.
	336999	Personal watercraft manufacturing facilities.
	336991	Motorcycle manufacturing facilities.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Table 1 of this preamble lists the types of facilities that EPA is now aware could be potentially affected by the reporting requirements. Other types of facilities and suppliers not listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A or the relevant criteria in the sections related to manufacturers of heavy-duty and off-road vehicles and engines. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Many facilities that are affected by the final rule have GHG emissions from multiple source categories listed in Table 1 of this preamble. Table 2 of this preamble has been developed as a guide to help potential reporters subject to the mandatory reporting rule identify the source categories (by subpart) that they may need to (1) consider in their facility applicability determination, and (2) include in their reporting. For each source category, activity, or facility type (e.g., electricity generation, aluminum production), Table 2 of this preamble identifies the subparts that are likely to be relevant. The table should only be seen as a guide. Additional subparts may be relevant for a given reporter. Similarly, not all listed subparts are relevant for all reporters.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS

Source category (and main applicable subpart)	Other subparts recommended for review to determine applicability
General Stationary Fuel Combustion Sources.	
Electricity Generation	General Stationary Fuel Combustion, Suppliers of CO_2.
Adipic Acid Production	General Stationary Fuel Combustion.
Aluminum Production	General Stationary Fuel Combustion.
Ammonia Manufacturing	General Stationary Fuel Combustion, Hydrogen, Nitric Acid, Petroleum Refineries, Suppliers of CO_2.
Cement Production	General Stationary Fuel Combustion, Suppliers of CO_2.
Ferroalloy Production	General Stationary Fuel Combustion.
Glass Production	General Stationary Fuel Combustion.
HCFC–22 Production and HFC–23 Destruction	General Stationary Fuel Combustion.
Hydrogen Production	General Stationary Fuel Combustion, Petrochemicals, Petroleum Refineries, Suppliers of Industrial GHGs, Suppliers of CO_2.
Iron and Steel Production	General Stationary Fuel Combustion, Suppliers of CO_2.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS—Continued

Source category (and main applicable subpart)	Other subparts recommended for review to determine applicability
Lead Production	General Stationary Fuel Combustion.
Lime Manufacturing	General Stationary Fuel Combustion.
Nitric Acid Production	General Stationary Fuel Combustion, Adipic Acid.
Petrochemical Production	General Stationary Fuel Combustion, Ammonia, Petroleum Refineries.
Petroleum Refineries	General Stationary Fuel Combustion, Hydrogen, Suppliers of Petroleum Products.
Phosphoric Acid Production	General Stationary Fuel Combustion.
Pulp and Paper Manufacturing	General Stationary Fuel Combustion.
Silicon Carbide Production	General Stationary Fuel Combustion.
Soda Ash Manufacturing	General Stationary Fuel Combustion.
Titanium Dioxide Production	General Stationary Fuel Combustion.
Zinc Production	General Stationary Fuel Combustion.
Municipal Solid Waste Landfills	General Stationary Fuel Combustion.
Manure Management	General Stationary Fuel Combustion.
Suppliers of Coal-based Liquid Fuels	Suppliers of Petroleum Products.
Suppliers of Petroleum Products	General Stationary Fuel Combustion.
Suppliers of Natural Gas and NGLs	General Stationary Fuel Combustion, Suppliers of CO_2.
Suppliers of Industrial GHGs	General Stationary Fuel Combustion, Hydrogen Production, Suppliers of CO_2.
Suppliers of Carbon Dioxide (CO_2)	General Stationary Fuel Combustion, Electricity Generation, Ammonia, Cement, Hydrogen, Iron and Steel, Suppliers of Industrial GHGs.
Mobile Sources	General Stationary Fuel Combustion.

Judicial Review. Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by December 29, 2009. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

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

ARP Acid Rain Program
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
BLS Bureau of Labor Statistics
CAA Clean Air Act
CAFE Corporate Average Fuel Economy
CAIR Clean Air Interstate Rule
CARB California Air Resources Board
CBI confidential business information
CCAR California Climate Action Registry
CCS carbon capture and sequestration
CEMS continuous emission monitoring system(s)
cf cubic feet
CFCs chlorofluorocarbons
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
COD chemical oxygen demand
DOE U.S. Department of Energy
DOT U.S. Department of Transportation
EAF electric arc furnace
ECOS Environmental Council of the States
EGUs electric generating units
EIA Energy Information Administration
EO Executive Order
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FY2008 fiscal year 2008
GHG greenhouse gas
GWP global warming potential
HCFC–22 chlorodifluoromethane (or $CHClF_2$)
HCFCs hydrochlorofluorocarbons
HFC–23 trifluoromethane (or CHF_3)
HFCs hydrofluorocarbons
HFEs hydrofluorinated ethers
HHV higher heating value
ICR information collection request
IPCC Intergovernmental Panel on Climate Change
kg kilograms
LDCs local natural gas distribution companies
LMP lime manufacturing plants
mmBtu/hr millions British thermal units per hour
MSW municipal solid waste
MW megawatts
MY mileage year
N_2O nitrous oxide
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEI National Emissions Inventory
NESHAP national emission standards for hazardous air pollutants
NF_3 nitrogen trifluoride
NGLs natural gas liquids
NSPS new source performance standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act of 1995
O_3 ozone
ODS ozone-depleting substance(s)
OMB Office of Management and Budget
ORIS Office of Regulatory Information Systems
PFCs perfluorocarbons
PIN personal identification number
PSD Prevention of Significant Deterioration
QA quality assurance
QA/QC quality assurance/quality control
QAPP quality assurance performance plan
R&D research and development
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RICE reciprocating internal combustion engine
RIA regulatory impact analysis
SBREFA Small Business Regulatory Enforcement Fairness Act

scf standard cubic feet
SF_6 sulfur hexafluoride
SIP State Implementation Plan
SOP standard operating procedure
SSM startup, shutdown, and malfunction
TCR The Climate Registry
TRI Toxic Release Inventory
TSD technical support document
U.S. United States
UIC underground injection control
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
VMT vehicle miles traveled
VOC volatile organic compound(s)
WBCSD World Business Council for Sustainable Development
WCI Western Climate Initiative
WRI World Resources Institute
XML eXtensible Markup Language

Table of Contents

I. Background

A. Organization of This Preamble

This preamble is broken into several large sections, as detailed above in the Table of Contents. The paragraphs below describe the layout of the preamble and provide a brief summary of each section.

The first section of this preamble contains the basic background information about the origin of this rule, our legal authority, and how this proposal relates to other Federal, State, and regional efforts to address emissions of GHGs.

The second section of this preamble summarizes the general provisions of the final GHG reporting rule and identifies the major changes since proposal. It also provides a brief summary of public comments and responses on key design elements such as: (i) Source categories included, (ii) the level of reporting, (iii) applicability thresholds, (iv) selection of reporting and monitoring methods, (v) emissions verification, (vi) frequency of reporting and (vii) duration of reporting. It also addresses some of the legal comments on the statutory authority for the rule and the relationship of this rule to other CAA programs.

The third section of this preamble contains separate subsections addressing each individual source category of the proposed rule. Each source category section contains a summary of specific requirements of the rule for that source category, identifies major changes since proposal, and briefly discusses public comments and EPA responses specific to the source category. For example, comments on EPA's general approach for selecting monitoring methods are discussed in Section II of this preamble, whereas, comments on specific monitoring methods for individual source categories are discussed in Section III of this preamble.

The fourth section of this preamble summarizes rule requirements and addresses public comments pertaining to mobile sources.

The fifth section of this preamble explains how EPA plans to collect, manage and disseminate the data, while the sixth section describes the approach to compliance and enforcement. In both sections key public comments are summarized and responses are presented.

The seventh section provides the summary of the cost impacts, economic impacts, and benefits of the final rule and discusses comments on the regulatory impacts analyses. Finally, the last section discusses the various statutory and executive order requirements applicable to this rulemaking.

B. Background on the Final Rule

The fiscal year 2008 (FY2008) Consolidated Appropriations Act, signed on December 26, 2007, authorized funding for EPA to ''develop and publish a draft rule not later than nine months after the date of enactment of [the] Act, and a final rule not later than 18 months after the date of enactment of [the] Act, to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States.'' Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128 (2008).

The accompanying joint explanatory statement directed EPA to ''use its existing authority under the Clean Air Act'' to develop a mandatory GHG reporting rule. ''The Agency is further directed to include in its rule reporting of emissions resulting from upstream production and downstream sources, to the extent that the Administrator deems it appropriate.'' EPA interpreted that language to confirm that it was appropriate for the Agency to exercise its CAA authority to develop this rulemaking. The joint explanatory statement further states that ''[t]he Administrator shall determine appropriate thresholds of emissions above which reporting is required, and how frequently reports shall be submitted to EPA. The Administrator shall have discretion to use existing reporting requirements for electric generating units (EGUs)'' under section 821 of the 1990 CAA Amendments.

On April 10, 2009 (74 FR 16448), EPA proposed the GHG reporting rule. EPA held two public hearings, and received approximately 16,800 written public comments. The public comment period ended on June 9, 2009.

In addition to the public hearings, EPA had an open door policy, similar to the outreach conducted during the development of the proposal. As a result, EPA has met with over 4,000 people and 135 groups since proposal signature (March 10, 2009). Details of these meetings are available in the docket (EPA–HQ–OAR–2008–0508).

EPA developed this final rule and included reporting of GHGs from the facilities that we determined appropriately responded to the direction in the FY2008 Consolidated Appropriations Act [1] (e.g., capturing approximately 85 percent of U.S. GHG emissions through reporting by direct emitters as well as suppliers of fossil fuels and industrial gases and manufacturers of heavy-duty and off-road vehicles and engines). There are, however, many additional types of data and reporting that the Agency deems important and necessary to address an issue as large and complex as climate change (e.g., indirect emissions, electricity use). In that sense, one could view this final rule as narrowly focused on certain sources of emissions and upstream suppliers. As described in Sections I.C and D of this preamble as well as in the comment response sections, there are several existing programs at the Federal, regional and State levels that also collect valuable information to inform and implement policies necessary to address climate change. Many of these programs are focused on cost-effectively reducing GHG emissions through improvements in energy efficiency and by other means. These programs are an essential component of the Nation's climate policy, and the targeted nature of this rule should not be interpreted to mean that the data EPA collects through this program are the only data necessary to support the full range of climate policies and programs.

Today's rule requires the reporting of the GHG emissions that could result from the combustion or use of fossil fuel or industrial gas that is produced or imported from upstream sources such as fuel suppliers, as well as reporting of GHG emissions directly emitted from facilities (downstream sources) through their processes and/or from fuel combustion, as appropriate. Vehicle and engine manufacturers are also required to report emissions rate data on the heavy-duty and off-road engines they produce. The rule also establishes appropriate thresholds and frequency for reporting.

The rule requires reporting of annual emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated gases (e.g., nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFEs)). It also includes provisions to ensure the accuracy of emissions data through monitoring, recordkeeping and verification requirements. The rule applies to certain downstream facilities that emit GHGs (primarily large facilities emitting 25,000 metric tons or more of CO_2 equivalent (CO_2e) GHG emissions per year) and to most upstream suppliers of fossil fuels and industrial GHGs, as well as to manufacturers of vehicles and engines. Reporting is at the facility level, except certain suppliers and vehicle and engine manufacturers report at the corporate level.

C. Legal Authority

As proposed, EPA is promulgating this rule under its existing CAA authority, specifically authorities provided in CAA sections 114 and 208. As discussed further below and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues'', we are not citing the FY 2008 Consolidated Appropriations Act as the statutory basis for this action. While that law required that EPA spend no less than $3.5 million on a rule requiring the mandatory reporting of GHG emissions, it is the CAA, not the Appropriations Act, that EPA is citing as the authority to gather the information required by this rule.

Sections 114 and 208 of the CAA provide EPA broad authority to require the information mandated by this rule because such data will inform and are relevant to EPA's carrying out a wide variety of CAA provisions. As discussed in the proposed rule, CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA (except for a provision of title II with respect to manufacturers of new motor vehicles or

[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG reporting rule, and provided additional funding, in the 2009 Appropriations Act (Consolidated Appropriations Act, 2009, Public Law 110–329, 122 Stat. 3574–3716).

new motor vehicle engines).[2] Section 208 of the CAA provides EPA with similar broad authority regarding the manufacturers of new motor vehicles or new motor vehicle engines, and other persons subject to the requirements of parts A and C of title II. We note that while climate change legislation approved by the U.S. House of Representatives would provide EPA additional authority for a GHG registry similar to today's rule, and would do so for purposes of that pending legislation, this final rule is authorized by, and the information being gathered by the rule is relevant to implementing, the existing CAA. We expect, however, that the information collected by this final rule will also prove useful to legislative efforts to address GHG emissions.

As discussed in the proposal, emissions from direct emitters should inform decisions about whether and how to use CAA section 111 to establish new source performance standards (NSPS) for various source categories emitting GHGs, including whether there are any additional categories of sources that should be listed under CAA section 111(b). Similarly, the information required of manufacturers of mobile sources should support decisions regarding treatment of those sources under CAA sections 202, 213 or 231. In addition, the information from fuel suppliers would be relevant in analyzing whether to proceed, and particular options for how to proceed, under CAA section 211(c) regarding fuels, or to inform action concerning downstream sources under a variety of Title I or Title II provisions. The data overall also would inform EPA's implementation of CAA section 103(g) regarding improvements in non-regulatory strategies and technologies for preventing or reducing air pollutants (e.g., EPA's voluntary GHG reduction programs such as the non-CO_2 partnership programs and ENERGY STAR, described below in Section I.D of this preamble and Section II of the proposal preamble (74 FR 16448, April 10, 2009)).

D. How does this rule relate to EPA and U.S. government climate change efforts?

This reporting rule is one specific action EPA has taken, consistent with the Congressional request contained in the FY2008 Consolidated Appropriations Act, to collect GHG emissions data. EPA has recently announced a number of climate change related actions, including proposed findings that GHG emissions from new motor vehicles and engines contribute to air pollution which may reasonably be anticipated to endanger public health and welfare (74 FR 18886, April 24, 2009, ''Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act''), and an intent to regulate light duty vehicles, jointly published with U.S. Department of Transportation (DOT) (74 FR 24007, May 22, 2009, ''Notice of Upcoming Joint Rulemaking To Establish Vehicle GHG Emissions and CAFE Standards''). The Administrator has also announced her reconsideration of the memo entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (73 FR 80300, December 31, 2008), and granted California's request for a waiver for its GHG vehicle standard (74 FR 32744, July 8, 2009). These are all separate actions, some of which are related to EPA's response to the U.S. Supreme Court's decision in *Massachusetts* v. *EPA*. 127 S. Ct. 1438 (2007). This rulemaking does not indicate EPA has made any final decisions on pending actions. In fact the mandatory GHG reporting program will provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions, which should assist in future policy development.

Accurate and timely information on GHG emissions is essential for informing many future climate change policy decisions. Although additional data collection (e.g., for other source categories or to support additional policy or program needs) will no doubt be required as the development of climate policies evolves, the data collected in this rule will provide useful information for a variety of polices. Through data collected under this rule, EPA, States and the public will gain a better understanding of the relative emissions of specific industries across the nation 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 could in the future or already take to reduce emissions, including under traditional and more flexible programs.

As discussed in more detail in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues'' and elsewhere, EPA is promulgating this rule to gather GHG information to assist EPA in assessing how to address GHG emissions and climate change under the Clean Air Act. However, we expect that the information will prove useful for other purposes as well. For example, using the rich data set provided by this rulemaking, EPA, States and the public will be able to track emission trends from industries and facilities within industries over time, particularly in response to policies and potential regulations. The data collected by this rule will also improve the U.S. government's ability to formulate climate policies, and to assess which industries might be affected, and how these industries might be affected by potential policies. Finally, EPA's experience with other reporting programs is that such programs raise awareness of emissions among reporters and other stakeholders, and thus contribute to efforts to identify and implement emission reduction opportunities. These data can also be coupled with efforts at the local, State and Federal levels to assist corporations and facilities in determining their GHG footprints and identifying opportunities to reduce emissions (e.g., through energy audits or other forms of assistance).

This GHG reporting program supplements and complements, rather than duplicates, existing U.S. government programs (e.g., climate policy and research programs). For example, EPA anticipates that facility-level GHG emissions data will lead to improvements in the quality of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory), which EPA prepares annually, with input from several other agencies, and submits to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC).

A number of EPA voluntary partnership programs include a GHG emissions and/or reductions reporting component (e.g., Climate Leaders, the Natural Gas STAR program, Energy Star). This mandatory reporting program has broader coverage of U.S. GHG emissions than most voluntary programs, which typically focus on a specific industry and/or goal (e.g., reduction of CH_4 emissions or development of corporate inventories). It will improve EPA's understanding of emissions from facilities not currently included in these programs and increase the coverage of these industries. That said, we expect ongoing and potential new voluntary programs to continue to

[2] Although there are exclusions in CAA section 114(a)(1) regarding certain title II requirements applicable to manufacturers of new motor vehicle and motor vehicle engines, CAA section 208 authorizes the gathering of information related to those areas.

play an important role in achieving low-cost reductions in GHG emissions.

In addition to EPA's programs mentioned above, U.S. Department of Energy (DOE) EIA implements a voluntary GHG registry under section 1605(b) of the Energy Policy Act, which is further discussed in Section II of the proposal preamble (74 FR 16458, April 10, 2009). Under EIA's ''1605(b) program,'' reporters can choose to prepare an entity-wide GHG inventory and identify specific GHG reductions made by the entity.[3] EPA's mandatory GHG reporting rule covers a much broader set of reporters, primarily at the facility rather than entity-level, but this reporting rule is not designed with the specific intent of reporting of emission reductions, as is the 1605(b) program.

For additional information about these programs, *please see* Sections I and II of the preamble to the proposed GHG reporting rule (74 FR 16454, April 10, 2009).

E. How does this rule relate to other State and Regional Programs?

There are several existing State and regional GHG reporting and/or reduction programs summarized in Section II of the proposal preamble (74 FR 16457, April 10, 2009). These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also assist in quantifying the GHG reductions achieved by various policies. Many of these programs collect different or additional data as compared to this rule. For example, State programs may establish lower thresholds for reporting or request information on areas not addressed in EPA's reporting rule (e.g., electricity use or emission related to other indirect sources). States collecting additional information have determined that these data are necessary to implement their specific climate policies and programs. EPA agrees that State and regional programs are crucial to achieving emissions reductions, and this rule does not preempt any other programs.

EPA's GHG reporting rule is a specific single action that was developed in response to the Appropriations Act, and therefore is targeted to accomplish the purpose of the language of the Appropriations Act and serve EPA's purposes under the CAA. As State experience has demonstrated, we recognize that in order to address the breadth of climate change issues there will likely be a need to collect additional data from sources subject to this rule as well as other sources. The timing and nature of these additional needs will be dependent on the types of programs and actions the Agency has underway or may develop and implement in response to future policy developments and/or new requests from Congress. Addressing climate change will require a suite of policies and programs and this reporting rule is just one effort to collect information to inform those policies.

EPA is committed to working with State and regional programs to coordinate implementation of reporting programs, reduce burden on reporters, provide timely access to verified emissions data, establish mechanisms to efficiently share data, and harmonize data systems to the extent possible. See Section II.O of this preamble for a summary of public comments and responses on the role of States and the relationship of this GHG reporting rule to other programs. See Section VI.B of this preamble for a summary of comments and responses on State delegation of rule implementation and enforcement. As mentioned above, for additional information about existing State and regional programs *please see* Section II of the proposal preamble (74 FR 16457, April 10, 2009) and the docket EPA–HQ–OAR–2008–0508.

II. General Requirements of the Rule

The rule requires reporting of annual emissions of CO_2, CH_4, N_2O, SF_6, HFCs, PFCs, and other fluorinated gases (as defined in 40 CFR part 98, subpart A) in metric tons. The final 40 CFR part 98 applies to certain downstream facilities that emit GHGs, and to certain upstream suppliers of fossil fuels and industrial GHGs. For suppliers, the GHG emissions reported are the emissions that would result from combustion or use of the products supplied. The rule also includes provisions to ensure the accuracy of emissions data through monitoring, recordkeeping and verification requirements. Reporting is at the facility[4] level, except that certain suppliers of fossil fuels and industrial gases would report at the corporate level.

In addition, GHG reporting by manufacturers of heavy-duty and off-road vehicles and engines is required, by incorporating new requirements into the existing reporting requirements for motor vehicles and engine manufacturers in 40 CFR parts 86, 87, 89, 90, 94, 1033, 1039, 1042, 1045, 1048, 1051, 1054, and 1065. A summary of the reporting requirements for manufacturers of motor vehicles and engines is contained in Section IV of this preamble. A discussion of public comments and responses that pertain to motor vehicles is also contained in Section IV of this preamble and in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Motor Vehicle and Engine Manufacturers.''

The remainder of this section summarizes the general provisions of 40 CFR part 98, identifies changes since the proposed rule, and summarizes key public comments and responses on the general requirements of the rule.

A. Summary of the General Requirements of the Final Rule

1. Applicability

Reporters must submit annual GHG reports for the following facilities and supply operations.

- Any facility that contains any source category (as defined in 40 CFR part 98, subparts C through JJ) that is listed below in any calendar year starting in 2010.[5] For these facilities, the annual GHG report covers all source categories and GHGs for which calculation methodologies are provided in 40 CFR part 98, subparts C through JJ.

—Electricity generating facilities that are subject to the Acid Rain Program (ARP) or otherwise report CO_2 mass emissions year-round through 40 CFR part 75.
—Adipic acid production.
—Aluminum production.
—Ammonia manufacturing.
—Cement production.
—HCFC–22 production.
—HFC–23 destruction processes that are not co-located with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.
—Lime manufacturing.
—Nitric acid production.
—Petrochemical production.
—Petroleum refineries.

[3] Under the 1605(b) program an ''entity'' is defined as ''the whole or part of any business, institution, organization or household that is recognized as an entity under any U.S. Federal, State or local law that applies to it; is located, at least in part, in the U.S.; and whose operations affect U.S. greenhouse gas emissions.'' (*http://www.pi.energy.gov/enhancingGHGregistry/*)

[4] For the purposes of this rule, 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.

[5] Unless otherwise noted, years and dates in this notice refer to calendar years and dates.

—Phosphoric acid production.
—Silicon carbide production.
—Soda ash production.
—Titanium dioxide production.
—Municipal solid waste (MSW) landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to 40 CFR part 98, subpart HH.
—Manure management systems that emit CH_4 and N_20 (combined) in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to 40 CFR part 98, subpart JJ.

• Any facility that contains any source category (as defined in 40 CFR part 98, subparts C through JJ) that is listed below and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous use of carbonates and all of the source categories listed in this paragraph 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 40 CFR part 98, subparts C through JJ.

—Ferroalloy Production.
—Glass Production.
—Hydrogen Production.
—Iron and Steel Production.
—Lead Production.
—Pulp and Paper Manufacturing.
—Zinc Production.

• Any facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph. For these facilities, the annual GHG report covers emissions from stationary fuel combustion sources only. For 2010 only, the facilities can submit an abbreviated GHG report according to 40 CFR 98.3(d).

—The facility does not meet the requirements described in the above two paragraphs;
—The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 million British thermal units per hour (mmBtu/hr) or greater; and
—The facility emits 25,000 metric tons CO_2e or more per year from all stationary fuel combustion sources.[6]

• Any supplier (as defined in 40 CFR part 98, subparts LL through PP) of any of the products as listed below in any calendar year starting in 2010. For these suppliers, the annual GHG report covers all applicable products for which calculation methodologies are provided in 40 CFR part 98, subparts KK through PP.

—*Coal-based liquid fuels:* All producers of coal-to-liquid fuels; importers and exporters of coal-to-liquid fuels with annual imports or annual exports that are equivalent to 25,000 metric tons CO_2e or more per year.
—*Petroleum products:* All petroleum refiners that distill crude oil; importers and exporters of petroleum products with annual imports or annual exports that are equivalent to 25,000 metric tons CO_2e or more per year.
—*Natural gas and natural gas liquids (NGLs):* All natural gas fractionators and all local natural gas distribution companies (LDCs).
—*Industrial GHGs:* All producers of industrial GHGs; importers and exporters of industrial GHGs with annual bulk imports or exports of N_2O, fluorinated GHGs, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more per year.
—*CO_2:* All producers of CO_2; importers and exporters of CO_2 with annual bulk imports or exports of N_2O, fluorinated GHGs, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more per year.

• Research and development activities (as defined in 40 CFR 98.6) are not considered to be part of any source category subject to the rule.

It is important to note that the applicability criteria apply to a facility's annual emissions or a supplier's annual quantity of product supplied.[7] For example, while a facility's emissions may be below 25,000 metric tons CO_2e in January, if the cumulative emissions for the calendar year are 25,000 metric tons CO_2e or more at the end of December, the rule applies and the reporter must submit an annual GHG report for that facility. Therefore, it is in a facility's or supplier's interest to collect the GHG data required by the rule if they think they will meet or exceed the applicability criteria in 40 CFR 98.2 by the end of the year. EPA plans to have tools and guidance available to assist potential reporters in assessing whether the rule applies to their facilities or supply operations.

2. Schedule for Reporting

Reporters must begin collecting data on January 1, 2010. The first annual GHG report is due on March 31, 2011, for GHGs emitted or products supplied during 2010. For a portion of 2010, the rule allows reporters to use best available monitoring methods for parameters that cannot reasonably be measured according to the monitoring and quality assurance/quality control (QA/QC) requirements of the relevant subpart as described in Sections II.A.3 and II.G of this preamble.

Reports are submitted annually. For EGUs that are subject to the ARP, reporters must continue to report CO_2 mass emissions quarterly, as required by the ARP, in addition to providing annual GHG reports under this rule. Reporters must submit GHG data on an ongoing, annual basis. The snapshot of information provided by a one-time information collection request (ICR) would not provide the type of ongoing information which could inform the variety of potential CAA policy options being evaluated for addressing climate change.

Once subject to this reporting rule, reporters must continue to submit GHG reports annually. A reporter can cease reporting if the required annual GHG reports demonstrate that reported GHG emissions are either (1) less than 25,000 metric tons of CO_2e per year for five consecutive years or (2) less than 15,000 metric tons of CO_2e per year for three consecutive years. The reporter must notify EPA that they intend to cease reporting and explain the reasons for the reduction in emissions. This provision applies to all facilities and suppliers subject to the rule, regardless of their applicability category (i.e., whether rule applicability was initially triggered by an ''all-in'' source category or a source category with a 25,000 metric tons CO_2e threshold). The reporter must keep records for all five consecutive years in which emissions were less than 25,000 metric tons per year, or all three consecutive years in which emissions were less than 15,000 metric tons per year, as appropriate. If GHG emissions (or quantities in products supplied) subsequently increase to 25,000 metric tons CO_2e in any calendar year, the reporter must again begin annual reporting. The rule also contains a provision to allow facilities and suppliers to notify EPA and stop reporting if they close all GHG-emitting processes and operations covered by the rule.

If reporters discover or are notified by EPA of errors in an annual GHG report, they must submit a revised GHG report within 45 days.

3. What has to be included in the annual GHG report?

Reporters must include the following information in each annual GHG report:

[6] This does not include portable equipment, emergency generators, or emergency equipment as defined in the rule.

[7] Supplied means produced, imported, or exported.

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

• Year and months covered by the report, and date of report submittal.

• For facilities that directly emit GHG:

—Annual facility emissions (excluding biogenic CO_2), expressed in metric tons of CO_2e per year, aggregated for all GHG from all source categories in 40 CFR part 98, subparts C through JJ that are located at the facility.

—Annual emissions of biogenic CO_2 (i.e., CO_2 from combustion of biomass) aggregated for all applicable source categories in subparts C through JJ located at the facility.

—Annual GHG emissions for each of the source categories located at the facility, by gas. Gases are: CO_2 (excluding biogenic CO_2), biogenic CO_2, CH_4, N_2O, and each fluorinated GHG.

—Within each source category, emissions broken out at the level specified in the respective subpart (e.g., some source categories require reporting for each individual unit or each process line).

—Additional data specified in the applicable subparts for each source category. This includes activity data (e.g., fuel use, feedstock inputs) that were used to generate the emissions data and additional data to support QA/QC and emissions verification.

—Total pounds of synthetic fertilizer produced through nitric acid or ammonia production and total nitrogen contained in that fertilizer.

• For suppliers: [8]

—Annual quantities of each GHG that would be emitted from combustion or use [9] of the products supplied, imported, or exported during the year. Report this for each applicable supply category in 40 CFR part 98 subparts KK through PP, by gas. Also report the total quantity, expressed in metric tons of CO_2e, aggregated for all GHGs from all applicable supply categories.

—Additional data specified in the applicable subparts for each supply category. This includes data used to calculate GHG quantities or needed to support QA/QC and verification.

• A written explanation if the reporter changes GHG calculation methodologies during the reporting period.

• If best available monitoring methods were used for part of calendar year 2010, a brief description of the methods used.

• 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.

• A signed and dated certification statement provided by the Designated Representative of the owner or operator.

Note that in some cases, the same facility is subject to the rule requirements for direct emitters as well as for suppliers. For example, petroleum refineries are suppliers of petroleum products (40 CFR part 98, subpart NN) and also directly emit GHGs from petroleum refining (40 CFR part 98, subpart Y), general stationary fuel combustion (40 CFR part 98, subpart C), and possibly other source categories located at a refinery. In such cases, reporters must report the information in both the facility and supplier bullets listed above.

EPA will protect any information claimed as CBI in accordance with regulations in 40 CFR part 2, subpart B. However, note that in general, emission data collected under CAA sections 114 and 208 shall be available to the public and cannot be withheld as CBI.[10]

Special Provisions for Reporting Year 2010. During January 1, 2010 through March 31, 2010, reporters 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 reporter must still 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 reporter must begin following all applicable monitoring and QA/QC requirements of this part, unless they submit a request to EPA showing that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010, and EPA approves the request. EPA will not approve use of best available methods beyond December 31, 2010. Best available monitoring methods include any of the following methods:

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

• Supplier data.

• Engineering calculations.

• Other company data.

Abbreviated GHG Report for Facilities Containing Only General Stationary Fuel Combustion Sources. In lieu of a full annual GHG report, reporters may submit an abbreviated GHG report for 2010 emissions from existing facilities that were in operation as of January 1, 2010, and are required to report only their stationary combustion source emissions per 40 CFR 98.2(a)(3). The abbreviated report contains total facility GHG emissions aggregated for all stationary combustion units calculated according to any of the methods in 40 CFR 98.33(a) and expressed in metric tons of CO_2, CH_4, N_2O, and CO_2e. While the breakdown of emissions by individual combustion units and the activity data used to calculate the emissions do not need to be reported as part of the abbreviated GHG report, the calculation variables used in the selected method must be reported. For calendar year 2011, all reporters must submit the full annual GHG report containing all required information.

4. How is the report submitted?

The reports must be submitted electronically, in a format to be specified by the Administrator after publication of the final rule.[11] To the extent practicable, we plan to adapt existing EPA facility reporting programs to accept GHG emissions data. We are developing a new electronic data reporting system for source categories or suppliers for which it is not feasible to use existing EPA reporting mechanisms.

Each report must contain a signed certification by a Designated Representative of the facility. On behalf of the owners and operators, the Designated Representative must certify under penalty of law that the report has been prepared in accordance with the requirements of 40 CFR part 98 and that the information contained in the report is true and accurate.

5. What records must be retained?

Each reporter must also retain and make available to EPA upon request the

[8] Suppliers include producers, importers, and exporters of fuels and industrial gases. The level of reporting for suppliers is specified in the rule. Most report at the facility level. Imports and exports are reported at the corporate level.

[9] ''Use'' for purposes of industrial GHGs presumes that there will be 100 percent release of the GHG.

[10] Although CBI determinations are usually made on a case-by-case basis, EPA has discussed in an earlier **Federal Register** notice what constitutes emissions data that cannot be withheld as CBI (956 FR 7042–7043, February 21, 1991). In addition, as discussed in Section II.R of this preamble, EPA will be initiating a separate notice and comment process to make CBI and emissions data determinations for the categories of data collected under this rulemaking.

[11] For more information about the reporting format please see Section V of this preamble.

following records for three years in an electronic or hard-copy format as appropriate:

• A list of all units, operations, processes and activities for which GHG emissions are calculated.

• 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 GHG emissions calculations and methods used.
—Analytical results for the development of site-specific emissions factors.
—The results of all required analyses for high heat value, carbon content, or other required fuel or feedstock parameters.
—Any facility operating data or process information used for the GHG emissions calculations.

• The annual GHG reports.

• 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.

• A written GHG monitoring plan containing the information specified in 40 CFR 98.3(g)(5).

• The results of all required certification and quality assurance (QA) tests of CEMS, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

• Maintenance records for all CEMS, flow meters, and other instrumentation used to provide data for the GHGs reported.

• Any other data specified in any applicable subpart of 40 CFR part 98. Examples of such data could include the results of sampling and analysis procedures required by the subparts (e.g., fuel heat content, carbon content of raw materials, and flow rate) and other data used to calculate emissions.

B. Summary of the Major Changes Since Proposal

EPA received approximately 16,800 public comments on the proposed rulemaking. As mentioned earlier in this preamble, we had two public hearings and conducted an unprecedented level of outreach between signature of the proposal and the close of the public comment period. Below are the major changes to the program since the proposal. The rationale for these and any other significant changes can be found in this preamble or in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.''

• Reduced the number of source categories included in the final rule as we further consider comments and options on several categories.[12]

• Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that report less than 25,000 metric tons of CO_2e for five consecutive years, or less than 15,000 metric tons for 3 consecutive years, to cease annual reporting to EPA.

• Added a mechanism in 40 CFR 98.2 to allow facilities and suppliers that stop operating all GHG-emitting processes and operations covered by the rule to cease annual reporting to EPA.

• Added a provision in 40 CFR 98.3 for submittal of revised annual GHG reports to correct errors.

• Added provisions in 40 CFR 98.3 to allow use of best available monitoring methods for part of calendar year 2010.

• Added, in 40 CFR 98.3, calibration requirements for monitoring instruments including an accuracy specification of plus or minus five percent for flow meters.

• Excluded R&D activities from reporting under 40 CFR part 98 by adding an exclusion in 40 CFR 98.2.

• Revised the requirements of the Designated Representative in 40 CFR 98.4 to align them with those in 40 CFR part 75 (ARP regulations).

• Changed record retention to three years instead of five years for most records (40 CFR 98.3).

• In the recordkeeping section (40 CFR 98.3), clarified the contents of the monitoring plan (called the quality assurance performance plan (QAPP) at proposal).

• Edited references to the stationary fuel combustion subpart to improve consistency and edited the CEMS language in several subparts for consistency and to clarify when CEMS are used and under what circumstances upgrades are needed.

• Revised several definitions in 40 CFR part 98, subpart A to address comments.

• In several subparts of 40 CFR part 98, moved some of the data elements listed in the recordkeeping section of the proposed rule to the reporting section. In general, these changes were made to provide sufficient data for EPA to verify the reported emissions using the verification approach described in Section II.N of this preamble. Specific changes and reasons for them are summarized in the relevant source category sections within Section III of this preamble.

C. Summary of Comments and Responses on GHGs To Report

This section contains a brief summary of major comments and responses on the issue of which GHGs to report. A large number of comments 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, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.'' Reponses to comments on fluorinated gases can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Suppliers of Industrial GHGs.''

Comment: Many commenters supported reporting of the GHGs included in the proposed rule: CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and other fluorinated compounds. Many commenters noted that IPCC and national inventories focus on these gases, and that they are directly emitted by human activities, long-lived in the atmosphere, and contribute to global climate change. A few of these also stated that collection of data on these gases is useful for future GHG policy development. While some commenters suggested collecting data on fewer gases or requiring reporting of additional gases, most agreed with the proposed list.

Some commenters raised concerns that the proposed definition of fluorinated GHGs was broad and included compounds for which global warming potentials (GWPs) were not currently available.

Response: The final rule requires reporting of the same gases as the proposed rule. These are the most abundantly emitted GHGs that result from human activity. They are not currently controlled by mandatory Federal programs and, with the exception of the CO_2 emissions data reported by EGUs subject to the ARP, data on their emissions are also not reported under mandatory Federal programs. CO_2 is the most abundant GHG directly emitted by human activities, and is a significant driver of climate change. The global anthropogenic combined heating effect of CH_4, N_2O, HFCs, PFCs, SF_6, and the other fluorinated compounds are also

[12] See the following sections of this preamble for discussion of source categories not included in today's final rule: sections III.I (electronics manufacturing), III.J (ethanol production), III.L (fluorinated GHG production), III.M (food processing), III.T (magnesium production), III.W (oil and natural gas systems), III.DD (SF_6 from electrical equipment), III.FF (underground coal mines), III.HH (industrial landfills are not included in today's rule, but MSW landfills are covered by the rule), III.II (wastewater treatment), and III.KK (suppliers of coal).

significant: About 40 percent as large as the CO_2 heating effect according to the Fourth Assessment Report of the IPCC.

The IPCC focuses on CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 for both scientific assessments and emissions inventory purposes because these are long-lived, well-mixed GHGs not controlled by the Montreal Protocol as Substances that Deplete the Ozone (O_3) Layer. These GHGs are directly emitted by human activities, are reported annually in EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, and are a major focus of the climate change research and policy communities. The IPCC also included methods for accounting for emissions from several specified fluorinated gases in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[13] These gases include fluorinated ethers, which are used in electronics, in anesthetics, and as heat transfer fluids. These fluorinated compounds are long-lived in the atmosphere and have high GWPs, like the HFCs, PFCs, and SF_6. In many cases these fluorinated gases are used in growing industries (e.g., electronics) or as substitutes for HFCs. As such, EPA is requiring reporting of these gases to ensure that the Agency has an accurate understanding of the emissions and uses of these gases, particularly as those uses expand.

There are other GHGs and aerosols that have climatic warming effects that we are not including in this rule: water vapor, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), halons, tropospheric O_3, and black carbon. The reasons why we are not requiring reporting of these gases and aerosols under this rule are contained in Section IV.A of the preamble to the proposed rule (74 FR 16464, April 10, 2009) and in the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.''

In response to comments, the definition of fluorinated gases to report has been changed. See Section III.OO of this preamble (Suppliers of Industrial GHGs) for the response to comments on fluorinated gases to be reported.

[13] 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The National Greenhouse Gas Inventories Programme, H.S. Eggleston, L. Buendia, K. Miwa, T. Ngara, and K. Tanabe (eds), hereafter referred to as the ''2006 IPCC Guidelines'' are found at: *http://www.ipcc.ch/ipccreports/methodology-reports.htm*. For additional information on these gases please see Table A–1 in proposed 40 CFR part 98, subpart A and the Suppliers of Industrial GHGs TSD (EPA–HQ–OAR–2008–0508–041).

D. Summary of Comments and Responses on Source Categories To Report

This section contains a brief summary of major comments and responses on which source categories must report. A large number of comments 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, Selection of Source Categories to Report and Level of Reporting.''

1. Reduction in Number of Source Categories Included in the Final Rule

Comment: While many commenters agreed with the source categories selected for inclusion in the proposed rule, some commenters objected to the inclusion of specific source categories. Some also expressed concern that there might not be sufficient time for EPA to consider and address public comments and finalize the rules by fall 2009 for particular source categories.

Response: In today's notice EPA is promulgating subparts that require reporting for most of the source categories included in the proposed rule. For these categories, EPA fully considered and addressed the public comments, and has determined that the source categories should be included in the rule for reasons stated in Section IV.B of the preamble for the proposed rule (74 FR 16465, April 10, 2009), the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'', and the relevant comment response volumes for each of the individual source categories. However, at this time EPA is not going final with the following subparts as we further evaluate public comments:

- Electronics manufacturing
- Ethanol production
- Fluorinated GHG production
- Food processing
- Magnesium production
- Oil and natural gas systems
- SF_6 from electrical equipment
- Underground coal mines
- Industrial landfills
- Wastewater treatment
- Suppliers of coal

We plan to further review public comments and other information before finalizing these subparts. Additional discussion of our reasons for not finalizing these particular source categories at this time can be found in the individual subsections in Section III of this preamble.

2. Scope of Source Categories Covered

Comment: Several commenters suggested that the scope of reporting and the source categories covered should be broader. Some indicated that the rule should require reporting of net rather than gross emissions, including reporting of offset projects. In addition, some of the comments suggested requiring reporting of emissions and sequestration from forestry practices.

Response: EPA selected the source categories required to report under the rule after considering the language of the Appropriations Act, the accompanying explanatory statement, the CAA, and EPA's experience in developing the U.S. GHG Inventory. The Appropriations Act referred to reporting ''in all sectors of the economy,'' and the explanatory statement directed EPA to include ''emissions from upstream production and downstream sources to the extent the Administrator deems it appropriate.'' EPA interpreted this to mean direct emissions from facilities over a certain threshold as well as the emissions associated with fuel or industrial gases when completely combusted or used, but not necessarily project-based reductions or sequestration.[14] Calculation and reporting of net emissions (emissions at a facility less any sequestration occurring at the facility) was determined to be outside of the scope of this rule.

In selecting source categories, EPA considered all anthropogenic sources of GHG emissions (those produced as a result of human activities) included in the U.S. GHG Inventory and reviewed the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and existing voluntary and regulatory GHG reporting programs for additional source categories that might be relevant. EPA systematically reviewed the list of source categories developed from the U.S. GHG Inventory and the IPCC guidance to ensure the inclusion of those that emit the most significant amounts of GHG emissions while minimizing the number of reporters. Some sources were deemed inappropriate for inclusion in this rule for a variety of reasons including the current ability to monitor and verify the emissions or products with sufficient accuracy and consistency. For further discussions of sources included and excluded please see Section IV.B of the preamble to the proposed rule (74 FR 16465). In total, the rule is estimated to

[14] For the discussion of the CAA authority to collect these data, *see* Section II.Q of this preamble. Also see the relevant source category sections within Section III of this preamble.

cover approximately 85 percent of U.S. GHG emissions.

With respect to emissions and sequestration from agricultural sources and other land uses, the rule does not require reporting of emissions or sequestration associated with deforestation, carbon storage in living biomass or harvested wood products. These categories were excluded because currently available, practical reporting methods to calculate facility-level emissions for these sources can be difficult to implement and can yield uncertain results. Currently, there are no direct GHG emission measurement methods available except for research methods that are very expensive and require sophisticated equipment. Limited modeling-based methods have been developed for voluntary GHG reporting protocols which use general emission factors, and large-scale models have been developed to produce comprehensive national-level emissions estimates, such as those reported in the U.S. GHG Inventory report. To calculate emissions or sequestration using emission factor or carbon stock exchange approaches, it would be necessary for landowners to report on management practices and a variety of data inputs. The activity data collection and emission factor development necessary for emissions calculations at the scale of individual reporters can be complex and costly. Due to the current lack of reasonably accurate facility-level emissions/stock change factors and the ability to accurately measure all facility-level calculation variables at a reasonable cost to reporters, the reporting of emissions and sequestration associated with deforestation and carbon sequestration from forestry practices was excluded as a source category.

While this reporting rule does not require reporting by facilities or suppliers in every source category, the U.S. GHG Inventory does provide national estimates of emissions from all U.S. anthropogenic GHG sources. In the case of land-based emissions, this includes all emissions by sources and removals by sinks on lands that are managed. The Inventory is prepared annually by EPA, in collaboration with other Federal agencies, and is an impartial, policy-neutral report that tracks annual GHG emissions at the national level and presents historical emissions from 1990 to 2007. The Inventory also calculates carbon dioxide emissions that are removed from the atmosphere by ''sinks,'' such as through the uptake of carbon by forests, vegetation, and soils.

Offsets projects are of interest to many stakeholders because they could be an important component of a potential future cap and trade system. Some commenters requested EPA to include accounting methods for offsets in this reporting rule. We believe that this issue is beyond the scope of this rulemaking and the Congressional request that initiated it. However, EPA will continue to monitor policy needs and developments in the future and is prepared to initiate additional reporting efforts at the appropriate time.

3. Reporting by Both Upstream and Downstream Sources

Comment: Some commenters were concerned that requiring reporting by both fuel and industrial GHG suppliers (upstream sources) and direct emitters (downstream sources) results in double counting of GHG emissions and could lead to overestimation of emissions. Some commenters thought reporting by both upstream and downstream sources was duplicative, confusing, unnecessary, or burdensome and recommended the rule be revised to eliminate double reporting. Other commenters agreed with EPA's proposed selection of source categories to report and that reporting by upstream sources and downstream sources is needed to inform development of GHG policies and programs.

Response: This rule responds to a specific request from Congress to collect data on GHG emissions from both upstream production and downstream sources, as appropriate. The rule requires reporting by facilities that directly emit GHGs above the selected threshold as a result of combustion of fuel or industrial processes (downstream sources). The majority of these reporters are large facilities in the electricity generation and industrial sectors. The rule also requires upstream suppliers of fossil fuels and industrial GHGs to report the GHG emissions that could be emitted from combustion or use of the quantity of fuels or industrial gases supplied into the economy. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources. To cover these direct emissions would require reporting by hundreds or thousands of small facilities. To avoid this impact, the rule does not include all of those emitters but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels.

The data collected under this rule are consistent with the appropriations language and provide valuable information to EPA and stakeholders in the development of climate change policy and programs. Potential policies such as low carbon fuel standards can only be applied upstream, whereas end-use emission standards can only be applied downstream. Data from upstream and downstream sources would be necessary to formulate and assess the impacts of such potential policies. Eliminating reporting by either upstream sources or downstream sources would not satisfy EPA's data needs and policy objectives of this rule.

EPA acknowledges that there is inherent double reporting of emissions in a program that includes both upstream and downstream sources. However, as discussed in Sections I.D and IV.B of the preamble to the proposed rule (74 FR 16448, April 10, 2009) EPA does not intend to use emissions data collected by this rule as a replacement for the national emission estimates found in the annual Inventory of GHG emissions.

E. Summary of Comments and Responses on Thresholds

This section contains a brief summary of major comments and responses on EPA's approach and rationale for selection of reporting thresholds. *See* sections III.C through PP of this preamble for summaries of comments and responses on specific threshold analyses for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments 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, Selection of Reporting Thresholds, Greenhouse Gases, and De Minimis Provisions.''

Comment: Many commenters supported the proposed threshold of 25,000 metric tons of CO_2e per calendar year. These commenters generally agreed that the 25,000 metric ton threshold level achieves a reasonable balance between the percentage of national emissions covered and the number of reporters, resulting in a sufficiently comprehensive dataset while minimizing the impact on small facilities. Some also commented that this threshold is consistent with other existing GHG programs or likely future programs. Some commenters supported a 100,000 metric ton CO_2e threshold because they believe this level covers an appropriate percentage of national GHG emissions while easing the reporting burden on industry. Some commenters supported an emission threshold of 10,000 metric tons CO_2e to enable collection of emissions data for smaller sources. Some of these commenters also noted that a 10,000 metric ton CO_2e threshold is more appropriate in order to monitor leakage of emissions to smaller sources (since 25,000 metric tons of CO_2e is a likely threshold for future emissions reductions mandates). Some commenters suggested quantitative evaluation of intermediate threshold options in addition to the four evaluated by EPA (1,000; 10,000; 25,000; and 100,000); several of these suggested EPA analyze a threshold of 50,000 metric tons CO_2e to reduce the number of reporting facilities.

Response: As described in the preamble to the proposed rule (74 FR 16448, April 10, 2009), EPA considered four threshold levels, as well as capacity-based thresholds where appropriate, and we proposed a threshold of 25,000 metric tons of CO_2e for many source categories, and capacity-based or ''all in'' thresholds for other categories. Based on comments received, we reexamined the threshold analyses both in general and for each industry, taking into account additional data provided, and we considered whether there were reasons to develop different thresholds in specific industry sectors. The specific elements of these analyses are discussed in the relevant source category discussions in this preamble and the accompanying ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments'' volumes for each source category. At the general level, we also considered non-quantitative factors, such as consistency with State and other programs (the majority have established thresholds for GHG reporting at 25,000 metric tons or lower, such as 10,000 or 5,000 metric tons), and the need to select a threshold level that best satisfies the objective of the reporting rule to collect a national data set that is sufficiently comprehensive for use in analyzing a range of GHG policies and programs.

From these analyses, we concluded that a 25,000 metric ton threshold suited the needs of the reporting program by providing comprehensive coverage of emissions with a reasonable number of reporters, thereby creating the robust data set necessary for the quantitative analyses of the range of likely GHG policies, programs and regulations. Moreover, the 25,000 metric ton threshold covers similarly sized sources as covered by many current CAA programs (e.g., NSPS applies PM emissions limits to oil-fired and coal-fired units larger than 30 mmBtu per hour).[15] And, as mentioned previously, this level is consistent with (or higher than) the majority of other GHG reporting programs. Furthermore, having a uniform threshold [16] was an equitable approach because like facilities could be compared across sectors and no one industry would be disproportionately affected or subjected to a lower or higher threshold. A uniform threshold is also essential for evaluating potential policies and programs that could have a single emissions threshold across source categories (e.g., PSD), and simplifies the applicability determination for facilities that emit GHGs from more than one source category under the rule.

As discussed in Section IV.C of the preamble to the proposed rule (74 FR 16448, April 10, 2009), we considered four potential thresholds (the range of 1,000 to 100,000 metric tons of CO_2e) and from our analysis and the comments we concluded we had enough information to select an appropriate threshold for the final rule and that detailed quantitative analyses of additional intermediate thresholds would not change EPA's decision. For example, in reviewing our threshold analyses, we determined that the intermediate options between 25,000 and 100,000 metric tons would not provide an alternative threshold that substantially reduced the number of the reporters relative to other options considered or substantially improved the cost effectiveness. (*See* ''Review of Threshold Analyses'' memorandum in docket EPA–HQ–OAR–2008–0508.) Based on our proposal analysis on the data available, we saw that the majority of the affected facilities or suppliers had emissions either considerably above or below 25,000 metric tons CO_2e per year. (As previously explained, supplier GHG quantities represent the emissions that could be released when the products they supply are combusted or used.) The selected threshold took into account our finding that while a threshold other than 25,000 metric tons of CO_2e might appear to achieve an appropriate balance between the number of facilities and emissions covered for a limited number of source categories, there are several additional reasons for selecting the threshold of 25,000 metric tons of CO_2e per year.

The lower threshold alternatives that we considered were 1,000 metric tons of CO_2e per year, and 10,000 metric tons of CO_2e per year. At proposal, we explained that we did not select either of these thresholds because although both broaden national emissions coverage, they do so by disproportionately increasing the number of affected facilities. With the data available at proposal and from the comment period, we remain convinced that the 1,000 metric ton CO_2e/year threshold would increase the number of reporters by an order of magnitude, thus changing the focus of the program from large to small emitters and imposing reporting costs on tens of thousands of small businesses that in total would amount to less than 10 percent of national GHG emissions. Our analysis indicates that a 10,000 metric ton CO_2e/yr threshold would approximately double the number of reporters, but would only increase national emissions coverage by one percent. (See the Regulatory Impacts Analysis for the final rule for the estimated number of facilities and GHG emissions covered by the alternative thresholds examined.) While some proposals (e.g., WCI and H.R. 2454, American Clean Energy and Security Act) contain a 10,000 metric ton threshold for reporting, EPA concluded for policy evaluation purposes, the 25,000 metric ton threshold more effectively targets large industrial emitters and suppliers, covers approximately 85 percent of U.S. emissions, and minimizes the burden on smaller facilities.

We also reviewed the 100,000 metric tons of CO_2e per year as an alternative threshold but concluded that it fails to satisfy key objectives. It excludes a number of emitters in certain source categories such that the emissions data would not adequately cover key sectors of the economy. At 100,000 metric tons CO_2e per year, reporting for some large industry sectors would be rather significantly fragmented, resulting in an incomplete understanding of direct emissions from that sector. We concluded that this threshold would not sufficiently cover the types of facilities that are typically regulated under the CAA and would be inadequate for the intended use of analyzing potential policies and developing future CAA programs.

Based on our review, EPA has determined that the selected 25,000 metric ton CO_2e threshold will cover many of the types of facilities and suppliers typically regulated under the CAA, while appropriately balancing

[15] As explained in section II.A of this preamble, facilities that only have stationary combustion units as their only source of emissions and have units with an aggregate maximum heat input of less than 30 mmbtu are not included in this rule.

[16] Although the thresholds were expressed in different ways (e.g., ''all-in'', annual emissions) most corresponded to, or were consistent with, an annual facility-wide emission level of 25,000 metric tons of CO_2e.

emission coverage and burden. At this threshold, EPA will be able to evaluate the effects of a number of options and policies that could address GHG emissions without placing an undue burden on a large number of smaller facilities and sources. In addition, this threshold level is largely consistent with many of the existing GHG reporting programs and different legislative proposals in Congress. Furthermore, many industry stakeholders that EPA met with and the majority of public commenters, representing a wide variety of stakeholders, expressed support for a 25,000 metric ton CO_2e threshold, agreeing with the Agency's assessment of coverage.

F. Summary of Comments and Responses on Level of Reporting

This section contains a brief summary of major comments and responses on the level of reporting. A large number of comments 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, Selection of Source Categories to Report and Level of Reporting.''

Comment: Many commenters supported facility-level reporting rather than corporate-level reporting. The reasons they gave included: Facility-level reporting is consistent with most air rules and permitting programs, environmental managers are used to facility-level reporting, facility-level data would be needed to implement likely future regulatory programs such as a cap and trade program, this approach is simpler to implement and minimizes administrative burden, a facility's corporate status can change during the year, and tying data to physical sources makes emissions easier to track and monitor over time. On the other hand, several commenters favored corporate-level reporting. The reasons they gave included: The effect of GHG emissions is global, therefore the location where the GHGs are emitted is not important; various other GHG programs require corporate-level reporting and have mechanisms for handling ownership changes; the overall carbon footprint of a corporation is important; a company's entire emissions should be reported, not just those facilities that are above a threshold; and facility-level data are more likely to be CBI.

Response: In response to comments, EPA reviewed our initial views outlined in Sections IV.D and V of the proposal preamble (74 FR 16448, April 10, 2009) in light of our data needs under the CAA, our interpretation of the Congressional request, and the feedback received. Based on these considerations, we determined that the final rule will retain the same reporting level as the proposed rule. Facility-level reporting is required, with the exception of some supplier source categories (e.g., importers of fuels or industrial GHGs or manufacturers of motor vehicles and engines). If a facility is covered by the rule, the reporter must report the facility's GHG emissions from all source categories for which the rule contains GHG emission methods. The total emissions for the facility are reported, as well as emissions broken out by source category within the facility. Subparts for some source categories specify further breakout of emissions by process line or unit.

We retained this approach because the purpose of this rule is to collect data from suppliers and from facilities with direct GHG emissions above selected thresholds for use in analyzing, developing, and implementing potential future CAA GHG policies and programs. Facility-level data are needed to support analyses of some types of potential GHG reduction programs, such as NSPS. The data collected from facility-level reporting under this rule will improve our ability to formulate a set of climate change policy options and to assess which facilities and industries would be affected by the options and how they would be affected. (Note, we expect that similarly, facility-level data will also be useful to States, the public, and other stakeholders to formulate State and regional programs and track emission trends over time.) Reporting by individual facilities is also consistent with most existing air regulatory such as ARP, NSPS and national emission standards for hazardous air pollutants (NESHAP), and permitting programs. Many facility environmental managers are already experienced with facility-level emissions reporting under such programs and can likewise submit reports under the mandatory GHG reporting rule.

Corporate-level reporting was not selected because corporate reporting without facility-specific details would not provide sufficient data to assess many potential CAA GHG policies and programs. EPA understands that some corporate-level GHG reporting programs have mechanisms to establish reporting responsibilities under complex and changing ownership situations, but we find corporate-level reporting overly complex for this rulemaking given that facility level data are needed, and it is simpler to place reporting responsibility directly on individual facilities. We note that while EPA requires facility-level reporting, it is up to the facility owners and operators to select the designated representative who will submit the report for a facility, and reporters can also establish any internal corporate review processes they deem appropriate.

While EPA agrees with the commenters who indicated that information on corporate carbon footprints is useful for various purposes, collection of such information is outside the scope of this rulemaking. With that said, 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. In any event, we expect that the facility-level data collected under this rule will be useful for programs that request or require corporate reporting. But, as explained in Sections I.D and I.E of this preamble, this reporting rule is one action to respond to a specific request from Congress. Various other Federal and State programs are collecting and will continue to collect corporate-level data on direct and indirect emissions, energy efficiency, and other data as part of a broad array of climate change initiatives.

For the response to the commenters' concern about CBI, see Section II.R of this preamble.

G. Summary of Comments and Responses on Initial Reporting Year and Best Available Monitoring Methods

This section contains a brief summary of major comments and responses on the initial reporting year. A large number of comments 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, Initial Year of Reporting, Duration of the Reporting Program, and Provisions to Cease Reporting.''

Comment: The proposed rule included reporting of calendar year 2010 emissions in March 2011, which would require reporters to collect data starting on January 1, 2010. The preamble to the proposed rule also discussed options of allowing reporting of best available data for 2010, or delaying reporting by one year (64 FR 16471, April 10, 2009). Many industries with source categories covered by the proposed rule commented that a data collection start date of January 1, 2010, does not provide sufficient time to review the final rule, purchase and install required monitoring equipment, train staff, and develop internal electronic data management and recordkeeping systems needed to comply with the rule. Many indicated that they do not currently have all the meters and monitoring equipment required by the rule. Most of these commenters strongly stated that calendar year 2011 should be the first reporting year. Many of them also stated that if EPA decides data collection must begin in 2010, a best available data approach should be allowed for calculating and reporting 2010 emissions.

Conversely, Congressional inquiries and a large number of public commenters including States, NGOs, and the general public, emphasized that data collection must start in 2010 because time is of the essence for developing and implementing GHG policies and programs. These commenters urged EPA to require reporting of calendar year 2010 GHG emissions and not to delay data collection until calendar year 2011.

Some of the commenters made suggestions about the types of data and methods that could be allowed if EPA chose to use a best available data approach for 2010.

Response: EPA carefully reviewed input from all commenters with the goal of balancing the urgent need for data against the legitimate concerns raised regarding timing. As a result, we have revised the approach for the final rule. The final rule requires data collection for calendar year 2010, but has been changed since proposal to allow use of best available monitoring methods for the first quarter of 2010.

Schedule. EPA decided to require reporting of calendar year 2010 emissions because the data are crucial to the timely development of future GHG policy and regulatory programs. In the Appropriation Act, Congress requested EPA to develop this reporting program on an expedited schedule, and Congressional inquiries along with public comments reinforce that data collection for calendar year 2010 is a priority. Delaying data collection until calendar year 2011 would mean the data would not be received until 2012, which would likely be too late for many ongoing GHG policy and program development needs.

However, EPA understands that because the final rule is not being promulgated until fall of 2009, facilities that do not already have the monitoring systems required by the rule in place might not have time to install and begin operating them by January 1, 2010. Under the schedule in the Appropriations Act, the final rule would have been signed at the end of June 2009, which would have allowed approximately six months to prepare for data collection in January 2010. Given the delay in promulgating the rule, there is less time between signature of the rule and a January 1, 2010 start date. In light of this fact, and the industry comments indicating that facilities do not currently have all of the required monitoring systems, EPA has decided to provide flexibility by establishing a best available monitoring methods option for the first quarter of calendar year 2010. This approach will provide time comparable to what would have occurred had EPA met the schedule in the Congressional request. We will post the rule on EPA's Web site soon after signature, allowing reporters to see the final requirements and begin compliance planning even before the rule is published in the **Federal Register**.

For the time period of January 1 through March 31, 2010, the rule allows use of best available monitoring methods for parameters that cannot reasonably be measured according to the monitoring and QA/QC requirements of the relevant subpart. Starting no later than April 1, 2010, the reporter must begin following all applicable monitoring and QA/QC requirements of this part, unless they submit an extension request showing that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by the specified date and EPA approves the request. EPA may approve such requests for a set time period, but will not approve the use of best available methods beyond December 31, 2010. See the paragraph heading ''Extension Request Process'' near the end of this response for further details.

EPA has concluded that the time period allowed under this schedule (including the provision for facility-specific requests) will allow facilities that do not currently have the required monitoring systems sufficient time to begin implementing the monitoring methods required by the rule. In general, the required monitors, such as flow meters, are widely available and are not time consuming to install. By allowing the additional time, many facilities may also be able to install the equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions.

Definition of Best Available Monitoring Methods. In determining methods that would be allowed under a best available monitoring methods approach, EPA considered the goal of collecting consistent data to provide information of sufficient quality to inform policy and program development, while recognizing that not all facilities may be able to implement the full monitoring methods required by the rule by January 2010. We reviewed the public comments as well as the California Air Resources Board (CARB) mandatory reporting rule, and we considered options falling between full flexibility to use any method and the full requirements of EPA's mandatory reporting rule.

The least stringent approach would be to allow facilities to calculate GHG emissions using any data, methods, calculation procedures, or emission factors they choose during the best available monitoring period and submit minimal supporting data. This approach would provide maximum flexibility to industry, but EPA did not select this approach because the usefulness of the collected data would be questionable given that it would be obtained using inconsistent methods and it could not be verified with sufficient confidence. Instead, EPA developed a hybrid approach that falls between full flexibility and implementation of full monitoring requirements in January 2010. Under the final rule, during January 1, 2010, through March 31, 2010, reporters may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) if that parameter cannot reasonably be measured following the monitoring and QA/QC requirements of a relevant subpart. The reporter must use the calculation procedures 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. Best available monitoring methods include the following:

- Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart.
- Supplier data.
- Engineering calculations.
- Other company data.

Reporters must submit an annual GHG report for 2010. This calendar year 2010 report (submitted March 31, 2011) includes the same information as in subsequent years, but also requires brief descriptions of each best available monitoring method used, the parameter measured using that method, and the time period during which the method was used.

EPA selected this approach because it is responsive to commenters' concerns that monitoring equipment cannot be installed by January 1, 2010, while also ensuring timely submission of more consistent and verifiable data than the alternatives. We have concluded that the data will be more consistent because all reporters will use the same basic emissions calculation equations that are in the rule, with best available inputs, rather than the wide range of calculation methods that would likely be used under a full flexibility approach. Furthermore, the selected approach requires reporting of sufficient information for EPA to verify the emissions data. We have therefore determined that this approach for collection and reporting of the calendar year 2010 data will fulfill the objectives of this reporting rule.

It should also be noted that, like the proposed rule, the final rule allows facilities that must report only emissions from general stationary fuel combustion equipment (and do not have other covered source categories) to determine calendar year 2010 emissions using any of the methods (tiers) in 40 CFR part 98, subpart C, and submit an abbreviated GHG report. Full reporting starts with calendar year 2011. This allows such facilities, which are less likely to have experience with emissions monitoring and reporting, an extra year to begin full reporting using all the procedures required by the rule.

Extension Request Process. We expect that the vast majority of facilities will begin complying with the full monitoring requirements of the rule no later than April 1, 2010, and will not require or be granted an extension. However, EPA is providing facilities with specific circumstances an opportunity to request an extension in the use of best available monitoring methods. EPA will review extension requests to determine whether they should be approved. We envision that extensions will apply primarily to situations when needed monitoring instrumentation could not be obtained within the timeframe despite good faith efforts by the facility, or when installation of monitoring instrumentation would require a process unit shutdown that could not feasibly be scheduled prior to April 1, 2010.

Timing. Reporters must submit extension requests to EPA no later than 30 days after the effective data of the GHG reporting rule. EPA intends to review each submitted request and may approve or disapprove the requests. EPA may approve the request for a specified time period, but will not approve the use of best available methods beyond December 31, 2010. If EPA disapproves an extension request, then the reporter is required to implement the full monitoring methods required by the rule by April 1, 2010.

Content of Request. Requests must contain the following information:

- A list of specific monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.
- Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.
- A detailed description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.
- 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.
- 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 possible to isolate the equipment, piping, or line and install the monitoring instrument without a full process unit shutdown. Also 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 rule and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.
- 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.

Approval Criteria. EPA will approve a request if it contains all of the information required by the rule and if it demonstrates 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.

For example, EPA is likely to approve a request for an extension if the documentation provided by the reporter shows that they ordered monitoring equipment in a timely manner, attempted to find a supplier who could deliver it in time, and could not control the fact that the equipment was not received for installation prior to April 1, 2010.

If a reporter requests an extension because equipment cannot be installed without a process unit shutdown, EPA is likely to approve such a request if the documentation clearly demonstrates why it is not feasible to install the equipment without a process unit shutdown, shows there is not a planned shutdown (and has not been a shutdown) prior to April 1, 2010, during which the monitoring instrument could be installed. There are many locations where monitors can be installed without a process unit shutdown, because there is often some redundancy in process or combustion equipment or in the piping that conveys fuels, raw materials and products. For example, many facilities have multiple combustion units and fuel feed lines such that when one combustion unit is not operating they can obtain the needed steam, heat, or emissions destruction by using other combustion devices. Some facilities have multiple process lines that can operate independently, so one line can be temporarily shut down to install monitors while the facility continues to make the same product in other process lines to maintain production goals. If a monitor needs to be installed in a section of piping or ductwork, it can be possible in some cases to isolate a line without shutting down the process unit (depending on the process configuration, mode of operation, storage capacity, etc.). If the line or equipment location where a monitor needs to be installed can be temporarily isolated and the monitor can be installed without a full process unit shutdown, it is less likely EPA will approve an extension request.

While there might be other unique facility-specific situations for which an extension might be granted, EPA expects few of these. There have been several changes to the rule since proposal that would reduce the need for extensions. For example, fewer source categories are included in the final rule; changes have been made to the monitoring requirements of some rule subparts to allow more flexibility in monitoring methods; and provisions have been added to the general stationary fuel combustion, petroleum refineries, and petrochemical productions subparts allowing facilities additional time to perform some monitor calibrations. These changes address many of the specific situations about which commenters raised concerns.

It is highly unlikely we would approve extension requests for parameters that are measured by periodic sampling and analyses. Facilities should be able to make arrangements to collect periodic samples and send them off-site for analyses (if they don't have on-site analytical capabilities) without the need for an extension. Similarly, extensions for design of electronic recordkeeping systems seem unnecessary. Many facilities already have electronic recordkeeping systems that can be altered to keep the records needed for this rule. Furthermore, reporters can keep the specified records in any type of hard copy or electronic format they choose, as long as it is in a form suitable for expeditious inspection and review.

H. Summary of Comments and Responses on Frequency of Reporting and Provisions To Cease Reporting

This section contains a brief summary of major comments and responses on the frequency of reporting and on whether reporters should be allowed to stop submitting annual reports if emissions are reduced below a threshold level. A large number of comments 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, Initial Year of Reporting, Duration of the Reporting Program, and Provisions to Cease Reporting'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Applicability and Reporting Schedule.''

1. Provisions To Cease Reporting if Emissions Decrease

Comment: The majority of public commenters favored annual reporting as opposed to more or less frequent reporting. Many commenters, especially industrial facilities required to report under the rule, objected to the ''once in always in'' reporting approach in the proposed rule and requested a mechanism to stop reporting if emissions fall below the 25,000 metric tons CO_2e per year annual threshold. Others suggested a level different from 25,000 metric tons CO_2e per year to cease reporting. Some commented that the lack of such a mechanism is a disincentive to reduce facility emissions. Conversely, other commenters supported the proposed once in always in approach in order to create a consistent, long term data set covering the same population of facilities over time that could be used to track trends and understand factors that influence emission levels.

Response: After reviewing the comments, EPA has not changed the frequency of reporting since the proposed rule. Affected facilities and suppliers must submit annual GHG reports. Facilities with ARP units that report CO_2 emissions data to EPA on a quarterly basis would continue to submit quarterly reports as required by 40 CFR part 75, in addition to providing the annual GHG reports. We have determined that annual reporting is sufficient for policy and regulatory development. It is also consistent with other existing mandatory and voluntary GHG reporting programs at the State and Federal levels (e.g., The Climate Registry (TCR), several individual State mandatory GHG reporting rules, EPA voluntary partnership programs, the DOE voluntary GHG registry).

In response to comments on ''once in, always in,'' however, EPA has added provisions to allow facilities and suppliers to stop submitting annual reports under certain conditions. These provisions apply to facilities and suppliers regardless of their applicability threshold as it is based on the annual report.

- Under the first provision, if any facility's annual GHG reports demonstrate emissions of less than 25,000 metric tons of CO_2e per year for five consecutive years, they can cease submitting annual reports. Similarly, if any supplier's annual reports demonstrate that the products supplied equate to less than 25,000 metric tons of CO_2e per year for five consecutive years, they can cease submitting annual reports.
- Under the second provision, if any facility's or supplier's annual GHG reports demonstrate emissions of less than 15,000 metric tons CO_2e per year for three consecutive years, they can cease submitting annual reports.

In either case, before they can stop reporting, the facility or supplier must submit a notification to EPA that announces the cessation of reporting and explains the reasons for the reduction in emissions so EPA can understand the reason for the decrease in emissions to help aid in evaluating emission reduction options across the industry.

If emissions subsequently increase to 25,000 metric tons of CO_2e or more in any calendar year, the facility or supplier must again begin annual reporting. Importantly, although a source may not know its emissions (or quantities supplied) exceeded the reporting threshold until later in the year, the requirements of the rule apply as of January 1, unless the increase is a result of a physical or operational change covered by 40 CFR 98.3(b). Thus sources close to the threshold should consider monitoring their emissions according to requirements of 40 CFR part 98 if they determine there is a chance they will meet or exceed the threshold. EPA is developing tools and guidance to assist facilities and suppliers in assessing whether the requirements of the rule apply to them.

EPA concluded that adding the provisions to allow cessation of reporting balances the need for a complete dataset with the burden of continued annual reporting by facilities where there has been a change that has consistently reduced emissions (or supplier quantities) below 25,000 metric tons CO_2e. This approach rewards actions taken to reduce emissions and reduces the reporting burden. It is consistent with other reporting programs, such as the CARB mandatory reporting rule and the WCI program, both of which have mechanisms to allow facilities to cease reporting if their emissions are below a specified threshold for multiple consecutive years.

For the first provision, EPA selected 25,000 metric tons CO_2e per year because it is the same as the general applicability threshold for this rule.[17] We selected a 5-year period, instead of a shorter time frame, because it allows reporters that consistently report less than 25,000 metric tons CO_2e to stop reporting, but avoids the situation where a facility or supplier near this level would be constantly moving in and out of the reporting program due to small variations from one year to the next. Because this reporting rule is based on actual rather than potential emissions, such a situation would make tracking of facilities and analyses of trends difficult.

The second provision (cease reporting if emissions were below 15,000 metric tons for three consecutive years) was added to reduce the duration of reporting for facilities and suppliers that reduce emissions to well below 25,000 metric tons. In such cases, a 5-year period is longer than necessary to

[17] Applicability thresholds for different source categories are expressed in different ways (e.g., actual emissions, production capacity, ''all-in''), but most correspond to a facility-wide emission level of 25,000 metric tons per year. The provision to cease reporting applies to reporters regardless of the specific applicability threshold that triggered reporting for their facility or supply operation.

demonstrate that annual emissions will remain below 25,000 metric tons per year. If emissions are less than 15,000 metric tons for three consecutive years, it is unlikely that annual variation in emissions would cause the facility or supplier to exceed the threshold of 25,000 metric tons per year. The shorter time period provides an incentive for facilities that significantly reduce their GHG emissions.

2. Provisions To Cease Reporting Due to Closures

Comment: Several commenters suggested that EPA add a provision to allow closed facilities, or facilities or suppliers that stop operating their GHG-emitting processes, to cease annual reporting.

Response: In response to comments, EPA has added a mechanism to allow facilities or suppliers that close all of their GHG-emitting processes or operations covered by the rule to cease annual reporting. The reporter must submit an annual report covering the calendar year during which the closure occurs. The reporter must also notify EPA that they intend to cease reporting and must certify that all GHG-emitting processes and operations for which there are methods in the rule have been closed. EPA agrees that it does not make sense for closed facilities or facilities that close all of their GHG-emitting processes to continue reporting indefinitely or for the 5-year period needed to demonstrate that emissions are less than 25,000 metric tons CO_2e per year (or the 3-year period needed to demonstrate emissions are less than 15,000 metric tons CO_2e per year). However, notification is required so that we can track facilities and understand why facilities stop reporting. If a facility or supplier that was once subject to the reporting rule and ceased reporting under this provision restarts any of the GHG-emitting processes or operations formerly reported, then they must resume annual reporting regardless of whether they exceed the thresholds in 40 CFR 98.2(a) when they restart. This provision is important so that EPA can consistently track emissions from facilities covered by the rule. If after the restart, annual reports show emissions of less than 25,000 metric tons CO_2e per year for five consecutive calendar years or less than 15,000 metric tons CO_2e per year for three consecutive years, then the facility could be exempt under the separate mechanism discussed in Section II.H.1 of this preamble.

It is important to note that the provision to stop reporting is not intended to apply to seasonal or longer temporary cessation of operation. The mechanism is intended for long-term closure situations. It should also be noted that in order to use this provision to cease reporting, a facility or supplier must close *all* of their processes and operations that are required to report emissions. For example, consider a facility that is required to report process emissions from one or more source categories covered by 40 CFR part 98 and general stationary fuel combustion source emissions. If the facility closes some of the process units subject to the rule but continues to operate other process units covered by the rule or continues to operate stationary fuel combustion sources, then they must continue to submit annual reports until the required annual GHG reports demonstrate emissions of less than 25,000 metric tons of CO_2e per year for five consecutive years (or less than 15,000 metric tons of CO_2e per year for three consecutive years) and the facility qualifies for the separate provisions to stop reporting discussed in Section II.H.1 of this preamble.

I. Summary of Comments and Responses on General Content of the Annual GHG Report

This section contains a brief summary of major comments and responses on the emissions information to be reported under the general provisions (40 CFR part 98, subpart A). See sections III.C through PP of this preamble for summaries of comments and responses on specific reporting requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments on emission information to report under the general provisions 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 A: Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and Monitoring Plan.''

Comment: EPA received a variety of comments on the general content of the annual GHG reports. Some commenters objected to the level of detail required in the annual GHG reports. Some suggested reporting only facility-level emissions and keeping as records more detailed emissions breakouts (e.g., by source category, process line, or unit) and activity data used to calculate emissions. Other commenters supported the proposed general reporting requirements.

Response: After reviewing the comments, we have not made any major changes in the general content of the annual GHG reports since proposal. The final rule requires facilities to report emissions from all source categories at the facility for which methods are defined in the rule. The General Provisions (40 CFR part 98, subpart A) require facilities to report total annual GHG emissions in metric tons CO_2e and to separately present annual mass emissions of each individual GHG emitted from each source category at the facility. Reporting of CO_2e allows a comparison of total GHG emissions across facilities in varying categories which emit different GHGs. Knowledge of both individual gases emitted and total CO_2e emissions maintains transparency, is valuable for future policy and regulatory development, and will help EPA quantify the relative contribution of each gas to a source category's emissions and maintain transparency.

Individual rule subparts for each source category, rather than the General Provisions, identify the specific data elements to be reported for that source category. Comments received on the need for specific data elements are described and responded to in Section III of this preamble and in relevant source category volumes of the ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments''. Where appropriate, the final rule has been modified based on those comments. In general, reporting of such data is required primarily to enable emissions verification and ensure the consistency and accuracy of data collected under this rule. The information is also needed to support analyses of GHG emissions for future CAA policy and program development. Besides total facility emissions, it benefits policy makers to understand: (1) The specific sources of emissions and the amounts emitted by each unit/process to effectively interpret the data, and (2) the effect of different processes, fuels, and feedstocks on emissions. Many of these data are already routinely monitored and recorded by facilities for business reasons. Further discussion of the selection of general reporting requirements is contained in Section IV.G of the proposal preamble (74 FR 16472, April 10, 2009). Other responses to comments on the reporting requirements in 40 CFR Part 98, Subpart A, and discussion of some clarifications made to the rule, are contained in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Applicability and Reporting Schedule'', ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart

A: Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and Monitoring Plan'', and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Definitions, Incorporation by Reference, and Other Subpart A Comments''.

J. Summary of Comments and Responses on Submittal Date and Making Corrections to Annual Reports

1. Submittal Date for Annual Report

Comment: Several commenters requested that EPA change the annual submittal date for GHG reports from March 31 to a later date, such as April 30 or June 30. Several commenters stated that March 31 does not provide adequate time for data collection, aggregation and disaggregation, GHG calculations, QA, management review, and certification, and explained that this is a complex process for large industrial sites that have many individual GHG emission sources. Some of these commenters indicated that unexpected issues can arise during GHG emissions calculations and QA that take time to resolve. Some of these commenters suggested a date of June 30 to align this mandatory reporting rule with the submittal dates for other reporting programs such as California Climate Action Registry (CCAR), TCR, Climate Leaders, and Toxic Release Inventory (TRI). Some commented that the same personnel who will prepare the GHG reports are also involved in preparing other EPA mandated reports and that completing multiple reporting activities in the first quarter is a large workload. Other commenters favored the March 31 reporting date so that the data could be disseminated and available for use by policy makers, EPA, States, and the public in a timely fashion.

Response: After reviewing and addressing both general comments and comments received on this issue for specific source categories, and considering the need to balance prompt reporting with the burden on reporters, EPA has determined that the reporting deadline of March 31 allows a sufficient amount of time for compiling, reviewing, certifying, and submitting annual GHG reports. The March deadline will ensure timely collection of the data necessary to inform decisions regarding future GHG policy and program development. Since the data needed to calculate emissions and prepare the report must be collected on an ongoing basis throughout the year, reporters can begin to compile the data for the report and initiate QA activities during the year as the data are collected. Reporters would then only have to compile the most recently collected information, complete the final calculations, and review and certify the annual report after the reporting period has ended. Because the reports required by the rule rely on well-defined calculation methodologies, EPA determined that three months is a sufficient amount of time to complete the report. Moreover, as discussed in Section III of this preamble for the specific subparts, we have made several changes to reporting requirements that will ease burden and further facilitate reporting by March 31. In addition, EPA intends to provide outreach and training on rule requirements and an electronic reporting system that will help expedite report submission.

The March 31 reporting deadline is also consistent with the reporting deadline implemented in 2005 for reporting GHG emissions under the EU Emissions Trading System and is longer than the deadlines allowed for reporting under many other CAA programs. For example, many NESHAPs and NSPSs, including those for large complex industrial facilities such as chemical plants and refineries, require reports of excess emissions and monitoring system performance to be submitted within 30 calendar days of the end of each compliance period. The ARP and Regional Greenhouse Gas Initiative (RGGI) programs, which are established emission cap and trade programs that rely on the same types of data many sources will have to submit under the GHG reporting rule, require facilities to submit their quarterly emissions reports within 30 days of the end of each quarter.

2. Making Corrections to Annual Reports

Comment: Several commenters representing multiple stakeholders suggested the rule should include provisions to submit revised annual reports. Many commented that even with good-faith efforts to follow all the monitoring and reporting requirements, there will likely be unintentional errors that are not discovered by the reporter or by EPA until after an annual report is submitted. Some commenters added that given the stringency of the self-certification provisions and potential penalties involved, reporters need a way to submit corrected data, and some provided examples of other reporting rules that include provisions to submit revised reports.

Response: EPA has addressed this comment in the final rule. We have added a provision in 40 CFR 98.3 that requires the reporters to submit a revised GHG report within 45 days of discovering or being notified by EPA of errors in an annual GHG report. The revised report must correct all identified errors. We agree that it is important for facilities to correct errors, regardless of whether they are discovered by the reporter or by EPA. In order to ensure accurate data for future GHG policies and programs, known errors should be corrected. Furthermore, adding a requirement to submit corrected reports is consistent with other EPA reporting programs, such as ARP and TRI, as well as State and other GHG programs. EPA intends to review the annual GHG reports submitted under this rule by performing electronic data QA checks and a range of other emission verification activities. When we find reporting errors (as we have in ARP and other reporting programs), we will notify reporters of errors and require them to submit revised reports. The time period of 45 days was selected to allow reporters time to retrieve any needed data, perform revised calculations, and resubmit the report. Because data for the calendar year covered by the report has already been collected and must be retained according to the rule, it should be readily available for any reanalyses needed to correct a reporting error. Given that facilities are allowed three months from the end of a reporting period to submit the annual report, revising a report to address a known error would logically require less time and EPA concluded that 45 days is sufficient.

K. Summary of Comments and Responses on De Minimis Reporting

Comment: Some commenters suggested that *de minimis* cutoffs or simplified methods for *de minimis* sources should be provided to be consistent with other programs, such as the California mandatory GHG reporting rule. The commenters argued that it makes sense to focus effort on the significant emissions sources at a facility, rather than spending a lot of effort to precisely calculate emissions from sources that are a small percent of a facility's total emissions.

Response: EPA considered public comments on *de minimis* reporting, both general comments and those received on individual source categories, in addition to the analyses of *de minimis* provisions we conducted at proposal of the rule. Based on these considerations, we concluded that *de minimis* provisions are not necessary for this rule.

As discussed in the preamble to the proposal (74 FR 16448, April 10, 2009), many existing reporting programs require corporate level reporting of all emissions, including emissions from numerous remote facilities and small onsite equipment (e.g., lawn mowers). Other reporting programs require reporting at the facility level but require reporting of emissions from all types of emission sources.[18] These reporting programs recognize that it may not be possible or efficient to specify the reporting methods for every source that must be reported and include *de minimis* provisions to reduce the reporting burden. The *de minimis* provisions included in these programs either allow the reporter to exclude a portion of their emissions (e.g., the DOE 1605(b) voluntary reporting program allows up to three percent of facility-level emissions to be excluded) or allow simplified calculation methods for small sources.

Since reporters must determine the *de minimis* emissions even when reporting is not required, the trend for both mandatory and voluntary reporting programs is to require reporting of all emissions but allow simplified calculation methods for small sources of emissions. Hence, the *de minimis* provisions included in many existing reporting programs are designed to avoid potentially unreasonable reporting burdens. For example, TCR allows reporters to use simplified calculation methods of their own design for calculating up to five percent of their emissions. Some programs recognize that a small percentage of emissions may still represent a large mass of emissions. For this reason, some existing reporting programs include a cap on the mass of *de minimis* emissions. For example, both the California mandatory reporting rule and EU Emissions Trading System cap *de minimis* emissions at 20,000 metric tons CO_2e/year cap. For additional information on the treatment of *de minimis* in existing GHG reporting programs, please refer to the ''Reporting Methods for Small Emission Points (De Minimis Reporting)'' (EPA–HQ–OAR–2008–0508–0048).

In contrast to such existing programs, this rule already avoids burdensome reporting requirements for smaller emissions sources in two ways. First, the rule excludes small facilities through the application of the 25,000 metric tons of CO_2e threshold. As described earlier in this preamble, that threshold appropriately balances the number and size of reporter with the coverage of emissions. The source categories included in the rule are typically for larger sources of emissions. Second, reporters must report only the emissions from sources for which calculation methods are provided in the rule. Calculation methods are generally not included for smaller sources of emissions (e.g., coal piles on industrial sites). In some cases, where a source category includes relatively small sources, the rule provides simplified emissions calculation methods for those sources. For example, reporters may use a default emission factor and heat rate to calculate emissions from small stationary combustion units, rather than the fuel measurements required for larger stationary combustion units. Given that this rule has taken steps to avoid burdensome calculations, we have concluded that *de minimis* reporting cutoffs are not necessary.

Furthermore, *de minimis* cutoffs would compromise the quality of the data collected. The goal of this rule is to collect accurate and consistent data of sufficient quality to inform future CAA policy and regulatory decisions. Allowing sources to report up to 20,000 metric tons CO_2e emissions annually using their own simplified calculation methods (as allowed under some programs) would impact the usefulness of the data. The reported emissions would not be comparable across a given industry because the calculation methods, accuracy and reliability of a portion of the reported emissions would vary substantially from one reporter to another.

In response to comments, we have made several changes to this rule that further reduce any need for a *de minimis* reporting provision. As discussed in Section III of this preamble for individual source categories, we have revised monitoring and reporting requirements to allow simpler GHG calculation methods for many combustion units and other source categories. These changes reduce the reporting burden for various types of small emission sources. Also, as noted earlier in Section II.D of this preamble, there are a number of source categories that are not being finalized at this time. A few of them (e.g., industrial landfills and wastewater) represent the type of emission sources that commenters referenced as *de minimis* at some facilities. EPA is taking some additional time with these source categories, which affects commenters in two ways: (1) Until EPA promulgates a final rule for these source categories, these emissions would not be included in a facility's annual report and (2) EPA can further consider the comments and evaluate our options with respect to the methods for these source categories to ensure the methods adequately address our need for high quality data as well as recognize the commenters' requests for additional flexibility for smaller sources.

L. Summary of Comments and Responses on General Monitoring Approach

This section contains a brief summary of major comments and responses on general monitoring requirements. See sections III.C through PP of this preamble for summaries of comments and responses on specific monitoring requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments were received on general monitoring requirements covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, General Montoring Approach, the Need for Detailed Reporting, and Other General Rationale Comments.''

Comment: Many commenters favored the general monitoring approach contained in the proposed rule, which is a combination of direct emissions measurement and facility-specific calculations. These commenters agreed that the selected approach results in high quality data and strikes a reasonable balance between data accuracy and cost. Other commenters believed that the approach contained in the proposed rule is overly stringent and costly. They contended that since the data are not being used to demonstrate compliance with a cap and trade program or other regulation with emission limits or emissions reduction requirements, a lower level of accuracy is acceptable, simpler monitoring approaches should be allowed, and/or facilities should have flexibility to choose monitoring methods. Some commenters requested clarification on whether there were accuracy requirements or performance standards for flow monitoring equipment, outside of the accuracy requirements already required for CEMS. Some commenters requested clarification on whether upgrades to CEMS were needed under various circumstances. Some requested additional time for upgrading CEMS or installing and calibrating other equipment such as flow meters.

Response: After reviewing the comments in light of the analysis

[18] For additional information about these programs please see overview of existing programs (EPA–HQ–OAR–2008–0508–0052) and the *de minimis* memo (EPA–HQ–OAR–2008–0508–0048).

presented in Section IV.H of the preamble to the proposed rule (74 FR 16474, April 10, 2009), EPA decided not to change the general monitoring approach from the proposal. In general, the rule requires direct measurement of emissions from certain units that already are required to collect and report data using CEMS under other programs (e.g., ARP, NSPS, NESHAP, State Implementation Plans (SIPs)). In some cases, this may require upgrading existing CEMS that currently monitor criteria pollutants to also monitor CO_2 or add a volumetric flow meter. For facilities with units that do not have CEMS installed, reporters have the choice to either install and operate CEMS to directly measure emissions or to use facility-specific GHG calculation methods. The measurement and calculation methods for each source category are specified in each subpart. As policies and programs evolve and/or particular calculation or monitoring equipment improves EPA will evaluate whether or not to update the methodologies in this rule.

The data collected by the rule are expected to be used in analyzing and developing a range of potential CAA GHG policies and programs. A consistent and accurate data set is crucial to serve this intended purpose. Therefore, the selected monitoring approach that combines direct measurement and facility-specific calculations is warranted even though the rule does not contain any emissions limits or emissions reduction requirements. EPA remains convinced that this approach strikes an appropriate balance between data accuracy and cost. It makes use of existing data and methodologies to the extent feasible, and avoids the cost of installing and operating CEMS at numerous facilities. It is consistent with the types of methods contained in other GHG reporting programs (e.g., the California mandatory reporting rule, WCI, RGGI, TCR, and Climate Leaders). Because this option specifies methods for each source category, it will result in data that are comparable across facilities.

EPA chose not to adopt simplified calculation methods as a general monitoring approach (e.g., using default emission factors) because the data would be less accurate than under the selected option and would not make use of site-specific data that many facilities already have available and refined calculation approaches that many facilities are already using. EPA is not allowing reporters full flexibility to use any method because the accuracy and reliability of the data would be unknown. Because consistent methods would not be used under such an approach, the reported data would not be comparable across similar facilities.

While the general approach is unchanged, it is important to note that EPA has made changes to the General Provisions and to the specific monitoring requirements for particular source categories in response to public comments on the proposal. EPA has added to the General Provisions (40 CFR part 98, subpart A) an accuracy specification of plus or minus five percent for the calibration of flow meters used to collect data for the emissions calculations under this rule. It provides procedures for calculating calibration error, including specific procedures for orifice, nozzle, and venturi flow meters. Given the comments that were submitted regarding concerns on the timing of performing meter calibration, EPA is providing flexibility to reporters subject to certain operational limitations. For example, facilities that operate continuously may postpone calibration until the next scheduled maintenance outage to avoid operational disruptions.

Individual rule subparts for each source category, rather than the General Provisions, contain the specific monitoring methods for that source category. Comments received on the specific methods are described and responded to in Section III of this preamble and in the relevant source category volumes of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.'' Where appropriate, the final rule has been modified based on those comments. For example, since proposal, in response to public comments, EPA has made changes to individual subparts of 40 CFR part 98 to clarify when CEMS and CEMS upgrades are required and has made other changes to reduce the monitoring burden. Interested parties are encouraged to review the relevant sections of the preamble and rule. Furthermore, some subparts for which significant monitoring approach comments were received are not included in the final rule and will be finalized later as explained in Section II.D of this preamble. These changes to the rule address monitoring approach concerns raised by some commenters.

Comment: Some commenters expressed concern that duplicative reporting would occur if the rule was interpreted to require a reporter to submit data on general stationary fuel combustion emissions at a facility both under 40 CFR part 98, subpart C and also under one of the other source category subparts that applies to the same facility. Some of them indicated that language used in the source category subparts to reference subpart C was not sufficiently clear and consistent. Other commenters indicated the proposed rule was not clear about whether CEMS can be used to report combustion emissions, process CO_2 emissions, or combined emissions.

Response: EPA reviewed each subpart in light of these comments and acknowledges that the proposed rule language referencing 40 CFR part 98 subpart C and the language discussing the of CEMS was inconsistent between subparts and was not always clear. EPA has revised the final rule to clarify our intent.

As indicated by the commenters, many manufacturing facilities are subject to one of the source category subparts and also to the general stationary fuel combustion subpart. For most facilities, emissions from stationary fuel combustion sources (e.g., boilers or engines) are emitted from separate equipment and through separate stacks/emission points than process GHG emissions covered by 40 CFR part 98, subparts E through GG. We have edited the rule to make it clear that in such cases, the reporter would report stationary fuel combustion emissions under 40 CFR part 98, subpart C, and they would report process GHG emissions under each applicable source category subpart.

We have further clarified those source category subparts that require reporting of process CO_2 emissions. We have made it clear that the reporter can elect to monitor and report process CO_2 emissions by either: (1) Installing and operating CEMS and following the Tier 4 methodology in 40 CFR part 98, subpart C, or (2) using the source category-specific monitoring and calculation procedure specified in the subpart. In either case, process CO_2 emissions would be reported under the source category subpart. The source category subparts have also been revised to specify that if process CO_2 emissions are comingled with and emitted through the same stack as emissions from combustion units or process equipment required to use CEMS, than the reporter must use the CEMS and follow the Tier 4 methodology to report combined emissions from the common stack under the specified subpart. This approach makes sense for comingled emissions because CEMS accurately measure total stack CO_2 emissions and the reporter would not be able to accurately separate the fraction of the CO_2 emissions that came from the combustion units and process emission points that are comingled in the same stack.

Source categories with direct-fired equipment (e.g., kilns, furnaces) present a special situation. Examples include cement production, glass production, lead production, lime manufacturing, and soda ash manufacturing. In direct-fired units, fuel combustion emissions and process emissions are both generated within the kiln or furnace and are always emitted together. If CEMS are used on such units, the CEMS will always be measuring combined combustion and process emissions. The language regarding CO_2 reporting and use of CEMS for these source categories has been clarified and harmonized to reflect this situation.

- For kilns or furnaces in these source categories that have CEMS in place and meet specified conditions, the reporter must use the CEMS and follow Tier 4 methodology to determine combined process and combustion CO_2 emissions. The combined emissions are reported under the relevant source category subpart (e.g., for cement production, combined combustion and process emissions from a kiln with a CEMS would be reported under 40 CFR part 98, subpart H, Cement Production).
- For other kilns or furnaces in these source categories, the reporter has the choice to (1) install and operate CEMS to measure combined process and combustion CO_2 emissions, or (2) calculate process CO_2 emissions using the source category-specific monitoring and calculation procedures contained in the subpart. If reporters don't have CEMS and choose the source category-specific calculation approach, then they report process CO_2 emissions under the relevant source category subpart, and report combustion emissions under 40 CFR part 98, subpart C (general stationary fuel combustion).

See the sections for the relevant source categories in Section III of this preamble for summary and discussion of the specific monitoring and reporting requirements for each source category.

M. Summary of Comments and Responses on General Recordkeeping Requirements

This section contains a brief summary of major comments and responses on the general recordkeeping requirements contained in the general provisions (40 CFR part 98, subpart A). *See* sections III.C through PP of this preamble for summaries of comments and responses on specific recordkeeping requirements for the individual source categories contained in 40 CFR part 98, subparts C through PP. A large number of comments were received on general recordkeeping requirements covering numerous topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A, Content of the Annual Report, the Abbreviated Emission Report, Recordkeeping, and the Monitoring Plan'' and in the individual source category volumes of ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.''

1. Record Retention

Comment: Several commenters suggested that EPA require retention of records for three years rather than the five years specified in the proposed rule. Some of these commenters stated that three years is consistent with ARP, which is a comparable program that requires electronic reporting of similar, detailed data. Many contended that retaining the large amount of data required by this rule for five years rather than three years is overly burdensome and is not necessary. They indicated that three years of records is sufficient to allow verification of annual GHG reports. A smaller number of commenters supported record retention for five years, which is consistent with permitting and other programs.

Response: In response to public comments, EPA has changed the record retention requirement in the final rule from five years to three years.[19] We agree that a 3-year time period is sufficient to allow for EPA audit and review of records needed to verify the emissions data submitted in annual reports. Changing the record retention duration to three years will reduce the recordkeeping burden for many facilities reporting under this rule. As stated by various commenters, a 3-year record retention requirement would be consistent with the recordkeeping provisions of the ARP and other Federal reporting programs, including the TRI rules and the DOE Energy Information Administration's 1605(b) Voluntary Reporting of GHG Emission and Reductions program.

2. Monitoring Plan

Comment: We received several comments on the QAPP recordkeeping requirement in proposed 40 CFR 98.3(g). Some had questions about the content and level of detail required in the QAPP, and indicated it would be a costly and burdensome requirement. Others stated that the QAPP would be duplicative of their facility SOPs or documentation kept under ARP or other programs. Some commenters indicated that the list of items to report in 40 CFR 98.3(g) was repetitive because a few of the items listed separately would typically be contained in a QAPP.

Response: The final rule requires a ''monitoring plan.'' The ''QAPP'' terminology in the proposed rule caused confusion because ''QAPP'' is used in a variety of other contexts, has various connotations to different readers, and caused readers to presume requirements EPA did not intend. The final rule specifies monitoring plan contents such as:

- Identification of persons responsible for collecting emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG emissions calculation.
- Description of the procedures that are used for QA, maintenance, and repair of all CEMS, flow meters, and other instrumentation used to provide data for the GHG emissions reported under 40 CFR part 98.

The first two items in this list were formerly listed as separate line items in the recordkeeping requirements, but would logically be a part of the monitoring plan, so were consolidated under the monitoring plan to avoid repetition.

The monitoring plan paragraph in the final rule explicitly states that the monitoring plan can rely on references to existing corporate documents. Such documents include SOPs, QA programs under Appendix F to 40 CFR part 60 or Appendix B to 40 CFR part 75, and other documents provided that the information required by the monitoring plan is clearly recognizable. The provision allowing the monitoring plan to refer to such documents avoids duplicative effort and addresses the commenters' concerns that monitoring plan information is already contained in other documents.

The final rule also contains a provision to update the monitoring plan. Reporters need their monitoring plan to be up to date in order to ensure that facility or supplier personnel follow the right monitoring and QA procedures and that the reporter meets the requirements of the reporting rule. Likewise, EPA needs to be able to view an up-to-date monitoring plan during facility audits. Updates to the plan would be needed if, for example, the facility makes a process change, changes monitoring instrumentation or QA

[19] As described earlier in this section, facilities or suppliers that have emissions or products with emission less than 25,000 metric tons CO_2e for five years in a row may cease reporting. Those that cease reporting must have records to cover those five years of emissions. Similarly, reporters who demonstrate emissions less than 15,000 metric CO_2e for three years is a row may cease reporting, and must have records to cover those three years of emissions.

procedures, or improves procedures for maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

N. Summary of Comments and Responses on Emissions Verification Approach

This section contains a brief summary of major comments and responses on emissions verification of the GHG reports. A large number of comments 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, Approach to Verification and Missing Data.''

Comment: Many commenters, including most facilities and suppliers required to report under the rule and several other stakeholders, supported EPA's proposal to require self-certification with EPA verification of GHG reports. These commenters provided a variety of reasons. Many supported EPA emissions verification because the alternative of third party verification would be more costly to reporters. Several also commented that EPA emissions verification would provide a consistent and transparent data set.

Other commenters suggested that EPA require third party verification of GHG reports, and they provided a variety of reasons. A few noted that third party verification is consistent with other GHG reporting systems (e.g., the European Emissions Trading Scheme, The Climate Registry, the California mandatory GHG reporting rule, and other State programs). Many stated that third party emissions verification will improve the quality of the data submittals and told us that third party verification led to the correction of inaccuracies in GHG emission reports submitted under other programs. Some of the commenters questioned whether EPA would have the time to conduct verification, given the number of reports and volume of supporting data that must be submitted. Others were concerned that EPA verification requires submittal of detailed supporting data and contended that some of these supporting data would be CBI.

A smaller number of commenters favored self-certification without independent emissions verification. They believed the designated representative provisions in the rule would cause reporters to take self-certification seriously and ensure the emissions they report are correct. Some also stated that independent verification is not needed for a reporting program that does not require emissions reductions.

Response: In selecting the approach to emissions verification, EPA reviewed all of the comments, as well as emissions verification requirements and procedures under a number of existing EPA regulatory programs and domestic and international GHG reporting programs. Based on this review, EPA considered three alternatives: (1) Self-certification without independent verification, (2) self-certification with third party verification, and (3) self-certification with EPA verification. For this particular program, EPA is not changing the verification approach from the proposal and is requiring self-certification with EPA emissions verification. We decided to retain this verification approach because it provides greater assurance of accuracy and impartiality than self-certification without verification, and has a number of advantages over third party verification for this type of Federal program. Our objective with emissions verification in this program is to ensure collection and dissemination of high-quality data while providing the reporters a ''level playing field'' in terms of requirements and process.

To enable effective review of the large volume of data reported, the rule requires reporters to submit data electronically in a standard format through a centralized data system. EPA is developing this system and intends to make it available to reporters, along with training and instructional materials, before the reporting deadlines. To the extent possible, EPA will leverage existing reporting systems and work with other State and regional programs and systems to develop a reporting scheme that minimizes the burden on reporters.

In implementing the emissions verification under this rule, EPA envisions a two step process. First, we will conduct an initial centralized review of the data which will be largely automated. EPA intends to build into the data system an electronic data QA program for use by reporters and EPA to help assure the completeness and accuracy of data. In addition, to verify reported data and ensure consistency, EPA may review facility-level monitoring plans and procedures, and will perform detailed, automated checks on data utilizing recent and historical data submittals, comparison against like facilities and/or other electronic audit tools where appropriate. Second, EPA intends to follow-up with facilities should potential errors, discrepancies, or questions arise through the review of reported data and conduct on-site audits of selected facilities. The on-site audits may be conducted by private verifiers contracted by EPA or by Federal, State or local personnel, as appropriate. We plan to coordinate closely with the States to develop an efficient approach toward on-site auditing that can meet the needs of multiple programs. We do not anticipate conducting on-site audits of every facility every year.

EPA decided to finalize the rule with EPA emissions verification for several reasons. First, we determined that the combination of comprehensive electronic review and a flexible and adaptive program of on-site auditing will enable us to effectively target verification resources while also providing the necessary consistency and quality in the data. Utilizing the national data set developed under this rule will provide unique resources for the review of reports. A centralized emissions verification system provides greater ability for EPA to identify trends and outliers in data and thus assist with targeted follow-up review, and our approach can evolve over time as we gain experience with GHG reporting. This approach also provides opportunity to work closely with and leverage both the experience and ongoing activities of States and others already engaged in similar and different types of GHG reporting.

Our emissions verification approach in this rule is consistent with other EPA emission reporting programs and follows a model similar to the ARP which is a highly successful emissions cap and trade program that consistently produces credible, high-quality data. Facilities regulated under ARP must have a Designated Representative sign data reports to self-certify that the reported data are accurate. Then, facilities and EPA use a series of electronic tools to ensure proper data collection and reporting, including establishing a monitoring plan, calibrating equipment to certain specifications, frequent testing and data submittal. Similar to what we are intending with this program, EPA conducts site audits on those facilities targeted during the electronic review as having been outliers or had anomalies in their reported data. These audits are done by EPA personnel, States and/or contractors to EPA. We support these audits by providing a field audit manual to both government and private auditors as well as additional training to State and Federal auditors.

Second, this approach is the best way to address the many comments we received on the importance of obtaining 2010 data and making the data widely available. EPA has determined that this verification approach will enable us to make data available more quickly than under a third party verification approach. We will be able to share a complete data set promptly upon completion of the electronic review (subject to relevant CBI concerns, please see the discussion of our plans to address CBI and emissions data in Section II.S of this preamble and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues''). We determined that the third party verification approach could take from three to six months after initial data submission, and EPA would still need to review and perform consistency checks after the third party verification was complete.

In addition, developing the third party verification approach would require EPA to establish and develop emissions verification protocols and a system to qualify and accredit the third party verifiers, and to develop and administer a process to ensure that verifiers hired by reporting facilities do not have conflicts of interest. Such a program could require EPA to review numerous individual conflict of interest screening determinations made each time a reporter hires a third party verifier. Even if EPA were to partner with an existing program or organization to accredit verifiers, EPA would still need to develop the criteria and systems described above to implement this rule and ensure high quality emissions verification given the unique reporting requirements of this rule. These efforts would slow down implementation of the rule and sharing of data.

Finally, we agree with many of the commenters regarding their concerns about the cost of third party verification. Given the information currently available to us, under a third party verification approach we would have required that each facility verify its submission each year. As a national reporting program with a substantially larger number of reporters than existing State programs, we determined that the costs to the reporters of third party verification would have been substantial. By finalizing self-certification with EPA emissions verification for this rule, it also ensures a lower cost burden for reporters.

EPA's decision to use self certification with EPA emissions verification was made in the context of the specific scope of this rulemaking, the types of data to be collected, and the intended uses of the emissions data. For other types of programs (e.g., offsets, corporate footprinting, energy efficiency) other verification approaches may be more suitable. We recognize that many GHG reporting and reduction programs developed by the States and Regions are broader in scope and for this and other reasons, the use of third party verifiers is an appropriate way to verify the data they collect. EPA's decision in this rulemaking does not preempt State GHG reporting programs or any other programs from requiring third party verification. More importantly, the selection of EPA emissions verification for this rule is not intended to suggest that third party verification cannot result in accurate, high quality data.

EPA received a smaller number of comments in support of self-certification without emissions verification. While recognizing that this approach would place a low burden on both reporters and the government, it also has major disadvantages. Without any verification of submitted reports, there is far greater potential for inconsistent and inaccurate data and this will result in less confidence at EPA and with public stakeholders in the data. These disadvantages would make the data collected under this option less useful for informing decisions on climate policy and supporting the development of potential future policies and regulations.

Comment: Commenters asked what role State and local regulatory agencies will have in verification of reported emissions data. Some suggested that State and local agencies should assist with emissions verification because they already have detailed knowledge of the facilities in their areas. Some indicated that States would need resources to play a role in verification and other rule implementation activities.

Response: While EPA is responsible for emissions verification as explained in the previous response, EPA will likely enlist State assistance, when it is available, during the implementation phase of the final rule. (However, State and local agencies will not be required to provide EPA any assistance with verification or implementation activities, given State and local agency resource constraints and priorities.) For example, in concert with their routine inspection and other compliance and enforcement activities for other CAA programs, State and local agencies could, as resources allow, assist with educating facilities and assuring compliance at facilities subject to this rule.

Assistance from State and local agencies could include such activities as identifying the facilities for on-site audits or conducting audits where appropriate. This type of assistance from State and local governments has been valuable in other programs. State and local air pollution control agencies routinely interact as part of other regulatory programs with many of the sources that would report under this rule. States have knowledge of specific facilities and sources that would be required to report under this rule. In addition, many States have already implemented or are in the process of implementing GHG reporting and reduction programs. Therefore, some State and local agencies could serve a role in communicating the requirements of the rule and providing compliance assistance.

O. Summary of Comments and Responses on the Role of States and Relationship of This Rule to Other Programs

This section contains a brief summary of major comments and responses. A large number of comments on the relationship between this rule and other programs 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, Relationship to Other GHG Reporting Programs'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Comment: Several commenters requested that EPA make it clear that States can collect additional GHG data under State rules and GHG programs and are not limited to collecting only the data in this Federal mandatory reporting rule. Other commenters requested that this rule preempt or supersede State GHG reporting rules.

Response: EPA reaffirms that States can collect additional data under State rules and GHG programs, and that this rule does not preempt or replace State reporting programs. This rule has been developed in response to a specific request from Congress (in the Appropriations Act) and is narrower and more targeted than many existing State programs that are coupled with GHG emission reduction programs. As EPA stated in Section II of the proposal preamble (74 FR 16457, April 10, 2009) and Section I.E of this preamble, many State programs 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.

EPA supports and recognizes the success and necessity of State programs as a vital component in achieving GHG emissions reductions, particularly those focused on energy efficiency improvements. It is appropriate that State and regional GHG reporting and reduction programs have different scopes or implementation schedules, and that they require reporting of different information than this rule for various program-specific reasons. For example, some State programs might require reporting of electricity purchases and other data to provide information for energy efficiency programs; they may require or allow reporting of a variety of indirect emissions to gather data to help facilities reduce their carbon footprint; they may require or allow reporting of emissions such as from fleet vehicles to encourage fleet operators to take steps to reduce emissions; or they may be developing or implementing GHG reduction rules including cap and trade programs, and require specific information on emissions and offsets to implement those programs. State programs already have, or may evolve to include, additional monitoring and reporting requirements than those included in this rule. Many States are actively collecting additional data they need for their programs and policies, and this reporting rule does not preempt State programs.

Comment: Some commenters were concerned that the Federal GHG reporting rule will result in duplicative reporting for facilities that are also reporting GHG emissions under State rules or voluntary GHG reporting programs. Some requested that to reduce burden, facilities should be required to submit data only once, and not have to submit different data to multiple different programs. Some commenters strongly recommended that the electronic data systems used by this reporting rule and other programs need to be consistent and allow data exchange between this rule and TCR, State rules, National Emissions Inventory (NEI), ARP, or other programs. Many commenters supported submittal of all data directly to EPA, while others favored delegation of data collection to State agencies to encourage consistency between State and Federal data collection efforts.

Response: EPA carefully considered the issue of State delegation, particularly in light of the leadership and experience of several States in developing GHG reporting and reduction programs, and also in the context of the pressing need for a national reporting program and the strong emphasis placed by the vast majority of the commenters on this rule for EPA to ensure that data collection begins on January 1, 2010 and that data are reported early in 2011. We determined that developing a program to delegate to States would take additional time and would not be available for 2010 reporting, and we also determined that a significant number of States would likely not request delegation, which would increase the complexity of assembling a consistent national data set. For these reasons, we determined that the most effective way to achieve nationwide GHG reporting of 2010 data was for reporters to submit data directly to EPA, as proposed. Additional reasons for selection of this data flow approach are described in the response on emissions verification in Section II.N of this preamble, the responses on collection, management, and dissemination of GHG emissions data in Section V of this preamble, and the responses on compliance and enforcement in Section VI of this preamble.

While EPA is not formally delegating rule implementation and enforcement to States, we are committed to working in partnership to address the issues expressed in their comments on interaction between State and Federal reporting programs. Design and implementation of electronic systems for data systems has been an area of particular focus in determining how to ease reporting burdens and facilitate use of the many different types of data collected by State and Federal reporting programs by all levels of government.

EPA is committed to working with States 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.

EPA recognizes the need to develop reporting tools that can support reporting across programs that collect different types of data, and we intend to coordinate with States and other organizations to explore development of shared web-based tools that can simplify and expedite reporting. We recognize that State and regional programs may be collecting additional GHG information beyond what is required in this rule. For example, many of these programs collect emissions data on fleet vehicles, indirect emissions data for utility purchase, and other data not required by the Federal rule. Moreover, our rule requires reporting of additional data necessary for emissions verification, which is likely more expansive than what many existing State and regional programs are collecting. For example this rule requires reporting of emissions at the process or unit level for many source categories, rather than the company or facility level as allowed by various other mandatory and voluntary reporting programs. We will also collect detailed monitoring data and activity data used to calculate emissions, which will enable emissions verification. We are interested in working with others to determine the extent to which shared tools can be designed to facilitate reporting across multiple programs, consistent with obligations regarding CBI.

EPA carefully reviewed Federal, State, and international voluntary and mandatory programs during development of the reporting rule and attempted to be consistent with the GHG protocols and requirements within these rules, to the extent feasible given the differing scopes and policy objectives. (*See* Section II of the preamble for the proposed rule (74 FR 16457, April 10, 2009), the Review of Existing Programs memorandum (EPA–HQ–OAR–2008–0508–052), and the memorandum summarizing State mandatory rules (EPA–HQ–OAR–2008–0508–054).) EPA has worked with and will continue to coordinate closely with other Federal, State, and regional programs to facilitate data exchange when designing the data reporting systems that will be used for the rule and planning implementation activities. We will work with the States, TCR, and others on data exchange standards to ease sharing of data between systems, consistent with CBI obligations. And finally, we see substantial opportunities for EPA and States to cooperate on strategic efforts to identify uses of the data collected under this rule and work together on a broad array of climate change issues.

P. Summary of Comments and Responses on Other General Rule Requirements

This section contains a brief summary of major comments and responses on other general rule requirements. A large number of other general comments 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'' volumes on subpart A.

1. Research and Development

Comment: Commenters representing institutions and industries subject to the reporting rule requested an exclusion for R&D activities. They noted that the aluminum production and glass production subparts of the proposed rule excluded R&D process units, but requested that R&D be excluded from the rule as a whole, not only from the two subparts. Some also commented that the exclusion should encompass R&D activities other than R&D process units, including bench scale laboratory research and pilot plants. Commenters pointed out that many other EPA air rules exclude R&D and they explained that R&D activities are small-scale, emissions change frequently as the focus and scope of the R&D activity changes, reliable information on CO_2e emissions during any particular phase of the research might not be available, and quantifying R&D emissions would impose a high burden relative to the quantity of emissions.

Response: In response to these public comments, EPA has added an R&D exclusion in 40 CFR 98.2(a)(5) stating that R&D activities are not considered to be part of any source category defined in 40 CFR part 98. Because R&D activities are not included in any source category, their GHG emissions are not reported. EPA agreed with the commenters that R&D process units and laboratory R&D for new processes, technologies, or products should be excluded. It is not reasonable to calculate GHG emissions from processes and activities that continually change as the research focus changes and have highly variable inputs and operating conditions due to their R&D nature. Also, emissions from R&D are expected to be small. Therefore, the final rule defines R&D as activities conducted in process units or at laboratory bench scale settings whose purpose is to conduct R&D 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.

We point out that the exclusion applies to each individual R&D activity that meets the R&D definition, not to an entire facility as a whole. For example, a facility that has some commercial process units and some R&D process units can exclude only the R&D process units. A facility that meets the applicability criteria in 40 CFR part 98, subpart A and contains general stationary combustion sources must report emissions from the combustion units, even if the steam, heat, or electricity generated by a combustion unit is used in an R&D process unit. Laboratory activities are excluded only if they are for R&D purposes. Laboratory analyses activities conducted for commercial purposes, process operating purposes, or to comply with a rule would not be excluded.

We decided not to include pilot plants in the definition of R&D. Pilot plants that meet the rule applicability criteria must report their GHG emissions. Pilot plants tend to be relatively large in scale compared to the excluded R&D activities. Because pilot plants are designed to prove the viability of a particular process or technology rather than to research a wide range of processes and products, their operations and emissions are more consistent than the excluded R&D activities. Pilot plants also tend to be operated for relatively long periods of time and in some cases are converted to commercial facilities. For these reasons, EPA views the data as more useful and has not applied the R&D exclusion to pilot plants.

2. Determining Applicability

Comment: Some commenters were concerned that the GHG reporting rule will virtually require every commercial and industrial facility to collect fuel usage data and perform relatively complex calculations, and in some cases modeling, in strict accordance with the prescribed monitoring methodologies and emissions calculation procedures, to determine if they are subject to the rule. The commenters added that this will be burdensome, especially for small sources that will just be documenting that the calculated GHG emissions from the facility are well below the reporting threshold. They also indicated that recordkeeping would be needed to show that facilities are below the reporting threshold, and anticipated that the rule will be nearly as burdensome on facilities that do not have to report, as on those that must report. Many of the commenters asked that EPA provide simplified source category thresholds to determine applicability, like the 30 mmBtu/hr aggregate maximum rated heat input capacity for stationary fuel combustion units, to reduce the burden on the majority of facilities making applicability determinations.

Response: We disagree that the initial applicability determination process is burdensome. While the rule requires reporters who are subject to the rule to determine applicability using the calculation procedures required in the rule, the rule does not contain any requirements for facilities that are not subject to the rule. Therefore, the rule does not necessarily require monitoring in 2010 to determine applicability. To determine applicability, anyone who believes their facility might be subject to the rule could start by calculating emissions using the relevant equations provided in each applicable subpart along with the available data from company records and the likely operating scenario for the reporting year that would lead to worst case GHG emissions. For example, for the input parameters needed for the equations, use the 2010 production goals from the company's business plan, company records, process knowledge, engineering judgment, and vendor data (e.g., vendor information could be used to estimate the carbon content of feedstocks, using the highest likely carbon content of those feedstocks.) EPA expects that for most facilities, emissions calculated in this manner are likely to be significantly above or below the 25,000 metric ton CO_2e per year threshold, such that most potential reporters can determine their applicability to the rule solely using the available data.

For those facilities with estimated emissions that are near the 25,000 tons/year threshold using available data, the company will have to make the decision on whether to install monitoring equipment to calculate emissions during the 2010 reporting year for purposes of determining applicability and/or reporting emissions. It is in a facility's interest to collect the GHG data required by the rule if they think they will meet or exceed the applicability criteria in 40 CFR 98.2 by the end of the year. EPA anticipates that relatively few potential reporters will face uncertainty in making this decision.

Given the large number of industrial and commercial facilities potentially subject to the rule due to stationary fuel combustion emissions, EPA has provided in 40 CFR 98.2 simplified procedures for calculating emissions from fuel combustion. These facilities may first assess applicability based on the aggregate heat input capacity of all their fuel combustion units. Per 40 CFR 98.2(a)(3), facilities with an aggregate maximum rated heat input capacity of less than 30 mmBtu/hour are automatically not covered under the rule, because emissions of CO_2e will be less than 25,000 metric tons of CO_2e per year in all cases. If a facility is not below the 30 mmBTU/hour cutoff, the next logical step to determine applicability is to use any of the four calculation methods provided in subpart C, as allowed by 40 CFR 98.2(b). The simplest of the four methods requires determination of only one parameter—

annual fuel use. Most companies already record fuel use, and can use this to calculate emissions and determine applicability.

To assist facilities in determining applicability, EPA plans to provide implementation guidance with simplified means to determine applicability. For combustion sources, EPA plans to publish tables that will specify by fuel type both an annual fuel consumption level and maximum heat input capacity that correlates with emissions of 25,000 metric tons per year of CO_2e. For non-combustion source categories with a 25,000 metric ton CO_2e threshold, EPA plans to publish guidance, as feasible, on equipment capacities, production levels, or other parameters that correlate with emissions of 25,000 metric tons per year of CO_2e. The capacity and production levels provided in these tables would be based on worst-case assumptions, but would allow facilities to quickly and easily determine if they need to develop more precise estimates or plan to implement monitoring in 2010.

Q. Summary of Comments and Responses on Statutory Authority

This section contains a brief summary of some major comments and responses. A large number of comments on statutory authority were received covering numerous topics. This section will highlight only two of the key categories of comments. Additional discussion on these comments and others can be found in the comment response documents.

Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues''.

Comment: EPA received numerous comments on whether the CAA or the FY 2008 Consolidated Appropriations Act authorized the rule. Some commenters argued that EPA was required to issue the reporting rule under the authority created by the Appropriations Act, not the CAA. Others argued that the Appropriation Act could not create new authority, and therefore either (1) EPA had to rely on the CAA, or (2) EPA was not authorized to issue the rule at all.

Response: As noted above, EPA is relying on the authority provided in the CAA, not the Appropriations Act, for this final rule. While the Appropriations Act required that EPA spend a certain amount of money on a rule requiring mandatory reporting of GHG emissions, the authority to gather such information already existed in the CAA. Indeed, EPA could have promulgated this rule in the absence of the Appropriations Act. Thus, the comments about the inability of an appropriations law to create new legal authority are inapposite to this rulemaking.

Comment: Commenters opined on whether the statute in question (either the Appropriations Act or the CAA) contained sufficient authority for various elements of the rule, ranging from broad issues like the scope and duration of the rule as a whole, to more specific issues related to particular source categories covered, and specific monitoring, recordkeeping and reporting requirements.

Several commenters argued that the appropriations language contained limitations on the scope of the rule EPA could promulgate, regardless of the underlying authority for the rule. For example, some commenters contended that because the appropriations were for a single fiscal year, EPA was authorized to promulgate only a one-time data collection. Others argued that the Appropriations Act authorized the collection solely of GHG emissions, and not any of the additional data elements related to verification of emissions data.

As for the CAA, some commenters questioned whether section 114 authorized a broad reporting rule, as opposed to the targeted 114 information requests used by EPA in the past. Many commenters questioned whether EPA had adequately linked the requirements of the reporting rule to particular provisions of the CAA that EPA was carrying out. Others questioned EPA's general ability to gather information about GHGs before it had made an endangerment finding and/or regulated GHGs under the CAA.

Not all comments were negative. Some commenters supported EPA's interpretation of the CAA, and agreed that it authorized the proposed reporting rule.

Response: We disagree that the language in the Appropriations Act limited EPA's authority for this rule. First, the Environmental Programs and Management (EP&M) funds Congress appropriated for the GHG reporting rule are available for two fiscal years as are the funds EPA historically has used for most other Agency rules. The fact that the appropriations EPA uses to develop rules are available for specified fiscal years does not mean that the effectiveness of the rules is limited by the same period of time that the funds are available. Moreover, as noted above, EPA is issuing this rule under the authority of the CAA, and indeed EPA could have issued this rule absent the direct instruction from Congress to spend at least a certain amount of money on a mandatory GHG reporting rule. Thus, we do not agree that the appropriations language limited EPA's ability to collect the information under this rule, either in duration or scope of the information requested.

Regarding the scope of the rule, while it is true that EPA has used section 114 in a more targeted fashion in the past, there is nothing in the CAA that so limits our ability. EPA is undertaking a comprehensive evaluation of GHGs under the CAA and hence, is issuing a comprehensive reporting rule.

Moreover, as noted above, CAA sections 114 and 208 authorize EPA to gather the information under this rule, which will prove useful to EPA in carrying out numerous provisions of the CAA. This final rule imposes requirements on direct sources of GHG emissions. These sources are clearly persons from whom the Administrator may gather information under CAA section 114, as long as that information is for purposes of carrying out any provision of the CAA. As discussed further in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'' and ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues,'' the information provided by direct emitters will prove invaluable to the Agency in several areas, including the evaluation of the appropriate action to take under section 111 regarding NSPS, and the investigation into non-regulatory strategies to encourage pollution prevention pursuant to section 103(g). For example, the Agency currently has pending before it a court remand, comments in an ongoing rulemaking, a petition for reconsideration, notices of intent to sue and litigation regarding EPA's treatment of GHGs under section 111.

The requirements applicable to manufacturers of mobile sources are authorized by section 208 because they will help inform various options regarding the regulation of these sources under title II of the CAA. The Agency currently has pending before it several petitions requesting that the Agency regulate emissions from a variety of mobile sources, including motor vehicles, aircraft, nonroad engines and marine engines.

Finally, the final rule also gathers information from upstream suppliers of industrial GHGs and fossil fuels (except for suppliers of coal). The information gathered from suppliers of fossil fuels, in particular petroleum products, is relevant to an evaluation of possible regulation of fuels under title II of the

CAA, as well as for potential efforts to address GHG emissions at downstream sources. Information from suppliers of industrial GHGs is relevant to understanding the quantities and types of gases being supplied to the economy, in particular those that could be emitted downstream which will aid in evaluating action under CAA section 111 as well as various sections of title VI (e.g., 609 and 612) that address substitutes to ozone depleting substances (ODS). Additional discussion on this issue is available in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Selection of Source Categories to Report and Level of Reporting'' and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues.''

Finally, we disagree with commenters who argue that we cannot use CAA sections 114 of 208 to gather information on a pollutant until we have issued an endangerment finding for that pollutant, or actually decided to regulate it under the CAA. The statute is not so inflexible. [20] For example, the information collected under sections 114 and 208 could inform the contribution element of endangerment determinations (e.g., whether emissions from the relevant sector contribute to air pollution which may reasonably be anticipated to endanger public health or welfare). Similarly, information gathered under these sections could inform decisions on whether to regulate a pollutant or source category. Commenters' interpretation would prevent EPA from gathering information that could be critical to key decisions until after those decisions are made. EPA does not agree with, and will not adopt, such an interpretation.

Thus, as discussed in more detail above and in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues,'' EPA has adequate authority to issue this rule.

R. Summary of Comments and Responses on CBI

This section contains a brief summary of major comments and responses on CBI issues. A large number of comments 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, Legal Issues.''

[20] We note that the statute is ambiguous, and thus EPA may adopt any reasonable interpretation. *See Chevron* v. *NRDC et al.,* 467 U.S. 837, 864 (1984).

Comment: EPA received numerous comments addressing the issue of CBI. Industry commenters generally expressed concern that much of the information reported under this rule would be CBI (e.g., production and process data). Many commenters also presented arguments regarding why certain information would not be ''emissions data'' under the CAA. Among the various recommendations were that the final rule (i) not require the reporting of such information at all, (ii) require only that the source maintain such information on site, but not report it to EPA, and/or (iii) clearly state that some classes of information are CBI. Some commenters expressed concern about EPA's ability to maintain the confidentiality of CBI, and thus suggested that EPA should provide further detail regarding how we will protect CBI from disclosure. The agricultural industry expressed particular concerns about making information about the location of facilities public due to concerns about biosecurity and other potential threats. Other commenters favored the wide dissemination of information, and argued that the information gathered under this rule should be ''emissions data'' and hence not protected as CBI.

Response: As discussed in Section II.N of this preamble, EPA is finalizing its proposal that EPA verify the information collected by this rule. Data regarding inputs into emissions calculations and monitoring are critical elements of that verification process. Because EPA will routinely need this data in order to verify the information collected under this rule, we are not adopting the recommendation that sources maintain such information on site and only provide it during an inspection or when otherwise specifically requested.

EPA also recognizes the importance of this issue to both reporters and the public. EPA's public information regulations contain a definition of ''emissions data'' at 40 CFR 2.301, and EPA has discussed in an earlier **Federal Register** notice what data elements constitute emissions data that cannot be withheld as CBI (56 FR 7042–7043, February 21, 1991). We further recognize that while determinations about whether information claimed as CBI meets the definition of CBI, as well as whether it meets the definition of emissions data, are usually made on a case-by-case basis, such an approach would be cumbersome given the scope of this rule and the potential inconsistencies across reporters and source categories and the compelling need to make data that are not CBI, or are emissions data, available to the public. For this reasons, EPA intends to undertake an effort similar to what was done in 1991 for the data elements collected in this rule. Through a notice and comment process, we will establish those data elements that are ''emissions data'' and therefore will not be afforded the protections of CBI. As part of that exercise, in response to requests provided in comments, we may identify classes of information that are not emissions data, and are CBI. EPA plans to initiate this effort later this year, or in early 2010. We will consider the comments received on this issue as part of that notice and comment process.

As stated in the proposed rule, EPA will protect any information claimed as CBI in accordance with regulations in 40 CFR part 2, subpart B. As we noted previously however, in general the CAA prohibits the treatment of emission data collected under CAA sections 114 and 208 as CBI.

S. Summary of Comments and Responses on Other Legal Issues

This section contains a brief summary of major comments and responses on other legal issues. A large number of other legal issue comments 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, Legal Issues.''

Comment: We received numerous comments on EPA's statements in the proposed rule that a final rule requiring the monitoring and reporting of GHG emissions would not render GHGs ''regulated pollutants'' under the CAA. See, e.g., ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008) (''PSD Interpretive Memo). Some agreed, while others took issue with the position in the memorandum.

Response: As we noted in the proposal, EPA is reconsidering the PSD Interpretive Memo and will be seeking public comment on the issues raised in it. That proceeding, not this rulemaking, is the appropriate venue for submitting comments on the substantive issue of whether monitoring regulations under the CAA should make GHGs subject to regulation. At this time however, the PSD Interpretive Memo reflects EPA's current position, and hence, this final rule does not make GHGs subject to regulation under the CAA.

Comment: EPA also received numerous comments about whether the requirements imposed by this rule are ''applicable requirements'' under the title V operating permit program. The majority of the comments took the position that the current definitions of ''applicable requirement'' at 40 CFR 70.2 and 71.2 do not include a rule such as this, promulgated under CAA section 114(a)(1) and 208. Commenters requested that EPA confirm their interpretation of the regulations.

Response: As currently written, the definition of ''applicable requirement'' in 40 CFR 70.2 and 71.2 does not include a monitoring rule such as today's action, which is promulgated under CAA sections 114(a)(1) and 208.

III. Reporting and Recordkeeping Requirements for Specific Source Categories

A. Overview

Once a reporter has determined that its facility or supply operation meets any of the reporting rule applicability criteria in 40 CFR 98.2(a), the reporter must calculate and report GHG emissions or alternate information as required (e.g., suppliers report quantities supplied and the quantity of CO_2e that could be emitted when the products they supply are combusted or used). The applicability threshold determination is separately assessed for suppliers (fossil fuel suppliers and industrial GHG suppliers) and downstream source categories (facilities with direct GHG emissions).

The required GHG information must be reported for all source categories at the facility for which there are measurement methods provided. For suppliers (facilities or corporations) that trigger only the applicability criteria for upstream fossil fuel or industrial GHG supply (40 CFR part 98, subparts KK through PP), reporters need only follow the methods and report the information specified in those respective subparts. For downstream facilities that contain exclusively direct emitting source categories covered in 40 CFR part 98, subparts C through JJ, and are not suppliers, reporters must monitor and report GHG emissions the methods presented in each applicable subpart. Some reporters will need to report under multiple subparts because multiple source categories are collocated at their facility. For example, a facility with petrochemical production processes (described in Section III.X of the preamble), should also review Sections III.C (general stationary fuel combustion), III.G (ammonia manufacturing) and III.Y (petroleum refineries) of this preamble. In some cases, such as petroleum refineries that supply petroleum products and also meet applicability criteria for direct emissions from the refinery, reporters will have to report on both supply operations and direct facility emissions.

Table 2 of this preamble (in the **SUPPLEMENTARY INFORMATION** section of this preamble) provides a cross walk to aid facilities and suppliers in identifying potentially relevant source categories. The cross-walk table should only be seen as a guide as to the types of source categories that may be present in any given facility and therefore the methodological guidance in Section III of this preamble that should be reviewed. Additional source categories (beyond those listed in Table 2 of this preamble) may be relevant to a given reporter. Similarly, not all listed source categories will be relevant to all reporters.

Consistent with the requirements in the 40 CFR part 98, subpart A, reporters must report GHG emissions from all source categories located at their facility including stationary combustion 40 CFR part 98, subpart C) and process emissions (e.g., from adipic acid production, iron and steel production, and other source categories in 40 CFR subparts C through JJ), as well as the required data for any supplier source categories (KK through PP). The methods presented typically account for normal operating conditions, as well as startup, shutdown, or malfunction (SSM), where significant (e.g., HCFC–22 production and oil and gas systems). Although SSM is not specifically addressed for many source categories, emissions calculation methodologies relying on CEMS or mass balance approaches would capture these different operating conditions.

For many facilities, calculating facility-wide emissions will simply involve adding GHG emissions from combustion sources calculated under Section III.C of this preamble (General Stationary Fuel Combustion Sources) and process GHG emissions calculated under the applicable the source category subpart(s). The rule also clarifies reporting for more complex situations, such as where combustion and process emissions are comingled. See Section II.L of this preamble for a response to comments on the general monitoring and reporting approach for facilities with both combustion and process emissions. *See* sections III.C through PP of this preamble for discussion of the specific monitoring and reporting requirements for each source category.

B. Electricity Purchases

1. Summary of the Final Rule

The final rule does not require facilities to report their electricity purchases or indirect emissions from electricity consumption.

2. Summary of Major Changes Since Proposal

There have been no changes since proposal. The proposed rule did not require reporting of electricity purchases and neither does the final rule.

3. Summary of Comments and Responses

The proposal preamble (74 FR 16479, April 10, 2009) requested comments on the value of collecting information on electricity purchases under this rule. It also outlined three options for reporting and requested comments on these options:

- *Option 1:* Do not require any reporting on electricity purchases or associated indirect emissions from purchased electricity as part of this rule.
- *Option 2:* Require reporting of purchased electricity from all facilities that are already required to report their GHG emissions under this rule.
- *Option 3:* Require reporting of indirect emissions from purchased electricity for facilities that exceed a prescribed total facility emission threshold (including indirect emissions from the purchased electricity). Reporting under this option could be either in terms of electricity purchases or calculated CO_2e emission based on purchased electricity.

While EPA is not including reporting requirements for electricity purchases in the final rule at this time, below we have provided a brief summary of major comments and our initial responses. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

In Favor of Collecting Data on Electricity Purchases

Comment: Commenters in favor of collecting data on purchased electricity stated that collection of this data, in conjunction with data on direct emissions from facilities, will present a more comprehensive picture of emissions nationwide. They argued that collection of this data will also serve to spur investment in energy efficiency and renewable energy since companies will want to improve their emissions numbers once the information is made public. Several commenters noted that while this reporting should occur, it should happen at the corporate level, rather than at the facility level. Others stated that the collection should begin at a later time, perhaps in a second phase of this rule.

Response: While EPA is not collecting data on electricity purchases in this rule, we understand that acquiring such data may be important in the future. Therefore, we are exploring options for possible future data collection on electricity purchases and indirect emissions, and the uses of such data. Such a future data collection on indirect emissions would complement EPA's interest in spurring investment in energy efficiency and renewable energy. Energy efficiency is a low cost, vital first step toward reducing GHG emissions. To this end, EPA has in place several programs in which corporations and individual facilities can participate to reduce their contribution to GHG emissions through increased energy efficiency of buildings and industry. These include EPA's ENERGY STAR and Climate Leaders programs.

EPA has been working for more than a decade through the ENERGY STAR program to help companies reduce their energy use through cost-effective energy efficiency investments and practices. ENERGY STAR provides nonresidential building owners and operators and energy intensive industries with a wide variety of tools and resources to assist in their efforts to reduce building energy use. These include an online energy benchmarking and tracking tool called Portfolio Manager, Guidelines for Energy Management, technical resources to assist in assessing building upgrades, and many others.

Through the Climate Leaders Program, EPA works corporate-wide with companies to develop comprehensive climate change strategies. Partner companies commit to reducing their impact on the global environment by completing a corporate-wide inventory of their GHG emissions based on a quality management system, setting aggressive reduction goals to be achieved over 5 to 10 years, and annually reporting their progress to EPA. Through program participation, companies create a credible record or audit of their accomplishments and receive EPA recognition as corporate environmental leaders.

In addition to these programs that support GHG emissions reductions in both the private and public sectors, EPA's Climate and Energy State and Local Program assists governments in their clean energy efforts by providing technical assistance, analytical tools, and outreach support. While EPA assists States in this way, we also have much to learn from their efforts. Throughout the country, States are engaged in activities on energy efficiency, energy auditing, and some collect data on electricity purchases for use in inventories and in energy efficiency programming.

Since the goal of today's rule is to collect data on emissions from downstream direct emitters and upstream production, the collection of indirect emissions will not be included at this time. In exploring the possibility of collecting data on electricity purchases nationwide, EPA will be looking to the States as examples. While facility level collection is a possibility, collection from other sources, such as load serving entities will also be explored. Moreover, the collection of indirect emissions data from the types of facilities covered by this rule (e.g., facilities and suppliers with emissions over 25,000 metric tons of CO_2e) would not provide the complete picture or focus on the types of facilities that likely have large indirect emissions. Reports from additional facilities could be required in any future data collection.

Against Collecting Data on Electricity Purchases

Comment: Many commenters were against the collection of data on purchased electricity for several reasons. Primarily they felt it would constitute double counting if electricity data are collected from electric utilities and EPA also collects the same data from facilities and adds it together. Others stated that collecting information on electricity purchases was outside the scope of the rule, that it is not useful information in attempting to quantify emissions, that it would be burdensome for facilities, and that it is CBI that companies are not able to share with EPA. Those commenters suggested instead the data should come from utilities, as EPA proposed.

Response: The final rule does not require facilities to report their electricity purchases or indirect emissions from electricity consumption. While EPA is not collecting data on electricity purchases in this rule, we understand that acquiring such data may be important in the future. Therefore, we are exploring options for possible future data collection on electricity purchases and indirect emissions, and the uses of such data. In the event that a future data collection effort is pursued, EPA will consider the issues raised by these commenters with regard to the most effective source for this data, and methods to reduce burden on reporting entities.

With regard to, double reporting and/or double counting of the same data, the data collected under this rule is consistent with the appropriations language, and provides valuable information to EPA and stakeholders in the development of climate change policy and programs. Policies such as low carbon fuel standards can only be applied upstream, whereas end use emission standards can only be applied downstream. Data from upstream and downstream sources would be necessary to formulate and assess the impacts of such potential policies. Eliminating reporting by either upstream or downstream sources would not satisfy EPA's data needs and policy objectives of this rule. Any future rule makings to collect data on electricity purchases and indirect emissions will follow a similar approach in order to inform policy decisions.

With regard to CBI, EPA recognizes the importance of this issue to both reporters and the public. EPA's public information regulations contain a definition of ''emissions data'' at 40 CFR 2.301, and EPA has discussed in an earlier **Federal Register** notice what data elements constitute emissions data that cannot be considered CBI (56 FR 7042–7043, February 21, 1991).

As explained in Section II.R. of this preamble, EPA intends to undertake a similar effort regarding the data elements collected in this rule, and any subsequent rules. Through a notice and comment process, we will establish those data elements that are ''emissions data'' and therefore will not be afforded the protections of CBI.

C. General Stationary Fuel Combustion Sources

1. Summary of the Final Rule

Source Category Definition. Stationary fuel combustion sources are devices that combust any solid, liquid, or gaseous fuel to:

- Produce electricity, steam, useful heat, or energy for industrial, commercial, or institutional use; or
- Reduce the volume of waste by removing combustible matter.

These devices include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters.

Portable equipment, emergency generators, and emergency equipment are excluded from this source category. Stationary combustion devices that combust hazardous waste must report emissions only from the co-firing of any fuels that are covered by 40 CFR part 98, subpart C. Flares are also excluded from subpart 40 CFR part 98, subpart C. Flare emissions must be reported only if required by the provisions of another subpart of part 98.

Reporters must submit annual GHG reports for stationary fuel combustion units if the facility meets the applicability criteria in the General Provisions (40 CFR 98.2) as summarized in Section II.A of this preamble.

EGUs that are subject to the ARP and other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75, are covered under 40 CFR part 98, subpart D (Electricity Generation).

GHGs to Report. For stationary fuel combustion, report:

• CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. For each unit, CO_2, CH_4, and N_2O emissions must be reported for each fuel combusted (including biomass). Reporters can aggregate emissions from multiple units in certain cases.

• Facility-level CO_2 emissions from combustion of biomass (in addition to unit-level reporting).

GHG Emissions Calculation and Monitoring. Reporters must use the following methodologies to calculate emissions:

• *Calculating* CO_2 Emissions from Combustion: Calculate CO_2 emissions using one of four methodological tiers, subject to certain restrictions based on unit size, type of fuel burned, and other factors. For each Tier, CO_2 mass emissions are determined as follows:

—*Tier 1:* Use annual fuel consumption (from company records) together with fuel-specific default high heat values and default CO_2 emission factors.

—*Tier 2:* Use annual fuel consumption (from company records) together with measured fuel-specific high heat values and default CO_2 emission factors.

—*Tier 3:* Use annual fuel consumption, either from company records (for solid fuels) or directly measured with fuel flow meters (for liquid and gaseous fuels) together with periodic measurements of fuel carbon content.

—*Tier 4:* Use CEMS. Use Tier 4 only for combustion units that have certain types of existing CEMS in place and that meet several other specific criteria, such as fuel type and hours of operation. Sources that have all of the necessary CEMS installed and certified by January 1, 2010 are required to use Tier 4 in 2010. However, for sources that need additional time to upgrade their CEMS, the use of CEMS can begin on January 1, 2011; and a lower tier calculation methodology may be used in 2010.

—As an alternative to any of the four tier methods, the rule provides that units that report to EPA year-round heat input data under 40 CRF part 75 can calculate CO_2 mass emissions using part 75 calculation methods.

• *Calculating CO_2 Emissions From Sorbent Use.* For fluidized bed boilers that use sorbent injection and units equipped with wet flue gas desulfurization systems, calculate CO_2 emissions from sorbent use using methods provided in the rule, except when CO_2 emissions are measured with CEMS.

• *Calculating CO_2 Emissions From Biomass Fuel Combustion.* Calculate CO_2 emissions from biomass combustion for only the specific types of biomass that are listed in the rule. The approach used for most units is to use a default high heat value and default CO_2 emission factor to estimate emissions. For determining the biomass fraction of CO_2 emissions from units that burn MSW or mixed fuels, and from units that co-fire biomass with fossil fuels and measure CO_2 emissions using CEMS, use the specific methods provided in the rule.

• *Calculating N_2O and CH_4 Emissions From Combustion.* Calculate N_2O and CH_4 emissions only for units that are required to report CO_2 emissions under this subpart and only for fuels for which default emission factors are provided in 40 CFR part 98, subpart C.

• *Fuel Sampling and Analysis.* The Tier 2 and Tier 3 calculation methodologies require periodic measurements of fuel heating value and carbon content. The minimum required frequency of these measurements is daily, weekly, monthly, quarterly, or semiannually, depending on the type of fuel combusted 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 needed for EPA verification of the reported GHG emissions from stationary combustion. The specific data to be reported are found in 40 CFR part 98, subpart C.

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. These records are described in 40 CFR part 98, subpart C.

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 C: General Stationary Fuel Combustion Sources.''

• Exemptions to GHG emissions reporting have been added for unconventional types of fuel. Reporters are required to calculate GHG emissions only for fuels that are listed in Table C–1 of subpart C, except that units larger than 250 mmBtu/hr, also must calculate GHG emissions for any other fuels that provide, on average, at least 10 percent of the annual heat input to the unit.

• The use of the Tier 2 calculation method for CO_2 emissions has been expanded to include units greater than 250 mmBtu/hr that combust only pipeline natural gas and/or distillate oil.

• Two new alternative methods have been added, allowing sources that monitor and report heat input according to 40 CFR part 75, but are not required to report CO_2 mass emissions, to use established Part 75 CO_2 emissions calculation methods to meet the 40 CFR part 98 reporting requirements.

• A definition of ''company records'', as it pertains to quantifying fuel consumption in Tiers 1, 2, and 3, has been added to 40 CFR 98.6.

• The required fuel sampling frequency in Tiers 2 and 3 has been reduced for many fuels, particularly those that are homogeneous or that are delivered in shipments or lots.

• Averaging of fuel sampling results is allowed for many fuels when the frequency of sampling and analysis is less than the minimum monthly frequency.

• The rule has been clarified to affirm that the use of fuel sampling results provided by the fuel supplier is permissible, and that the use of fuel billing records to quantify fuel consumption is also allowed.

• Additional deadline extensions for calibrating the fuel flow meters are provided in certain situations.

• The use of Tier 4 has been clarified; i.e., all of the conditions listed in 40 CFR 98.33(b)(4)(ii) and all of the conditions listed in 40 CFR 98.33(b)(4)(iii) must be met before Tier 4 is required.

• Units that must upgrade their existing CEMS to meet Tier 4 requirements may use either Tier 2 or Tier 3 in 2010.

• The methods for calculating CH_4 and N_2O emissions have been clarified.

• An expanded list of default emission factors are provided for certain solid, gaseous, and liquid biomass fuels.

• The use of steam production and combustion unit efficiency to calculate CO_2 emissions is extended to other solid fuels in addition to MSW. These parameters may also be used to quantify the amount of biomass combusted in a unit.

- The use of American Society for Testing and Materials (ASTM) Methods D7459–08 and D6866–06a to determine CO_2 emissions from combustion of mixed biomass fuels has been expanded to include the combustion of other biomass fuels in addition to those mixed with MSW.
- The missing data provisions have been made more flexible.
- The limit of 250 mmBtu/hr total heat input for aggregating units into groups for reporting purposes has been lifted.
- The reporting of combined units served by a common supply line, or common pipe configuration, has been clarified.
- The amount of required unit-level data and emissions verification information has been reduced for some of the measurement Tiers.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Many comments on general stationary fuel combustion 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 C: General Stationary Fuel Combustion Sources.''

Definition of Source Category

Comment: Several commenters asked EPA to clarify whether sources such as flares, hazardous waste incinerators, thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and small equipment such as stoves and space heaters are included in the stationary combustion source category. Others suggested that EPA should consider requiring that only the GHG emissions from combustion of traditional fossil fuels (if any) in these types of sources be reported.

Comments were also received on the proposed language for excluding emergency generators and the associated definitions.

Response: The final rule retains the broad definition of a stationary fuel combustion source, which is any device that combusts fuel. Fuel is defined very broadly to mean any combustible material. However, in evaluating public comments, we agree that in some cases the reporting of GHG emissions is unreasonable given the cost of monitoring and the relative level of GHG emissions. Monitoring can be particularly burdensome for vents with highly variable gas characteristics (e.g., carbon content and heat value). Accordingly, the final rule expands the list of combustion sources and fuels that are exempted from GHG emissions reporting under 40 CFR part 98, subpart C, as summarized below:

- Flares are exempted from 40 CFR part 98, subpart C. However, flares at some facilities might be covered by other subparts of the rule.
- Stationary combustion units that combust hazardous waste, as defined in 40 CFR 261.3, are also exempted. These units would report only the emissions from combustion of any fuels covered by subpart C that are co-fired with hazardous wastes.
- For calculations at the unit level, units less than 250 mmBtu/hour heat input are required to report GHG emissions only for fuels for which EPA has provided default emission factors in the rule.
- Units larger than 250 mmBtu/hour heat input GHG that combust miscellaneous, non-traditional fuels such as refinery gas, process gas, vent gases, waste liquids, and others must report only if CEMS are used or if these fuels contribute 10 percent or more of the annual unit heat input to the unit. With this exclusion, we have concluded that devices such as thermal oxidizers, pollution control devices, fume incinerators, burnout furnaces, and other such equipment would report only GHG emissions from the firing of supplemental fossil fuels.

In response to comments on the exclusion of emergency generators, EPA removed proposed language that would have required emergency generators to be identified as such in the facility's State or local air permit in order to qualify for an exemption. We also added language to exclude other emergency equipment. *See* Section III.D of this preamble for the response to the comments on exclusion of emergency generators from 40 CFR part 98, subparts C and D. *See* ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart A: Definitions, Incorporation by Reference, and Other Subpart A Comments'' for responses to comments on definitions, including changes to the emergency generator definition and the addition of a definition for emergency equipment.

Comment: Multiple commenters asked EPA to institute a ''*de minimis*'' provision in the rule to exclude stationary combustion sources other than the largest units at a facility.

Response: The final rule contains no *de minimis* exclusions. However, to simplify reporting, the rule allows small units to be aggregated and reported as a single emissions value, if certain conditions apply. The final rule has expanded the availability of this provision. The proposed rule limited the aggregation of any one group to a combined maximum capacity of 250 mmBtu/hour heat input. The final rule removes this limit and allows grouping of any units that individually are less than 250 mmBtu/hour heat input. EPA has also clarified the use of the common pipe metering option, so that all stationary combustion units at a facility using the same fuel that is metered through a common supply line may report a single emissions value under this rule. In addition, the changes listed above in Section III.C.2 of this preamble will simplify emissions calculations for many combustion units.

Method for Calculating GHG Emissions

Comment: EPA received numerous comments on the proposed GHG calculation methods for stationary combustion sources. Most of the comments centered on the use of the four-tiered approach for calculating CO_2 emissions. Several commenters requested that EPA remove the 250 mmBtu/hr unit size restriction on the use of Tier 1 and 2 calculation methods, especially for the combustion of relatively homogeneous fuels such as natural gas and fuel oil. Objections were raised to the specified frequency of fuel sampling under Tiers 2 and 3, as being excessive and unnecessary. Two commenters recommended that annual sampling be allowed for natural gas and fuel oil. A number of commenters asked the Agency to allow averaging of fuel sampling results (to simplify the CO_2 emissions calculations) and to affirm that the use of fuel sampling results provided by the fuel supplier is permissible. Others sought confirmation that fuel billing meters could be used to quantify fuel usage. Multiple commenters asked EPA to clarify who must use the Tier 4 calculation method, which requires the use of continuous emission monitoring systems (CEMS) to measure stack gas flow rate and CO_2 concentration. A number of comments were received requesting that sources currently monitoring and reporting heat input data under 40 CFR Part 75, but not reporting CO_2 mass emissions, be allowed to implement established Part 75 CO_2 emissions calculation methods in lieu of using Tiers 1 through 4. Finally, EPA received diverse comments on the proposed calculation method for CH_4 and N_2O emissions. Several commenters recommended that these emissions either not be reported at all, or that emissions reporting should be excluded for certain fuel types. Others asked for flexibility in determining the appropriate emission factors for CH_4 and N_2O. Some suggested that the use of operator-defined emission factors or factors from other GHG registries should be allowed.

Response: The final rule significantly expands the use of Tier 1 and Tier 2 calculation methodologies. All units rated at 250 mmBtu/hr or less are allowed to use the Tier 1 or Tier 2 calculation methodologies, depending on fuel sampling provisions at either the facility or by the supplier of the fuel. In addition, units rated at over 250 mmBtu/hr that combust pipeline quality natural gas and distillate oil are allowed to use the Tier 2 calculation methodology, because of the homogeneous nature and low variability in the characteristics of these fuels. However, the 250 mmBtu/hr unit size cutoff remains for units that combust residual oil, other gaseous fuels, and solid fossil fuel.

The mandatory monthly fuel sampling and analysis requirements for traditional fossil fuels have been dropped from Tiers 2 and 3. EPA agrees with the commenters that for a homogeneous fuel such as pipeline natural gas, monthly sampling is not necessary. Therefore, 40 CFR 98.34 has been revised to require that natural gas be sampled semiannually. For other fuels such as oil and coal, which are delivered in shipments or lots, requiring monthly sampling may be impractical, because new fuel lots or deliveries may not be received on a monthly basis. For fuel oil and coal, a representative sample is required for each fuel lot, i.e., for each shipment or delivery. For other liquid fuels and biogas, quarterly sampling is required. For solid fuels other than coal, excluding MSW, weekly composite sampling with monthly analysis is required. For gaseous fuels other than natural gas and biogas, the daily sampling requirement has been retained, but only for facilities with existing equipment in place that is capable of providing the data. Otherwise, weekly sampling is required if such equipment for daily sampling is not installed.

The final rule clarifies that fuel sampling and analysis data provided by the supplier may be used in the emission calculations, and that fuel billing meters may be used to quantify fuel consumption. To simplify the emission calculations in Tiers 2 and 3, arithmetic averaging of higher heating value and carbon content data over the reporting year is permitted if these data are collected less frequently than monthly (*see* Equation C–2b in 40 CFR 98.33). However, regardless of the sampling frequency required by the rule, reporters must use the results of all available valid fuel analyses in the emissions calculations.

Today's rule clarifies the applicability of the Tier 4 methodology. Many commenters were unsure whether only one or all six of the conditions listed in proposed 40 CFR 98.33(b)(4)(ii) and all three of the conditions listed in proposed 40 CFR 98.33(b)(4)(iii) must be met to trigger the requirement to use CEMS. EPA's intent has always been that a source must meet all conditions listed in those sections to require the use of Tier 4. This has been made clear in the final rule text.

The final rule adds two methods that can be used as alternatives to any of the four tier calculation methods. These alternative methods apply to sources that are currently required to monitor and report heat input data according to 40 CFR part 75, but are not required to report CO_2 mass emissions. Many units subject to the Clean Air Interstate Regulation (CAIR) are in this category. These alternative methods allow these sources to use their 40 CFR part 75 heat input data together with one of the CO_2 emissions calculation methodologies in part 75 to meet 40 CFR part 98 CO_2 emissions reporting requirements. For instance, sources monitoring hourly heat input according to Appendix D of 40 CFR part 75 may use Equation G–4 in Appendix G of 40 CFR part 75 to calculate CO_2 emissions. Similarly, low mass emitting sources monitoring heat input under 40 CFR 75.19 may use Equation LM–11 in 40 CFR 75.19 to calculate CO_2 emissions. Sources using 40 CFR part 75 flow rate and CO_2 CEMS to continuously monitor heat input may use the CEMS measurements together with an appropriate equation from Appendix F of 40 CFR part 75 to determine CO_2 mass emissions.

The methodology for calculating CH_4 and N_2O emissions has been clarified in the final rule. Reporting of these emissions is required only for the fuels listed in Table C–2 of 40 CFR part 98, subpart C. Further, reporting of CH_4 and N_2O emissions is required only for units that are required to report CO_2 emissions under 40 CFR part 98, subpart C and only for fuels for which default emission factors are provided in subpart C. The emission factors in Table C–2 of 40 CFR part 98, subpart C are both fuel-specific and heat input-based. Therefore, when more than one type of fuel is combusted in a unit, direct measurements or engineering estimates of the annual heat input from each fuel are needed to calculate the CH_4 and N_2O emissions. Consequently, when CEMS (which are not fuel-specific) are used to monitor the CO_2 emissions and heat input for a multi-fuel unit, the total heat input measured by the CEMS must be apportioned to each fuel type. The owner or operator should use the best available information (e.g., fuel feed rates, high heat values) to do the necessary heat input apportionment. To provide greater consistency in reporting, EPA has chosen to retain the requirements for using the default factors in Table C–2 of 40 CFR part 98, subpart C, rather than allow reporters to select their own emission factors.

Procedures for Estimating Missing Data

Comment: EPA received several requests to modify the proposed missing data substitution procedures in 40 CFR part 98, subpart C. One commenter recommended that a minimum data capture requirement should be specified rather than requiring the use of substitute data to fill in missing data gaps. Another commenter suggested that only the ''before'' value be used for data substitution, rather than the average of the quality-assured values before and after the missing data period. Others favored using emission factors or the ''best available estimates'' for all parameters, rather than following a prescriptive missing data algorithm. Finally, several commenters asserted that 40 CFO part 75 missing data procedures for CO_2 are too conservative (i.e., may overestimate emissions significantly) and seem to be contrary to the objectives of 40 CFR part 98.

Response: The final rule provides additional flexibility to the missing data provisions of 40 CFR part 98, subpart C. The rule requires the use of ''before and after'' average values for only three parameters (fuel HHV, carbon content, and molecular weight). If the ''after'' value is not yet available when the GHG emissions report is due, the ''before'' value may be used for missing data substitution. For all other parameters, the reporter can substitute data values that are based on the best available estimates, based on all available process information.

EPA does not agree with the commenters who believe that the 40 CFR part 75 CO_2 missing data procedures are too conservative and contrary to 40 CFR part 98 program objectives. Nearly all 40 CFR part 75 sources maintain very high monitor data availability (95 percent or better) and use very little substitute data. Only when the data availability drops below 80 percent (which very seldom occurs) are the substitute data values significantly higher than the true CO_2 concentrations. Therefore, sources that monitor CO_2 emissions according to 40 CFR part 75 should continue to use the standard part 75 missing data provisions, and no adjustments to those substitute data values are deemed necessary for 40 CFR part 98 reporting purposes.

Data Reporting Requirements

Comment: A number of commenters objected to the amount of unit-level data and emissions verification information that is required to be reported electronically under 40 CFR 98.36 as ''burdensome'', ''unnecessary,'' and ''excessive.'' The commenters recommended that the auxiliary information should instead be kept on file and made available to EPA upon request. Several commenters recommended that EPA remove the 250 mmBtu/hr limit on the cumulative heat input capacity of units that can be aggregated into groups for reporting purposes. Other commenters asserted that EPA should consider the 40 CFR part 75 emissions data submitted under the ARP to be sufficient to satisfy 40 CFR part 98 requirements, and that there is no need to submit the same data twice.

Response: EPA does not agree with the assertion that the amount of unit-level data to be reported is excessive, burdensome, or unnecessary. For this mandatory GHG emissions reporting rule, two approaches to emissions data verification were considered, EPA verification and third-party verification. The Agency decided on EPA emissions verification. To verify GHG emissions estimates, EPA needs supporting data that are reported at the same level as the emissions are calculated. Because the rule requires that emissions be calculated at the unit level, it is imperative for EPA to obtain unit level verification data, particularly given the variety of requirements for estimating fuel combustion emissions under 40 CFR part 98, subpart C. Subpart C provides four different methods of estimating CO_2 emissions. The four methods require measurement of different parameters to estimate emissions, and the use of the methods is conditioned on a variety of operating factors. In addition, facilities use fuel combustion units of a variety of different sizes, types, and fuel firing scenarios. Under these circumstances, EPA could not verify that the correct methods were selected or applied correctly without unit-level data. If unit-level data were not submitted or were aggregated at a gross level, EPA could not reasonably verify the accuracy of reported facility-wide GHG emissions data, because EPA could not evaluate the relationship between unit capacity, fuel characteristics, fuel consumption, and emissions. However, as explained below, in the final rule EPA has made a number of significant adjustments to the data reporting requirements to clarify requirements and to reduce the reporting burden.

First, for units that use Tiers 1, 2 and 3 to calculate CO_2 mass emissions, the cumulative 250 mmBtu/hr heat input capacity limit on the aggregation of units into groups has been dropped. Rather, the 250 mmBtu/hr restriction applies only to the individual units in a group. Therefore, for reporting purposes, individual units with maximum rated heat input capacities of 250 mmBtu/hr or less may be aggregated without limit into a single group, provided that the Tier 4 methodology is not required for any of the units, and all units in the group use the same calculation methodology for any common fuels that they combust. Units with maximum rated heat inputs greater than 250 mmBtu/hr using Tiers 1, 2, and 3 must report as individual units, unless they burn the same type of fuel and the fuel is provided by a common pipe or supply line. In that case, the owner or operator may opt to aggregate emission for all units fed by the common fuel line. Units using Tier 4 must report as individual units unless they share a monitored common stack.

Second, the rule requires minimal data to be reported for units that monitor and report emissions and heat input data according to 40 CFR part 75. Units that meet these criteria include units that are subject to the ARP, and potentially units that are subject to CAIR, and other programs. The final rule clarifies that 40 CFR part 75 sources must report 40 CFR part 98 GHG emissions data under the exact same unit, stack, or pipe ID numbers that are used for electronic reporting in the part 75 programs (e.g., 1, 2, CT5, CS001, MS1A, CP001, etc.). Even though most 40 CFR part 75 sources report CO_2 mass emissions data to EPA year-round, these data alone are not sufficient to satisfy the Part 98 reporting requirements for the following reasons. The emissions reports required under 40 CFR part 98 are facility-wide reports that require GHG emissions from all stationary combustion units at the facility, whether or not the units are subject to a 40 CFR part 75 program. Many electricity generating facilities have both ARP units and non-ARP units on site. Further, the CO_2 emissions data reported under 40 CFR part 75 are in units of short tons; Part 98 requires reporting in metric tons. Finally, 40 CFR part 98 also requires CH_4 and N_2O emissions to be reported, neither of which are reported under any 40 CFR part 75 program.

Third, the required verification data have been clarified and, in some cases, differ substantively from the proposed rule. No additional verification information is required for sources that monitor and report emissions and heat input data using 40 CFR part 75. This includes sources that elect to use the new alternative calculation methodologies for units monitoring heat input year round according to 40 CFR part 75 programs. For sources using Tiers 1, 2, 3, and 4, the final rule streamlines some of the reporting. Sources using Tier 3 are required to report only monthly averages of fuel carbon content and molecular weight rather than the proposed requirement to submit the results of each individual determination. Sources that use Tier 4 are required to report quarterly cumulative CO_2 mass emissions, rather than daily CO_2 emissions, as proposed. Also, to address concerns raised by some of the commenters, certain data elements need only be retained on file and provided to EPA upon request. These data elements include the methods used for fuel sampling and analysis, the methods used to calibrate fuel flow meters, the dates and results of fuel flow meter calibrations, and the dates and results of CEMS certification tests and on-going QA tests of the CEMS.

D. Electricity Generation

1. Summary of the Final Rule

Source Category Definition. This source category consists of EGUs that are subject to the ARP and any other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75. All other EGUs are part of the general stationary fuel combustion source category and report under 40 CFR part 98 subpart C, if the facility meets the reporting rule applicability criteria. This source category excludes portable equipment, emergency generators, and emergency equipment.

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 annual CO_2, N_2O, and CH_4 mass emissions from each EGU.

GHG Emissions Calculation and Monitoring. For EGUs subject to the ARP and other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40

CFR part 75, the reporter must continue to monitor CO_2 emissions according to 40 CFR part 75. The cumulative CO_2 mass emissions reported in the fourth quarter electronic data reports must be converted from short tons to metric tons, for 40 CFR part 98 reporting purposes. The N_2O and CH_4 emissions must be calculated using fuel-specific default emission factors and heat input measurements in accordance with 40 CFR 98.33(c) in 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 unit-level data and other information that are used to verify the reported GHG emissions. The additional data and information to be reported for this source category are specified in 40 CFR 98.46.

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. The specific records that must be retained for this source category are identified in 40 CFR 98.47.

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 D: Electricity Generation.''

- The source category has been more precisely defined and includes only EGUs subject to the ARP and any other EGUs that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75.
- The proposed emergency generator exclusion language no longer requires that emergency generators be identified as such in State or local air permits.
- A CO_2 calculation methology was provided for units that are not in the ARP, but report CO_2 mass emissions year-round using 40 CFR part 75 methodologies.

3. Summary of Comments and Responses

Definition of Source Category

Comment: Several commenters were concerned that covering non-ARP EGUs in both subparts C and D of proposed 40 CFR part 98 was confusing and repetitive. Several commenters stated that the definition of an EGU is too inclusive and recommended that EPA revise it. The commenters were concerned that any unit, regardless of electrical output, could be identified as an EGU and place a facility in the electricity generation source category. One commenter suggested that a 25 megawatts (MW) threshold should be added to the EGU definition in 40 CFR 98.6 and to 40 CFR part 98, subpart D. A multitude of commenters objected to the language in proposed 40 CFR 98.40 requiring emergency generators to be designated as such in a State or local air permit, in order for the generators to be exempted from GHG emissions reporting. Many of these same commenters recommended changes to the definition of ''emergency generator'' in 40 CFR 98.6, suggesting that the term ''generator'' should be replaced with the term ''reciprocating internal combustion engine (RICE)'', to be consistent with 40 CFR 63.6675, subpart ZZZZ. Others recommended that EPA should also exempt emergency equipment such as fire pumps, fans, etc. from GHG emissions reporting.

Response: The electricity generation source category definition in subpart D (40 CFR 98.40) has been modified based on the comments received. The final rule limits the source category to EGUs that are subject to ARP and to other EGUs that monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75. The final subpart D does not cover any other EGUs. The GHG emissions from other EGUs are covered under subpart C (General Stationary Fuel Combustion).

The definition of an ''emergency generator'' in 40 CFR 98.6, the final rule has been changed to clarify that it includes both RICE and turbines. EPA has also added a definition of ''emergency equipment'' to 40 CFR 98.6, and exempts such equipment from GHG emissions reporting under both 40 CFR part 98, subparts C and D.

The proposed requirements in 40 CFR part 98, subparts C and D for emergency generators to be identified as such in State and local air permits in order to be exempt from GHG emissions reporting has been revised. There is considerable variation from State to State regarding the regulation of emergency generators, including whether or not permits are required. Some States specifically exempt emergency generators from permitting requirements. Other States use a permit by rule approach for emergency units. In view of this, the Agency has revised the wording of the exclusion for emergency generators to allow for situations where they are not specifically identified in a facility's permit.

Method for Calculating GHG Emissions

Comment: Several commenters suggested that for units that are not in the ARP but are required by other regulatory programs to report part 75 emissions and heat input data, EPA should expand the four-tiered calculation method for CO_2 mass emissions in 40 CFR 98.33(a) to allow the use of CO_2 emissions calculation methods based on Appendices D and G of part 75.

Response: The electricity generation source category definition has been narrowed to only include EGUs that are subject to ARP and to other EGUs that monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75 (e.g., RGGI units). The final subpart D provides a CO_2 calculation methodology for such EGUs that are not in the ARP, but report to EPA CO_2 mass emissions year-round using part 75 methodologies. For the purposes of part 98, the CO_2 emissions from these units are calculated and reported using the same methods as part 75.

Other units that are not in the ARP but report data under part 75, subpart C are now covered by 40 CFR part 98, subpart C instead of subpart D, and subpart C has been revised to allow the use of part 75 calculation methodologies. The response to the comment on these units is contained in Section III.C of this preamble (General Stationary Fuel Combustion Sources).

E. Adipic Acid Production

1. Summary of the Final Rule

Source Category Definition. The adipic acid production source category consists of all processes that use oxidation to produce adipic acid.

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 N_2O process emissions from adipic acid production.

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_2, N_2O, and CH_4 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. Unless an alternative method of determining N_2O emissions is requested, calculate N_2O process emissions from adipic acid production by multiplying a facility-specific emission factor by the annual adipic acid production level. Determine the facility-specific emission factor by an annual performance test to measure N_2O emissions from the waste gas stream of each oxidation process and the production rate recorded during the test.

When N_2O abatement devices (such as nonselective catalytic reduction) are used, adjust the N_2O process emissions for the amount of N_2O removed using the destruction efficiency for the control device and the fraction of annual production for which the control device is operating. The destruction efficiency 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 E.

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 E.

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 in this section or ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart E: Adipic Acid Production.''

- The re-testing trigger was changed. Performance testing to determine the N_2O emissions factor is required annually, whenever the ratio of cyclohexanone to cyclohexanol is changed, and when new abatement equipment is installed.
- Equation E–2 was edited to correct a calculation error and to allow multiple types of abatement technologies.
- 40 CFR 98.56 was reorganized and updated to improve the data reporting requirements as needed for the emissions verification process. Some data elements were moved from 40 CFR 98.57 to 40 CFR 98.56, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.53 were added to 40 CFR 98.56 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on adipic 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 E: Adipic Acid Production.''

GHGs To Report

Comment: Multiple commenters asked that the language in 40 CFR 98.52(b) be clarified to include emissions under 40 CFR part 98, subpart E only from units that are 100 percent dedicated to adipic acid production to avoid double counting of combustion emissions.

Response: We reviewed this issue but decided not to make any changes to 40 CFR part 98, subpart E. We do not foresee a potential for double counting of combustion emissions at the facility because all combustion unit emissions at adipic acid facilities are to be reported under 40 CFR part 98, subpart C. 40 CFR part 98, subpart E provides methods for reporting only the process N_2O emissions. Also see Section III.C of this preamble for responses to comments related to 40 CFR part 98, subpart C (General Stationary Combustion).

Selection of Proposed GHG Emissions Calculations and Monitoring Methods

Comment: One commenter stated that emissions of N_2O do not correlate with the production of adipic acid at their facility. A portion of the process off gas, which contains N_2O, is sold to an offsite facility via dedicated piping. The amount sold depends on customer needs and the amount is metered. The commenter asked that the language in the final rule address this issue.

Response: We agree that N_2O emitted from the production of adipic acid that is sold or transferred offsite is not covered in the proposed rule. The final rule has been changed to require this amount of N_2O to be reported. Allowing for this additional reporting requirement ensures that the reported N_2O emissions attributed to the adipic acid facility are accurate. Reporting of the N_2O sold or transferred offsite will help EPA improve methodologies for reporting of GHG emissions.

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 adipic acid production rate changed by more than 10 percent. Commenters asserted that production depends on demand for adipic acid and often varies by 15 percent.

Response: Upon review, we decided to eliminate re-testing. We believe that annual determination of the N_2O emissions factor is sufficient to accurately calculate N_2O emissions as long as the production equipment remains consistent over the year-long period (i.e. no new abatement technology).

Comment: Multiple commenters asked that alternative methods be allowed for calculating N_2O emissions from adipic acid production. Specifically the commenters asked that EPA allow the use of N_2O and flow CEMS to directly measure N_2O emissions and use the performance test to evaluate the CEMS accuracy. The commenters also asked that EPA allow the use of existing process flow meters and process N_2O analyzers to determine the amount of N_2O sent to control devices and use the performance test to measure control device destruction efficiency.

Response: We agree that there are other means of determining site-specific N_2O emissions. The final rule has been changed to allow alternative test 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. Until the method is approved facilities must use the alternatives proposed in the rule for a performance test. As one commenter noted, at minimum the performance test will help to QA/QC alternative methods currently used to monitor N_2O emissions (such as N_2O CEMS).

EPA understands the need to further evaluate and establish alternative comparable methods for sources to use in accurately calculating N_2O emissions from adipic production and will address in future rulemakings or amendments to rulemaking.

The final rule does allow the use of existing process flow meters and process knowledge in the determination of the destruction factor of N_2O abatement technologies. This parameter is often based on site-specific knowledge and operations. We believe that using existing methods can also reduce the potential cost impacts of this rulemaking and that it is in the best interest of the facilities that process parameters be accurately measured.

Comment: One commenter asked that Equation E–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 the commenter. 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.

F. Aluminum Production

1. Summary of the Final Rule

Source Category Definition. The aluminum production source category consists of facilities that manufacture primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process consists of the following operations:

- Electrolysis in prebake and Søderberg cells.
- Anode baking for prebake cells.

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 aluminum production, report:

- Perfluoromethane (CF_4) emissions and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electrolysis cells combined.
- CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg cells.
- All CO_2 emissions from anode baking.

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_2, N_2O, and CH_4 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 process emissions using the following methods:

- *CF_4 from anode effects:* Calculate annual CF_4 emissions based on the frequency and duration of anode effects in the aluminum electrolytic reduction process for each prebake and Søderberg electrolysis cell using the following parameters:

—Anode effect minutes (AEM) per cell-day calculated monthly.

—Aluminum metal production calculated monthly.

—A slope coefficient relating CF_4 emissions to anode effect minutes per cell-day and aluminum production. The slope coefficient is specific to each smelter and must be measured in accordance with the protocol specified in the rule at least once every 10 years.

—Facilities are allowed to use historic smelter-specific slope coefficients for the first three years of reporting under the rule. Historic measurements include all those made under EPA's Voluntary Aluminum Industry Partnership or at facilities owned or operated by companies participating in the Voluntary Aluminum Industry Partnership. Facilities without historic measurements are required to complete measurements by the end of first year of reporting.

—Facilities which operate at less than 0.2 anode effect minutes per cell day or, when overvoltage is recorded, operate with less than 1.4mV overvoltage, can use either smelter-specific measured slope coefficients or the technology-specific (Tier 2) default coefficients from Volume III, Chapter 4, Section 4.4 Metal Industry Emissions of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories as specified in the rule.

- *C_2F_6 from anode effects:* Calculate annual C_2F_6 emissions from anode effects from each prebake and Søderberg electrolysis cell using the calculated CF_4 emissions and the mass ratio of C_2F_6 to CF_4 emissions, as determined during the same test during which the slope coefficient is determined.
- *Process CO_2 emissions—general approaches.* Most reporters can elect to calculate and report process CO_2 emissions from anode consumption during electrolysis and from anode baking 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_2 emissions from anode consumption during electrolysis or anode baking 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_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack, instead of using the calculation procedures specified below.
- *CO_2 emissions from anode consumption in prebake cells:* Calculate annual CO_2 emissions at the facility level using a mass balance equation based on measurements of the following parameters:

—Net prebaked anode consumption rate per metric ton of aluminum metal produced.

—Ash and sulfur contents of the anodes.

—Total mass of aluminum metal produced per year for all prebake cells.

- *CO_2 emissions from Søderberg cells:* Calculate CO_2 emissions from paste consumption in Søderberg cells using a mass balance equation at the facility level based on the following parameters:

—Paste consumption rate per metric ton of aluminum metal produced and the total mass of aluminum metal produced per year for all Søderberg cells.

—Emissions of cyclohexane-soluble matter per metric ton of aluminum produced.

—Binder content of the anode paste.

—Sulfur, ash, and hydrogen contents of the coal tar pitch used as the binder in the anode paste.

—Sulfur and ash contents of the calcined coke used in the anode paste.

—Carbon in the skimmed dust from the cell, per metric ton of aluminum produced.

- *CO_2 emissions from anode baking of prebake cells:* Calculate CO_2 emissions at the facility level separately for pitch volatiles combustion and for bake furnace packing material.
- To calculate CO_2 emissions from the pitch volatiles, use a mass balance equation based on the following parameters:

—Initial weight of the green anodes.

—Mass of hydrogen in the green anodes.

—Mass of the baked anodes.

—Mass of waste tar collected.

- To calculate CO_2 emissions from bake furnace packing material, use a mass balance equation based on the following parameters:

—Packing coke consumption rate per metric ton of baked anode production.

—Sulfur and ash contents of the packing coke.

- The variables used to calculate CO_2 emissions from anode and paste consumption (e.g., sulfur, ash, and hydrogen contents) can be determined for each facility, or the source can use default values from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories as specified in 40 CFR 98.64.

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 F.

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 F.

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 F: Aluminum Production.''

- A new subsection was added in 40 CFR 98.63 providing a new equation (Eq. F–1) to sum monthly PFC emission values into annual PFC emission value.
- The equation for CO_2 emissions from Søderberg cells (paste consumption) was corrected.
- Language was updated to request reporting of all CO_2 emissions from on-site anode baking.
- Language was updated to request reporting of smelter-specific slope coefficient*s* (plural).
- A new equation was added in 40 CFR 98.63 (Eq. F–3) to calculate CF_4 emissions from overvoltage; and updated language in subsequent sections to accommodate the overvoltage method.
- Language was added to permit facilities that operate with low anode effect minutes or low overvoltages to use IPCC Tier 2 default slope factors.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Three comments on aluminum 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 F: Aluminum Production.''

Comment: Several commenters suggested that smelters should be permitted to use International Aluminum Institute default slope coefficients which are based on global technology-specific averages to calculate PFC emissions, especially at high performance facilities.

Response: The use of smelter-specific slope coefficients as required in the rule leads to significantly more precise PFC emission calculations than the use of default slope coefficients (95 percent confidence interval of ±15 compared to ±50 percent). For a typical U.S. smelter emitting 175,000 metric tons of CO_2-eq in PFCs, these errors result in absolute uncertainties of ±88,000 $MTCO_2e$ and ±26,000 $MTCO_2e$, respectively. The reduction in uncertainty associated with moving from default to smelter-specific slope coefficients, 62,000 $MTCO_2e$, is as large as the emissions from many of the sources that would be subject to the rule. However, for ''high performance'' facilities, which are defined by the 2006 IPCC Guidelines as those at or below 0.2 anode effect minutes per cell day or less than 1.4 mV overvoltage, the IPCC analysis indicates that impact of moving from a Tier 2 to a Tier 3 slope coefficient would not result in a significant improvement in PFC emissions. Therefore, EPA agrees that high performance facilities should be allowed to use technology specific (Tier 2) default values from Volume III, Chapter 4, Section 4.4 Metal Industry Emissions of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. These values are identical to the ''Aluminum Sector Greenhouse Gas Protocol (Addendum to the WRI/WBCSD Greenhouse Gas Protocol),'' October 2006 default coefficients.

Comment: Several commenters argued the requirement to re-measure smelter-specific slope coefficients every three years is expensive and unnecessary.

Response: While the cost to require smelter-specific slope coefficients is significantly greater than the cost to use default slope coefficients, the benefit of reduced uncertainty is considerable, as noted above. The costs that would be incurred by smelters measuring slope factors are discussed in the Regulatory Impact Analysis (RIA) for the proposed rulemaking (EPA–HQ–OAR–2008–0508–002).

Of the currently operating U.S. smelters, all but one has measured a smelter specific coefficient at least once; and at least three used the 2003 EPA/IAI protocol for measuring smelter-specific slope coefficients.

The *USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production* establishes guidelines to ensure that measurements of smelter-specific slope-coefficients are consistent and accurate (e.g., representative of typical smelter operating conditions and emission rates). The Protocol currently recommends that smelter operators re-measure their slope coefficients at least every three years, and more frequently if they adopt changes to process control algorithms or observe changes to typical anode effect duration. Specifically, the Protocol recommends that operators repeat measurements of slope coefficients for CF_4 and C_2F_6 if one or more of the following apply: (1) Thirty-six months have passed since the last measurements (i.e., triennial measurements are recommended); (2) a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; and, (3) changes occur in the distribution of duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects).

Changes to process control algorithms or to the typical duration of anode effects can change the relationship between anode effect minutes, production, and emissions, that is, they can change slope coefficients. In addition, more subtle changes can also change slope coefficients over time. According to industry experts, the rate of these more subtle changes has not been sufficiently studied to specify a frequency for re-measurement nor have there been a sufficient number of facilities that have been measured repeatedly to document the benefit of the additional incremental cost of measurement once every three years.

During the past few years, multiple U.S. smelters have adopted changes to their production process which are likely to have changed their slope coefficients. These include the adoption of slotted anodes and improvements to process control algorithms. Although some U.S. smelters have recently updated their measurements of smelter-specific coefficients, others may not have.

In view of these recent process changes, EPA is requiring smelters that have not already measured their slope factors under the ''2008 USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production,'' to do so in time for the 2013 reporting year. EPA believes that this will ensure that slope factors are appropriately updated while providing sufficient lead-time for smelters to perform the measurements without encountering excessive costs or logistical barriers. However, after this initial update, EPA agrees that every three years is burdensome, therefore, further updates are required only every ten years unless there are major technological or process changes at a facility such as changes to the control algorithm that affect the mix of types of anode effects or the nature of the anode effect termination routine; or changes occur in the distribution of duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects).

Comment: Several commenters suggested that the rule should include the overvoltage measurement method, which is specific to use with Pechiney technology, in case one or more U.S. smelters decide to adopt this technology in the future.

Response: The Overvoltage Method relates PFC emissions to an overvoltage coefficient, anode effect overvoltage, current efficiency, and aluminum production. The overvoltage method was developed for smelters using the Pechiney technology. While it is EPA's understanding that no U.S. smelters have used the Pechiney technology for at least a decade, if one or more U.S. smelters decide to adopt this internationally accepted technology in the future they would be expected to use the overvoltage method which follow the established guidelines in the ''USEPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production.''

G. Ammonia Manufacturing

1. Summary of the Final Rule

Source Category Definition. The ammonia manufacturing source category consists of process units in which ammonia is manufactured from a fossil-based feedstock via steam reforming of the hydrocarbon. It also includes ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

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 ammonia manufacturing, report the following emissions:

• CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements of this part.

• CO_2, CH_4, and N_2O emissions from each stationary combustion unit. Report these emissions under 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources) by following the requirements of 40 CFR part 98, subpart C.

• For CO_2 collected and transferred off site, report these emissions under 40 CFR part 98, subpart PP (Suppliers of CO_2) following the requirements of 40 CFR part 98, subpart PP.

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. Reporters must use one of two methods to calculate CO_2 process emissions, as appropriate:

• Most reporters can elect to calculate and report process CO_2 emissions from each ammonia manufacturing process unit 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 contained in the rule and summarized below.

• However, if process CO_2 emissions from an ammonia manufacturing process unit are emitted through the same stack as CO_2 emissions from a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined emissions from that stack, instead of using the calculation procedures described below.

• To calculate process CO_2 emissions, use the equations provided in 40 CFR part 98, subpart G for solid, liquid, and gaseous feedstock and the following measurements:

—Continuous measurement of gaseous or liquid feedstock consumed using a flowmeter, or monthly aggregate of solid feedstock consumed.

—Carbon content of the feedstock (required to be measured monthly using supplier data or analysis using the appropriate test methods). If supplier data are used, facilities must QA/QC the supplier analysis on an annual basis using the 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 G.

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 G.

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 G: Ammonia Manufacturing.''

• Monitoring and QA/QC requirements were revised to allow for obtaining carbon content of feedstock used in ammonia manufacturing from the feedstock supplier. Facilities that obtain monthly carbon content information from their supplier are required to QA/QC supplier information through annual sampling and analysis of the feedstock.

• Missing data procedures were added under 40 CFR 98.75 for parameters that facilities must measure such as feedstock consumption, the quantity of the waste recycle stream, and the monthly carbon content of both the feedstock consumption and waste recycle stream quantity.

• Reporting requirements were added for the quantity of urea produced and the emissions associated with waste recycle streams commonly found at ammonia manufacturing facilities.

• 40 CFR 98.76 was reorganized and updated to improve the emissions data verification process. Some data elements were moved from 40 CFR 98.77 to 40 CFR 98.76, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.73 were added to 40 CFR 98.76 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on ammonia manufacturing were received covering numerous topics. Several 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. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to

Public Comments, Subpart G: Ammonia Manufacturing.''

Method for Calculating GHG Emissions

Comment: Several commenters asked EPA to clarify that ammonia production units must use Tier 4 calculation only if all of the conditions under proposed 40 CFR 98.33(b)(5)(ii)(A) through (F) apply to the unit and only where the ammonia manufacturing unit already has installed a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

Response: We agree with the comment and have modified the text under 40 CFR 98.73(a) and (b) to state that if a facility operates and maintains CEMS that meet the requirements of 40 CFR 98.33(b)(4)(ii) or (iii), then process or combined process and combustion CO_2 emissions shall be calculated and reported under this subpart by following the Tier 4 Calculation Methodology specified in 40 CFR 98.33(a)(4) and all associated requirements for Tier 4 in 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). If CEMS are not used to determine CO_2 emissions from ammonia processing units, then facilities must calculate and report process CO_2 emissions under this subpart by using equations provided in 40 CFR 98.73(b)(1) through (b)(4). CO_2 combustion emissions from ammonia processing units must be reported under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). For additional clarification on the requirements on use of CEMS see 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), and Section III.C of this preamble.

Comment: One commenter noted that most ammonia facilities utilize natural gas combustion combined with approximately five percent recycle flow of gas containing methane from the process. The carbon content of the recycle stream is already accounted for when measuring the feedstock flow rate and carbon content to the process. EPA should allow ammonia manufacturers to exclude this recycle stream in calculating combustion emissions, as the carbon in the recycle stream would be double counted.

Response: We agreed with commenters that it is important to account for use of the waste process stream in the case that it is recycled since carbon in the recycle stream is not actually emitted. In response to this comment we have added reporting requirements for quantifying emissions associated with the recycle stream. This will help EPA improve methodologies for calculating emissions from ammonia manufacturing in the future.

Monitoring and QA/QC Requirements

Comment: Several commenters stated that monthly carbon content sampling and analysis requirement is overly burdensome. Some commenters asked that EPA allow the use of a default value for carbon content while one commenter suggested use of carbon content data generated by the feedstock supplier.

Response: We agreed with commenters that flexibility should be added to the rule to allow for use of supplier data. This information is readily available from the feedstock supplier in most cases. The most common feedstock for ammonia production is pipeline quality natural gas. Supplier data on carbon contents of feedstock will have sufficient or comparable accuracy for the purposes of calculating CO_2 emissions. We modified the monitoring and QA/QC procedures in the rule to allow use of carbon content data obtained from the feedstock supplier(s). Facilities that obtain monthly carbon content information from their supplier are required to QA/QC supplier information through annual sampling and analysis of the feedstocks consumed.

Procedures for Missing Data

Comment: Two commenters suggested that the proposed procedures for calculating emissions in the event of missing feedstock data would yield significant overstatements of GHG emissions. As proposed, if feedstock supply rate data are missing for a specific day or days (e.g., if a meter malfunctions during unit operation), the reporting entity must use the lesser of the maximum supply rate that the production unit is capable of processing or the maximum supply rate that the meter can measure. If this substitution is applied to the feedstock for reformers used in ammonia production, either of these proposed approaches would likely result in significant over reporting of carbon emissions. The commenter proposed two alternatives that a reporting facility could use: Either (1) substitute an estimated value for feedstock supply rate, based on the arithmetic average of the previous thirty days of available feedstock supply rate data; or (2) utilize missing data estimating procedures similar to the procedure under 40 CFR 98.35(b)(2), based upon all available process data. These approaches would result in much more accurate estimates of emissions derived from the true historical operation of a specific ammonia manufacturing source.

Response: We agreed with commenters that the proposed missing data procedures would overestimate emissions when applied. While some of feedstock should be readily available and collected as a part of normal business practices, circumstances could arise where data could be missing. We added procedures consistent with the commenter's second recommendation, referencing the missing data procedures in 98.35(b)(2). Ammonia facilities with missing data on feedstock supply rate must provide the best available estimate from all available process data. Facilities must document and keep records of missing data procedures applied. We find that these revised procedures will provide accurate information for the purposes of this rulemaking.

Data To Be Reported

Comment: One commenter noted that the CO_2 produced through ammonia manufacturing can be utilized and that much of it is in the manufacture of urea. The commenter stated that EPA makes unsubstantiated assumptions that all CO_2 in urea will be released into the atmosphere. The commenter asked EPA not to tie emissions from applied urea, or emissions that result from urea once the product has been sold, to the producing industry.

Response: We added reporting requirements for annual urea production under 40 CFR 98.76. Information on urea production will help us improve our understanding of the quantity of CO_2 consumed from ammonia production that is used in the manufacture of urea. We know from the US GHG inventory and subsequent conversations with ammonia producers that on average it takes 0.733 tons of CO_2 to produce one ton of urea. We have also requested that producers report, if known, the uses of the urea sold. Collecting information on urea production and its uses will help EPA to improve methodologies for calculating emissions from ammonia manufacturing, urea production, and urea consumption in the future.

H. Cement Production

1. Summary of the Final Rule

Source Category Definition. The cement production source category consists of each kiln and each inline kiln/raw mill at any Portland cement manufacturing facility, including alkali bypasses and kilns and inline kilns/raw mills that burn hazardous waste.

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 cement production, report the following emissions:

- CO_2 process emissions from calcination, reported for each kiln.
- CO_2 combustion emissions from each kiln.
- N_2O and CH_4 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_2, N_2O, and CH_4 emissions from each stationary combustion unit other than kilns under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- In addition, report GHG emissions for any other source categories for which calculation methods are provided in other subparts of the rule, as applicable.

GHG Emissions Calculation and Monitoring. For CO_2 emissions from kilns, reporters must select one of two methods, as appropriate:

- For kilns 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 measure and report under the Cement Production subpart (40 CFR part 98, subpart H) combined calcination and fuel combustion CO_2 emissions.
- For other kilns, the reporter can elect to either (1) install or operate a CEMS and follow the Tier 4 methodology to measure and report combined calcination and fuel combustion CO_2 emissions or (2) calculate process CO_2 emissions as the sum of clinker emissions and emissions from raw materials. If using approach (2):

—Calculate clinker emissions monthly from each kiln using monthly clinker production (required to be measured); a kiln-specific, monthly clinker emission factor calculated from the monthly CaO and MgO content of the clinker (required to be measured); quarterly cement kiln dust not recycled to the kiln (required to be measured); and a quarterly kiln-specific factor of calcined material in the cement kiln dust not recycled to the kiln (measured or default values can be used).

—Calculate raw material emissions annually from the annual consumption of raw materials and the organic carbon content in the raw material (measured annually for each type of raw material, or a default value of 0.2 percent may be used).

—Report process CO_2 emissions from each kiln under 40 CFR part 98, subpart H (Cement Production), and report combustion CO_2 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 H (Cement Production).

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 H (Cement Production).

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 H: Cement Production.''

- The CO_2 calculation equations in 40 CFR 98.83 were revised to account for non-carbonate sources of calcium and magnesium in the kiln feed and uncalcined carbonates in the product.
- Methods for monitoring CaO and MgO in clinker and CKD were changed from XRF to ASTM c114–07, Standard Test Methods for Chemical Analysis of Hydraulic Cement.
- 40 CFR 98.84 was revised to clarify required monitoring frequency and to allow for alternative monitoring methods for raw materials and CKD.
- Missing data procedures were added to 40 CFR 98.85 for parameters reporters must measure, clinker, CKD not recycled to the kiln, raw material consumption, carbonate contents of clinker CKD, non-calcined content of clinker and CKD, and organic carbon content of raw materials.
- Requirements in 40 CFR 98.81 through 40 CFR 98.87 were revised to clarify which requirements apply to reporters who elect to report CO_2 emissions using CEMS.
- 40 CFR 98.86 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.87 to 40 CFR 98.86, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.83 were added to 40 CFR 98.86 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. We received several comments on cement production covering a number of 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 dealing with that source category. *Also see* Section II.N of this preamble for the response to comments on the emissions verification approach.

Responses to significant comments received related to process emissions from cement production can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart H: Cement Production.''

Selection of Threshold

Comment: One commenter suggested that EPA could reduce the burden presented by the Proposed Rule by reducing the number of facilities required to report (i.e., raise the reporting thresholds). The commenter further noted that by requiring GHG reporting for all cement plants, regardless of the magnitude of the plant's emissions, EPA removes an incentive for those plants to reduce GHG emissions to get below a threshold in order to avoid the burden of monitoring and reporting.

Response: In considering the comment, we acknowledge the potential benefit of a reporting threshold providing cement plants with incentive to reduce their GHG emissions. 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. *See* Section II.H of this preamble for the response on provisions to cease reporting. *See* Section II.D of this preamble for the response on selection of source categories to report.

In developing the Proposed Rule, we considered emission-based thresholds of 1,000 metric tons CO_2e, 10,000 metric tons CO_2e, 25,000 metric tons CO_2e, and 100,000 metric tons CO_2e. All of these emission thresholds covered more than 99.9 percent of CO_2e emissions from cement facilities. Only one plant out of 107 in the dataset would be excluded by the highest considered thresholds of 100,000 metric tons CO_2e. Therefore, we determined that it was appropriate to include all cement production facilities in the reporting requirements.

Method for Calculating GHG Emissions

Comment: Two commenters stated that the cement industry already has an established, proven protocol for calculating and reporting GHG emissions, and requested that EPA use the existing Cement CO_2 Protocol as the basis for the Proposed Rule. Commenters further stated that the Cement CO_2 Protocol already provides many of the benefits that EPA ascribes to the Proposed Rule, including uniformity of reported data from one facility to another; availability of verifiable data to provide to the public, investors, and others; and other suggested benefits.

Both commenters stated that EPA needs to revise its clinker-based calculation to account for any non-carbonated CaO or MgO in the raw materials.

Response: In developing the proposed Rule, we considered many domestic and international GHG monitoring guidelines and protocols, including the Cement Sustainability Initiative Protocol referenced in the cement industry's comments. We combined elements of the Cement CO_2 Protocol with elements of other protocols including the 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), CARB mandatory GHG emissions reporting program, EPA's Climate Leaders program, and the EU Emissions Trading System to develop two proposed methods for quantifying GHG emissions from cement manufacturing. These proposed methods include the use of CEMS to directly measure emissions and the use of calculation methods to determine emissions.

While finalizing today's rule, we revisited the Cement CO_2 Protocol and compared its requirements to our requirements. We feel that the rule closely mirrors the GHG calculation methods and requirements of the Cement CO_2 Protocol with some minor differences. For example, our rule requires cement plants to use plant-specific emission factors to calculate CO_2 emissions and does not allow the use of default emission factors. As stated in the proposal, we have determined that applying default emission factors to clinker production is more appropriate for national-level emissions estimates than facility-specific estimates, where data are readily available to develop site-specific emission factors. Default approaches would not provide site-specific calculation of emissions that reflect differences in inputs, operating conditions, fuel combustion efficiency, variability in fuels, and other differences among facilities. Further, it is our understanding that facilities analyze data relevant for site-specific determinations such as the carbonate contents of their raw materials to the kiln and products on a frequent basis, either on a daily basis or every time there is a change in the raw material mix. Using data from direct measurements will provide a more accurate representation of site specific emissions rates.

We also note that the Cement CO_2 Protocol does not specify measurement methods. Our rule specifies methods for measuring CaO, MgO, and clinker weight. We selected these methods to be consistent with measurement techniques that are common within the cement industry. Prescribing standardized measurement procedures ensures the uniformity and consistency in the results and quality of data reported that the commenters agree is important for comparability of emissions.

We also used the Cement CO_2 Protocol as a model for revising our equations in 40 CFR 98.83 to account for non-carbonate sources of calcium and magnesium that may be present in the kiln feed.

Monitoring and QA/QC Requirements

Comment: One commenter expressed concern that 40 CFR 98.84(e) and (f) seem to require continuous, direct weight measurement of CKD discarded and raw materials used, by category of material. The commenter stated that most cement plants do not have that capability, and that the proposed rule does not clearly state whether installation of additional measurement equipment will be required if not already installed.

One industry representative further recommended that EPA add truck weight scales as an acceptable option for raw material weight measurement to address certain limited cases in which this method may be more appropriate to use. In addition, the commenter recommended that EPA allow CKD samples to be taken either as CKD exits the kiln or from bulk storage.

Response: We revised the text in 40 CFR 98.84(e) and (f) to more clearly state that CKD quantities are required to be measured on a quarterly basis and raw material quantities are required to be measured on a monthly basis. Furthermore, the Proposed Rule was never intended to require installation of new monitoring equipment for this purpose. We agree with the commenter that continuous, direct weight measurement of these materials and installation of additional measurement equipment would be unnecessary. The proposed rule clearly stated that the quantity of CKD produced and raw materials consumed must be determined using the same plant instruments that the cement plant currently uses for accounting purposes. Moreover, because the quantities of raw materials and CKD do not greatly impact the CO_2 calculation, we added further clarification to this section to allow cement plants to use potentially less accurate, but commonly used, methods of measurement, such as truck weigh scales, to determine quantities of CKD and raw materials. We also added clarification to 40 CFR 98.84 to allow facilities to collect CKD samples either as CKD exits the kiln or from bulk storage.

Data Reporting Requirements

Comment: Two commenters asserted that EPA needs to provide clarifying language within 40 CFR part 98, subpart H (Cement Production) to define which requirements apply to facilities using CEMS to monitor CO_2 emissions. One commenter noted that the Proposed Rule, as written, appears to require cement plants using CEMS to collect maintain, and report process data related to calculating CO_2 process emissions for kilns pursuant to proposed 40 CFR 98.84 through 98.87. This commenter claimed that requiring plants to collect and report such process data are redundant if the facility is continuously monitoring CO_2 emissions. Another commenter recommended that EPA state within 40 CFR part 98, subpart H (Cement Production) that all of the requirements detailed in the subpart do not apply to cement kilns using Tier 4 (CEMS) method.

Response: We agree with the comment that reporters who are using CEMS to monitor CO_2 do not need to collect, report, and maintain all of the process data required in proposed 40 CFR 98.84 through 98.87. However, we determined that some of the process data are necessary for emissions verification purposes, and therefore, plants using CEMS are not completely excluded from the requirements in 40 CFR part 98, subpart H (Cement Production). We added clarifying language throughout the Subpart to clearly state which requirements will apply to facilities that use CEMS to measure CO_2 emissions. Specifically, we created separate lists of reporting requirements and recordkeeping requirements for cement plants using CEMS.

Comment: One commenter noted that the data reporting requirements for cement plants, set forth in proposed 40 CFR 98.86, are expressed in different terms that those used for the specified procedures for calculating emissions. For example, the commenter stated that it is unclear what emission sources go into the ''site-specific emission factor (metric tons CO_2/metric ton clinker produced)'' required to be reported under proposed 40 CFR 98.86(h), and how that factor would be calculated.

Response: We agree with the commenter that there were inconsistencies between 40 CFR 98.83 and 98.86. We updated reporting requirements in 40 CFR 98.86 to be consistent with the terms used in the emission calculation procedures in 40 CFR 98.83 and provide clarification in 40 CFR 98.83 for terms if needed. As a result, some calculations that are performed on a kiln-specific basis, such as CO_2 emission factors, will be required to be reported on a kiln-specific basis in 40 CFR 98.86. Also see the Section II.N of this preamble for the response to comments on the emissions verification approach.

I. Electronics Manufacturing

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

The Agency received a number of lengthy, detailed comments regarding the electronics manufacturing subpart. Commenters generally opposed the proposed reporting requirements and stated the proposal required excessive detail. For example, commenters asserted that they currently do not collect the data required to report using an IPCC Tier 3 approach and that to collect such data would entail significant burden and capital costs. In most cases, commenters provided alternative approaches to each of the reporting requirements proposed by EPA.

Commenters also requested clarification from EPA on a number of the proposed reporting provisions.

Based on careful review of comments received on the proposal preamble, rule, and technical support documents (TSDs) under proposed 40 CFR part 98, subpart I, 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.

J. Ethanol Production

At this time, EPA is not finalizing the Ethanol Production Subpart. The sources of GHG emissions at ethanol production facilities that were to be reported under the proposed rule were stationary fuel combustion, onsite landfills, and onsite wastewater treatment. EPA has decided not to finalize the portion of 40 CFR part 98, subpart HH (Landfills) that addresses industrial landfills nor 40 CFR part 98, subpart II (Wastewater Treatment). Stationary fuel combustion sources at ethanol production facilities are subject to the requirements of 40 CFR part 98, subpart C if general stationary fuel combustion emissions exceed the 25,000 metric tons CO_2e threshold.

As EPA considers next steps, we will be reviewing the public comments and other relevant information. Based on careful review of comments received on the proposal preamble, rule and TSDs under proposed 40 CFR part 98, subparts J, HH, and II, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies contained in those subparts.

K. Ferroalloy Production

1. Summary of the Final Rule

Source Category Definition. The ferroalloy production source category consists of facilities that use pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

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 ferroalloy production, report the following emissions.

• Annual process CO_2 emissions from each EAF used for production of any ferroalloy listed in the source category definition.

• Annual process CH_4 emissions for those EAFs used for the production of silicon metal, ferrosilicon 65 percent, ferrosilicon 75 percent, or ferrosilicon 90 percent.

• CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

• In addition, report emissions from any other source categories for which calculation methodologies are specified in the rule, as applicable.

GHG Emissions Calculation and Monitoring. To calculate process CO_2 emissions from EAFs, reporters can use one of two methods, as appropriate:

• Most reporters can elect to calculate and report process CO_2 emissions from each EAF by either (1) installing and operating a CEMS and following the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) using the carbon mass balance calculation procedure specified in the rule and summarized below.

• However, if CO_2 process emissions from an EAF are emitted through the same stack as CO_2 emissions from a combustion unit or process equipment that uses a CEMS and follows Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined emissions from that stack, instead of using the carbon mass balance calculation procedure described below.

• If using the carbon mass balance procedure, perform a once per year calculation using equations in the rule and:

—Recorded monthly production data, and
—The average carbon content for each EAF input and output material determined by either using material supplier information or by annual analysis of representative samples of the material.

• For those EAF's for which the reporter must report annual CH_4 emissions, annual ferroalloy production data are used with an applicable emissions 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 K.

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 K.

2. Summary of Major Changes Since Proposal

The major changes to the rule since proposal for ferroalloy production facilities were revisions to the carbon mass balance calculation procedure for calculating process CO_2 emissions from EAFs. These changes reduce the reporting burden and are consistent with revisions made to other similar industries. 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 K: Ferroalloy Production.''

- Frequency of performing the carbon mass balance calculations was revised to be required on an annual basis instead of the proposed monthly basis.
- Frequency of material carbon content sampling and analysis of each EAF input and output material used for the material balance was revised to be performed by annual analysis of representative samples of the material instead of the proposed monthly basis.
- Materials contributing less than one percent of the total carbon into or out of the EAF do not need to be included carbon mass balance calculations.
- 40 CFR 98.116 and 98.117 were reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.117 to 40 CFR 98.116, 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 98.116 for clarity. See Section II.N of this preamble for the response to comments on the emissions verification approach.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Other comments on ferroalloy production were received covering various topics. Responses to significant comments received can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart K: Ferroalloy Production.''

Comment: One comment was received on the proposed rule specific to ferroalloy production facilities. The commenter requested that EPA allow ferroalloy production facilities to use alternative methods for determining EAF process CO_2 emissions other than those proposed, and specifically a protocol for silicon metal production facilities developed for use by the Chicago Climate Exchange. This smelting protocol was developed a protocol for calculating the CO_2 emissions from based on the World Resources Institute (WRI) aluminum smelting protocol.

Response: We reviewed the WRI aluminum smelting protocol, which was publicly available and we tried to obtain a copy of the specific protocol that the commenter mentions to fully evaluate whether it is an appropriate alternative. However, we never received it in the long run. The commenter did not provide additional or more specific recommendations beyond the reference to improve or revise the proposed methodology. At this time, given insufficient information, we have decided not to include additional alternative methods in the final rule for ferroalloy production facilities. As we stated at proposal, the selected methodology was based on review of several existing methodologies used by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Canadian Mandatory Greenhouse Gas Reporting Program, the Australian National Greenhouse Gas Reporting Program, and EU Emissions Trading System.

However, we have revised the frequency of sampling and analysis of carbon contents for carbon containing input and output materials monthly to annual consistent with revisions made in response to comments for similar production processes (e.g. emissions from metal production). These revisions reduce the reporting burden for ferroalloy production facilities. We understand that the carbon content of material inputs and outputs 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. The response to the comment can be found in ''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart K: Ferroalloy Production.''

L. Fluorinated GHG Production

At this time EPA is not going final with the subpart for emissions from fluorinated GHG production. As we consider next steps, we will be reviewing the public comments and other relevant information.

The Agency received a number of lengthy, detailed comments regarding the fluorinated GHG production subpart. Commenters generally opposed the proposed reporting requirements. Several commenters stated that facilities could not meet the proposed accuracy, precision, and frequency requirements 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. Some commenters stated that even after such equipment was installed, the proposed mass-balance approach was likely to be inaccurate, particularly for batch processes. In most cases, commenters provided alternative approaches, such as emission-factor based approaches, to the proposed mass-balance approach.

Based on careful review of comments received on the proposal preamble, rule, and TSDs under proposed 40 CFR part 98, subpart L, 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.

M. Food Processing

At this time, EPA is not going final with the Food Processing Subpart. The sources of GHG emissions at food processing facilities that were to be reported under the proposed rule were stationary fuel combustion, onsite landfills, and onsite wastewater treatment. EPA has decided not to finalize the portion of 40 CFR part 98, subpart HH (Landfills) that addresses industrial landfills nor 40 CFR part 98, subpart II (Wastewater Treatment). Note, however, that Stationary fuel combustion sources at food processing facilities are subject to the requirements of 40 CFR part 98, subpart C if general stationary fuel combustion emissions exceed the 25,000 metric ton CO_2e threshold. As EPA considers next steps, we will be reviewing the public comments and other relevant information.

Based on careful review of comments received on the proposal preamble, rule and TSDs under proposed 40 CFR part 98, subparts M, HH, and II, EPA will perform additional analysis and consider alternatives to data collection procedures and methodologies contained in those subparts.

N. Glass Production

1. Summary of the Final Rule

Source Category Definition. The glass production source category consists of facilities that manufacture glass (including flat, container, pressed, or blown glass) or wool fiberglass using one or more continuous glass melting furnaces. Experimental furnaces and research and development process units are excluded.

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 glass production facilities, report the following emissions:

- CO_2 process emissions from each continuous glass melting furnace.
- CO_2 combustion emissions from each continuous glass melting furnace,
- CH_4 and N_2O emissions from fuel combustion at each continuous glass melting furnace under 40 CFR part 98, subpart C (General Stationary Combustion Sources) using the methodologies in subpart C.
- CO_2, CH_4, and N_2O emissions and from each onsite stationary fuel combustion unit other than continuous glass melting furnaces under 40 CFR part 98, subpart C (General Stationary 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_2 process emissions from glass melting furnaces, reporters must use one of two methods, as appropriate:

- For glass melting furnaces 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 measure and report under the glass production subpart (40 CFR part 98, subpart N) combined process and combustion CO_2 emissions.
- For other glass melting 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_2 emissions or (2) calculate process CO_2 emissions for each furnace using an emission factor and process data. If using approach (2), multiply a default emission factor appropriate for the carbonate raw material by:

—The annual mass of carbonate-based raw material charged to the furnace (required to be measured); and

—The mass-fraction of carbonate in the raw material (based on data supplied by the raw material supplier and verified by an annual measurement).

—Under approach (2), report process CO_2 emissions from each glass melting furnace under 40 CFR part 98, subpart N (Glass Production), and report combustion CO_2 emissions from each glass furnace 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 N.

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 N.

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 N: Glass Production.''

- The definition of the term ''glass produced'' was added to the definitions in 40 CFR part 98, subpart A.
- 40 CFR 98.146 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.147 to 40 CFR 98.146, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.143 were added to 40 CFR 98.146 for clarity.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. Several comments on glass 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 N: Glass Production.''

Definition of Source Category

Comment: One commenter stated that EPA should exempt from the rule all fiber glass and rock and slag wool insulation facilities within the glass production source category because glass production facilities subject to the proposed rule are a miniscule portion of the total national emissions of CO_2e, and amount to less than 0.1 percent of total GHG emissions in the U.S. and the subset of fiber glass and rock and slag wool insulation facilities is an even smaller portion. The commenter stated that there is virtually no benefit to having the glass production source category subject to the proposed rule, and any benefit is outweighed by the burden imposed on these facilities. The commenter also pointed out the importance of the fiber glass and rock and slag wool insulation industry's products in meeting the nation's energy needs and reducing GHG emissions. Exempting the industry from the proposed rule's reporting requirements will help the industry focus more of its scarce resources on producing insulation.

Response: We recognize that the glass manufacturing industry is comprised of a wide range of facilities, many of which are small in size and have relatively low levels of emissions. However, the data we have collected on the industry indicate that there are several large glass manufacturing plants with significant GHG emissions. These plants include some that produce glass fiber, flat glass, and container glass, as well as other types of pressed and blown glass products. As a result, we do not agree with the commenter that fiber glass and other types of insulation facilities should be exempt from reporting. However, we tried to reduce the burden on the glass manufacturing industry by incorporating into the proposed rule a 25,000 metric ton CO_2e threshold, which should preclude small facilities from having to report GHGs. This threshold remains in the final rule. Thus, any small fiber glass and rock and slag wool insulation facilities with low GHG emissions will fall under the threshold and will be exempt from reporting. To further minimize the burden on the industry, we have tried to limit recordkeeping and reporting requirements to the types of data that glass production facilities already collect as part of normal business operations.

Commenters may also be interested in reviewing Section II.H of this preamble for the response on provisions to cease reporting. The final rule contains provisions to cease reporting if annual reports demonstrate emissions less than specified levels for multiple years.

Selection of Threshold

Comment: One commenter remarked that EPA should raise the threshold for reporting for fiberglass and rock and slag wool insulation entities. Doing so would reduce the number of entities reporting with only a minimal impact on the amount of emissions covered. The commenter stated that EPA's analysis did not address reasonable alternative thresholds between 25,000 and 100,000 metric tons.

Response: When evaluating potential thresholds for reporting GHG emissions, we considered several thresholds between 1,000 and 100,000 metric tons CO_2e. We selected the 25,000 metric tons CO_2e threshold for reporting GHG emissions in order to achieve a balance between quantifying the majority of the emissions and minimizing the number of facilities impacted. For example, at a 1,000 metric tons CO_2e threshold, 98 percent of emissions would be covered, with about 58 percent of facilities being required to report. Compared to the 100,000 metric tons CO_2e threshold, the proposed 25,000 metric tons CO_2e threshold achieves reporting of 11 times more emissions while requiring less than 15 percent of the facilities to report. Compared to the 10,000 metric tons CO_2e threshold, the 25,000 metric tons CO_2e threshold captures more than half of those emissions, but only requires a third of the facilities in the industry to report. This threshold offers significant coverage of the GHG emissions while impacting a relatively small portion of the industry. Although a threshold of 50,000 metric tons CO_2e would greatly reduce the number of facilities reporting, it would capture less than 20 percent of total emissions for the industry. We believe the proposed threshold of 25,000 metric tons CO_2e represents the best option for ensuring that the majority of emissions are reported without imposing an unreasonable burden on the industry.

Section II.E of this preamble contains a general discussion of the selection of the 25,000 metric tons CO_2e threshold.

Method for Calculating GHG Emissions

Comment: One commenter fully supports EPA's proposed rule for measuring, calculating, monitoring, and reporting emissions from the glass melting process. They agree that 40 CFR part 98, subpart N represents a good balance between site reporting burden, cost, and data accuracy and consistency. Specifically, the commenter supports using raw-material emissions factors and usage rates, as proposed, to calculate emissions from glass production in lieu of requiring installing CEMs on sources that another regulation does not currently require to be installed.

Response: We acknowledge this support for the proposal and appreciate these comments. We have retained the proposed calculation methodology in the final rule.

Data Reporting Requirements

Comment: One commenter stated that, at various places in the preamble and proposed rule, EPA uses the phrase ''glass produced,'' but has not defined this phrase in the rule. The commenter noted that the phrase could be interpreted to mean either glass melted or glass product produced. The commenter assumed that the phrase refers to the amount of glass melted, but requested clarification.

Response: We agree that the term glass produced is subject to interpretation. We have added a definition of the term to 40 CFR part 98, subpart A of the final rule. ''Glass produced'' means the weight of glass exiting a glass melting furnace.

Comment: One commenter remarked that some of the information that would have to be reported under the proposed rule, such as annual quantity of glass produced, is considered to be company confidential and could be used by competitors to back-calculate product formulas. The commenter requested that EPA remove these reporting requirements from the rule and instead, require that the data be retained by the facility and made available for review by EPA. Should EPA require the reporting of all of this information in the final rule, the commenter requests that EPA explicitly state in the final rule and confirm in the preamble to the final rule that all information provided under 40 CFR part 98, subpart N, other than the annual process emissions of CO_2, is considered confidential information and would not be considered ''emission data'' under this reporting rule. The commenter requests that a new paragraph (e) be added to 40 CFR 98.146 that reads: ''No information required to be reported by this section, other than the information required by 40 CFR 98.146(a), is considered to be emission data under 40 CFR 2.301(a)(2)(i) and (ii).''

Response: We acknowledge the commenter's concerns. However, the quantity of glass produced is an important variable for EPA to verify whether reported emissions are within a reasonable range and therefore is a required reporting parameter under 40 CFR part 98, subpart N.

We have 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.''

O. HCFC–22 Production and HFC–23 Destruction

1. Summary of the Final Rule

Source Category Definition. This source category consists of:

• Processes that produce HCFC–22 (chlorodifluoromethane or $CHClF_2$) using chloroform and hydrogen fluoride.

• HFC–23 destruction processes located at HCFC–22 production facilities.

• HFC–23 destruction processes that destroy more than 2.14 metric tons of HFC–23 per year and that are not located at HCFC–22 production 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 facilities that produce HCFC–22 or that destroy HFC–23, report the following emissions:

• HFC–23 emissions from all HCFC–22 production processes at the facility.

• HFC–23 emissions from each destruction process.

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_2, N_2O, and CH_4 emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Reporters must calculate HFC–23 emissions as follows:

• For HCFC–22 production processes that do not use a thermal oxidizer or that have a thermal oxidizer that is not connected to the production equipment, calculate annual HFC–23 emissions at the facility level using a mass balance equation and the following information: annual HFC–23 generated, the annual HFC–23 sent off site for sale, the annual HFC–23 sent off site for destruction, the annual increase in the HFC–23 inventory, and the annual HFC–23 destroyed on site (calculated by multiplying the mass of HFC–23 fed to the destruction device by the destruction efficiency).

• For HCFC–22 production processes with a thermal oxidizer that is connected to the production equipment, calculate annual HFC–23 emissions at the facility level by summing the following emissions:

—Annual HFC–23 emissions from equipment leaks (calculated using default emission factors and the measured number of leaks in valves, pump seals, compressor seals, pressure relief valves, connectors, and open-ended lines).

—Annual HFC–23 emissions from process vents (calculated for each vent using the HFC–23 emission rate from the most recent emission test and the ratio of the actual production rate and the production rate during the emission test).

—Annual HFC–23 from the thermal oxidizer (calculated by subtracting the amount of HFC–23 destroyed by the destruction device from the measured mass of HFC–23 fed to the destruction device).

- For other HFC–23 destruction processes, calculate HFC–23 emissions based on the mass of HFC–23 fed to the destruction device and the destruction efficiency.
- For the destruction efficiency, conduct a performance test or use the destruction efficiency determined during a previous performance test. To confirm the destruction efficiency, measure the fluorinated GHG concentration at the outlet to the destruction device annually.

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 O.

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 O.

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 O: HCFC–22 Production and HFC–23 Destruction.''

- The minimum required frequency of mass flow and concentration measurements has been decreased from daily to weekly.
- The required frequency of emissions tests at process vents has been decreased to once every five years. A test is also required after a significant change is made to the process.
- The required annual measurements at the outlet of the thermal oxidizer now omit measurements of mass flow. Three samples are required to be taken; the average of these is compared to the concentration at the outlet of the oxidizer that was measured during the initial performance test that established the destruction efficiency.
- A term has been added to the mass-balance equation for HCFC–22 production facilities that do not have a thermal oxidizer that is directly connected to the HCFC–22 production equipment. This term accounts for increases in the inventory of stored HFC–23 that can occur during the year.
- EPA has added an additional method for estimating missing mass flow data in the event that a secondary mass measurement for that stream is not available.
- 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 has been removed.
- Some reporting requirements have been added to be consistent with the changes to the calculations and monitoring sections and to permit verification of emissions calculations.

EPA decreased the minimum frequency of gas flow and concentration measurements from daily to weekly because EPA's research indicates that HFC–23 concentrations are not likely to vary significantly over a one week period. This change also makes the required measurement frequency more consistent with current industry practice.

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 number of comments on HCFC–22 production and HFC–23 destruction 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 O: HCFC–22 Production and HFC–23 Destruction.''

Monitoring and QA/QC Requirements

Comment: EPA received a comment that the requirement to annually conduct emissions tests at process vents is overly burdensome and unnecessary because it is unlikely that the emissions rate would deviate from an initial process vent test unless there were a significant change in the process. This commenter argued that testing should be required at least every five years or after a significant change in the process.

Response: In response to this comment, EPA has reduced the required frequency of emissions tests at process vents to once every five years, or after a significant change to the process. EPA has also clarified that the requirement applies only to HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment. These are the only facilities that use process vent emission estimates in their calculation of facility-wide HFC–23 emissions.

EPA is decreasing the frequency of emissions tests at process vents for two reasons. First, EPA agrees with the commenter that, in the absence of a significant process change, the process vent emission rate is not likely to vary much (in percentage terms) from year to year. Second, although small variations in the emission rate could still lead to significant absolute errors for facilities with large process vent emissions, the facilities that are required to test their process vent emissions are likely to have small process vent emissions (because they use thermal oxidizers connected to the production equipment). (Facilities that do not use thermal oxidizers connected to the equipment would be expected to have larger process vent emissions, but they are required to use a mass-balance approach to calculate emissions rather than summing emissions across process vents, equipment leaks, and thermal oxidizers.) Together, these considerations lead to the conclusion that testing process vent emissions every five years should sufficiently minimize errors in the overall HFC–23 emission calculations of the facilities affected by the testing requirement.

Comment: EPA should add a term to Equation O–4 (the mass-balance equation for HCFC–22 production facilities that do not have a thermal oxidizer that is directly connected to the HCFC–22 production equipment) to account for increases in the inventory of stored HFC–23 that can occur during the year.

Response: EPA added a term to Equation O–4 for increases in the inventory of stored HFC–23. EPA agrees that the equation should account for changes in the inventory of HFC–23 that is stored on site. It is important to track all reservoirs of HFC–23 at the facility; mass-balance approaches used to track emissions from other sources (e.g., from electrical equipment) frequently include terms to account for the increase in inventory.

Definition of Source Category

Comment: EPA received a comment that the measurement of HFC–23 emissions from HCFC–22 production should be moved to Subpart L, which covers the reporting of fluorinated GHG production.

Response: EPA proposed provisions for facilities producing fluorinated gases in three separate subparts: 40 CFR part 98, Subpart L, Subpart O, and Subpart OO. Although there are many similarities across the chemicals and processes covered by the three subparts, the subparts were deliberately tailored to different sources and types of emissions. Subpart L was intended to address emissions of fluorinated GHGs from fluorinated GHG production. 40 CFR part 98, subpart O was intended to address HFC–23 generation and emissions from HCFC–22 production. 40 CFR part 98, subpart OO was intended to address flows affecting the U.S. industrial gas supply, including production, transformation, and destruction.

EPA determined that 40 CFR part 98, subpart O was necessary because HCFC–22 production and HFC–23 destruction facilities differ from other fluorinated gas production facilities in two key respects. First, the primary fluorinated GHG that they generate (HFC–23) is made as a byproduct to the production of a substance that is not defined as a fluorinated GHG (HCFC–22). Second, due to the very high GWP of HFC–23, each HCFC–22 facility generates very large quantities of CO_2-equivalent. For the second reason, EPA has worked with HCFC–22 producers for over ten years to understand and reduce HFC–23 emissions. The requirements for HCFC–22 producers are therefore based on a close knowledge of their production processes and methods for accounting for emissions. These methods are also comprehensive (e.g., accounting for emissions from equipment leaks and losses during transport of HFC–23 that is shipped off-site for destruction). These requirements may not be appropriate for other fluorinated gas producers, and, at the same time, the requirements for fluorinated gas producers may not be appropriate for HCFC–22 producers.

P. Hydrogen Production

1. Summary of the Final Rule

Source Category Definition. The merchant hydrogen production source consists of process units that produce hydrogen by reforming, gasification, or other transformation of feedstock and transfer the hydrogen produced off site. Hydrogen production facilities located at petroleum refineries or other large facilities are included in this source category only if they are not owned by or under the direct control of the refinery owner. Otherwise, they are considered to be a captive hydrogen production source that reports emissions under the subpart applicable to the larger facility, e.g., 40 CFR part 98, subpart Y (Petroleum Refineries).

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 hydrogen production, report the following emissions:

• CO_2 process emissions from hydrogen production.

• CO_2, N_2O, and CH_4 emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

• CO_2 collected and transferred off site under 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide).

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

GHG Emissions Calculation and Monitoring.

• To calculate and report process CO_2 emissions from hydrogen production, most reporters can elect to either (1) install and operate CEMS and follow the Tier 4 methodology (in 40 CFR part 98, subpart C) or (2) calculate process CO_2 emissions using equations in the 40 CFR part 98, subpart P and the following data:

—Measurements of monthly feedstocks and fuel consumed.

—Carbon content of the feedstock measured monthly.

—Molecular weight of the feedstock (gaseous fuels only).

• However, if process CO_2 emissions from hydrogen production are vented through the same stack as a combustion unit or process equipment that uses a CEMS to follow Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack instead of the calculation procedure described in approach 2 above.

Monitoring and QA/QC Requirements. The methods for the initial calibration and annual recalibration of flow meters are defined in a prescriptive list of industry standard test methods incorporated by reference in the Tier 3 method in 40 CFR part 98, subpart C, while the methods for determining carbon content of fuels and feedstocks are defined in a prescriptive list of an assortment of industry standard test methods incorporated by reference.

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 P.

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 P.

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 P: Hydrogen Prodution.''

• 40 CFR 98.160 was reworded to clarify the definition of reporting entity.

• 40 CFR 98.162 was revised to allow reporting of combined process and combustion CO_2, CH_4, and N_2O emissions.

• In 40 CFR 98.163(b), ''feedstock'' was changed to ''fuel and feedstock''.

• 40 CFR 98.164 was restructured to clarify between CEMS measurements and QA/QC and feedstock method measurements and QA/QC.

• 40 CFR 98.164 was reworded 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 to allow liquid and solid hydrocarbon fuels of commerce to be characterized upon delivery if delivered by bulk transport.

- The recalibration requirements in 40 CFR 98.164 were changed to reduce economic impact.
- The list of standards incorporated by reference in 40 CFR 98.164 was broadened.
- The missing data procedures in 40 CFR 98.165 were revised to be consistent with 40 CFR 98.35(b).
- 40 CFR 98.166 and 98.167 were restructured to distinguish between CEMS recordkeeping and feedstock method recordkeeping.
- 40 CFR 98.166 was reorganized and updated to improve the emissions verification process. Some data elements were moved from 40 CFR 98.167 to 40 CFR 98.166, and some data elements that a reporter must already use to calculate GHGs as specified in 40 CFR 98.163 were added to 40 CFR 98.166 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 hydrogen 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 P: Hydrogen Production.''

Definition of Source Category

Comment: Multiple commenters pointed out the lack of clarity regarding the definition of the reporting entity, and suggested defining the entity holding the air permit for an affected facility as the reporting entity. For example, ''If the owner/operator of the facility is the holder of the air permit for an affected facility, then the operator should be responsible for reporting GHG emissions. If not, then EPA should clarify the responsibility for reporting.''

Response: EPA reviewed this complex issue. First, a facility is defined in 40 CFR 98.6: ''*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.'' Therefore, any hydrogen production process unit that is not part of a larger facility covered by another subpart of this rule is a merchant hydrogen production facility which reports emissions under 40 CFR part 98, subpart P. On the other hand, a hydrogen production process unit that is part of a larger facility covered by another subpart of this rule is a captive hydrogen production facility that does not report emissions under 40 CFR part 98, subpart P. Their emissions, including those emissions from the captive hydrogen production facility, are reported under the subpart applicable to the larger facility. Second, in answer to the question, ''Do I need to report?'', 40 CFR 98.2 states that the rule applies to a facility that contains any source category listed in 40 CFR 98.2(a)(2) (which includes hydrogen production) and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonates, and all source categories listed in 40 CFR 98.2(a)(2). EPA has concluded that the rule explains this clearly in 40 CFR 98.2 and 98.6, and that it is not necessary to change the rule. To add clarity, however, EPA has revised 40 CFR 98.160(c) as follows: ''This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.''

GHGs To Report

Comment: Multiple commenters requested clarification on the CO_2 emission reporting obligation as combined ''process'' and ''combustion'' CO_2 emissions, regardless of the calculation method employed. If separate, discrete reporting of such emissions is actually required, commenters asked EPA to provide explicit protection for this information which they stated was very critical CBI.

Response: In response to these multiple commenters, EPA has clarified the rule in 40 CFR 98.162 to provide operators the option of providing combined process and combustion CO_2 emissions for each hydrogen production process unit whether or not it meets the conditions in 40 CFR 98.33(b)(4)(ii) and (iii) for CEMs. Under 40 CFR 98.166, facilities must report additional parameters for emissions verification.

See Sections II.I and II.N of this preamble for responses to the comments received on the general content of the annual GHG report and the emissions verification approach, respectively. 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.''

Method for Calculating GHG Emissions

Comment: Multiple commenters pointed out the need for a calculation method to account for feedstock carbon that does not exit the hydrogen production facility as CO_2, but rather in the form of other products or co-products that contain carbon (such as synthesis gas, CO, CH_4). Many argued in favor of correcting equations P–1, P–2 and P–3 to account for feedstock carbon that does not exit the hydrogen production facility as CO_2, but rather as products (such as synthesis gas, CO, CH_4) that are manufactured which contain carbon.

Response: EPA generally concurs with the need to account for ''carbon other than CO_2'' that exits the facility. EPA considered several options for reporting such carbon and chose to have facilities report CO_2 and ''carbon other than CO_2'' as separate data reporting elements in 40 CFR 98.166 rather than including this carbon in equations P–1, P–2, and P–3. As a result, EPA has added data reporting elements under 40 CFR 98.166 for (1) quarterly quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons), following the requirements of 40 CFR part 98, subpart PP of this part, and (2) annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons).

Monitoring and QA/QC Requirements

Comment: Multiple commenters recommended that EPA should allow the characterization of feedstocks (sampling and analysis) to be conducted by either the feedstock consumer (the regulated source) or the feedstock supplier. They state that the characterization of standard fuels of commerce used as hydrogen production feedstocks, such as natural gas, should not be required since default values will yield a sufficiently accurate emission estimate. Commenters recommend that characterization of such standard fuels of commerce used as feedstocks be optional, at the source's discretion.

Response: EPA concurs with this comment, since feedstock suppliers regularly monitor the carbon content of their fuels and also, the carbon content of standard fuels of commerce are quite consistent month to month. 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). 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_2 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_2, CH_4, and N_2O 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_2 emissions from flares according to the requirements in 40 CFR part 98, subpart Y (Petroleum Refineries) and CH_4 and N_2O emissions from flares using the default emission factors for coke oven gas and blast furnace gas.
- CO_2 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_2 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_2 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_2 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_2 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_2 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_2 emissions from a combustion unit or process equipment that uses a CEMS and follows the Tier 4 methodology to report CO_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the other process CO_2 calculation approaches outlined above.
- For coke oven pushing, facilities must use a CO_2 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_2 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_2 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_2. 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_2 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 ±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_2 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_2 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_2 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_2 emissions by 20 percent or more.

We disagree that annual re-testing is excessive because testing for CO_2 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_4 and N_2O emissions do not have to be reported for iron and steel production processes, and other commenters requested that CH_4 and N_2O emissions reporting not be required for the combustion of coke oven gas and blast furnace gas. Commenters noted that default emission factors for CO_2, CH_4, and N_2O 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_4 and N_2O 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_2 and N_2O for these process gases to the tables in 40 CFR part 98, subpart C, and we developed new emission factors for CH_4 based on the typical CH_4 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_2 process emissions from each smelting furnace used for lead production.
- CO_2 combustion emissions from each smelting furnace used for lead production.
- N_2O and CH_4 emissions from each smelting furnace under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) using the methodologies in subpart C.
- CO_2, N_2O, and CH_4 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_2 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_2 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_2 emissions or (2) calculate annual process CO_2 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_2 emissions from each smelting furnace under 40 CFR part 98, subpart H (Cement Production), and report combustion CO_2 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_2 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 results 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_2e and only lead production facilities with emissions that equal or exceed 25,000 metric tons CO_2e 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_2e. We selected the 25,000 metric tons CO_2e 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_2e threshold, 99 percent of emissions would be covered, with about 63 percent of facilities being required to report. The 100,000 metric tons CO_2e threshold captures no emissions or facilities while the proposed 25,000 metric tons CO_2e 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_2e 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_2 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_2 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_2 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_2 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_2 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_2 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 cacareous 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_2 process emissions from all lime kilns combined.
- CO_2 combustion emissions from lime kilns.
- N_2O and CH_4 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_2, N_2O, and CH_4 emissions from each stationary combustion unit other than kilns under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).
- CO_2 collected and transferred off site under 40 CFR part 98, subpart PP (Suppliers of CO_2).

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_2 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_2 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_2 emissions from all lime kilns or (2) calculate CO_2 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_2 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_2 emissions from all kilns combined under 40 CFR part 98, subpart S (Lime Manufacturing), and report combustion CO_2 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_2, CH_4, and N_2O 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_2 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_2 emissions generated for each type of lime produced. Therefore these data are required in order to verify the CO_2 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_6 will provide at least a general, order-of-magnitude check on consumption of SF_6 by magnesium production and other uses of SF_6. 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_2 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_2 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_2 process emissions for all miscellaneous uses of carbonates as specified in this subpart.
- CO_2, N_2O, and CH_4 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_2 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_2 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_2 emissions, such as adding sodium carbonate to a water softener system. Acid-induced releases of CO_2 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_2 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_2 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_2 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_2 emission factor to determine CO_2 emissions.

The carbonate fraction method calculates the amount of CO_2 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_2 emission factor to determine CO_2 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_2 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_2 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_2O 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_2, N_2O, and CH_4 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_2O 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_2O from the absorber tail gas vent and the production rate for that train.

When N_2O abatement devices (such as nonselective catalytic reduction) are used, adjust the N_2O process emissions for the amount of N_2O 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_2O 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_2O emissions factor is sufficient to accurately calculate N_2O 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_2O emissions from nitric acid production. Specifically the commenters asked that EPA allow the use of N_2O and flow CEMS to directly measure N_2O 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_2O analyzers to determine the amount of N_2O sent to control devices and conduct a performance test measuring control device destruction efficiency for each control device and then calculate N_2O emissions.

Commenters also asked that finalizing a methodology for N_2O 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_2O emissions, such as N_2O 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_2O CEMS. EPA understands the need to further evaluate and establish alternative comparable or potentially more accurate methods for sources to use in calculating N_2O 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_2O emissions (including N_2O CEMS).

The final rule allows the use of existing process flow meters and process knowledge in the determination of the destruction efficiency of N_2O 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_2O 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_2O emissions so we need production rate in order to verify the N_2O 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_2O 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_2, CH_4, and N_2O process emissions from each petrochemical production unit. Process emissions include CO_2 generated by reaction in the process. Process emissions also include CO_2, CH_4, and N_2O 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_2, N_2O, and CH_4 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_2 captured must also be reported by following the requirements of 40 CFR part 98, subpart PP.

GHG Emissions Calculation and Monitoring. CO_2 process emissions from petrochemical production must be determined by one of three methods. Process emissions include emissions from CO_2 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_2 emitted from each stack (except flare stacks). For each stack that includes emissions from combustion of process off-gas, reporters must calculate CH_4 and N_2O emissions by the procedures specified in 40 CFR part 98, subpart C. For each flare, the final rule requires CO_2, CH_4, and N_2O emissions to be calculated using the procedures in 40 CFR 98.253(b) (Petroleum Refineries). If CO_2 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_2, CH_4, and N_2O 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_2 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_2, 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_2 emissions (i.e., the Tier 4 methodology in 40 CFR part 98, subpart C) is also a good way to measure CO_2 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_2 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_2 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_2 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_2 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_2 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_2	CH_4	N_2O
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_2, CH_4 and N_2O emissions using the calculation methods described below for each refinery process.

For CO_2 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_2 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_2 emissions according to the requirements specified in 40 CFR part 98, subpart C or (2) calculate CO_2 emissions using the methods summarized below.

Flares. CO_2 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_2 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_4 and N_2O 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_2 emissions must be calculated using the volumetric flow rate of the exhaust gas (measured or calculated) and hourly measured carbon monoxide (CO) and CO_2 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_2 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_4 and N_2O emissions may be measured or may be calculated using the CO_2 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_2 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_2 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_4 and N_2O emissions from coke calcining units may be measured or calculated using the calculated CO_2 emissions and default emission factors.

Asphalt Blowing Operations. For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, CH_4 and CO_2 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_4 and CO_2 emissions must be calculated by assuming 98 percent of the CH_4 and other hydrocarbons generated by the asphalt blowing operation are converted to CO_2.

Delayed Coking Units. CH_4 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_4 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_2, CH_4, or N_2O 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_4 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_4 emissions from equipment leaks must be calculated using either default emission factors or process-specific CH_4 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_4 emissions depends on the material stored. For storage tanks used to store unstabilized crude oil, facilities must use either: (1) The CH_4 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_4 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_4 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_4 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_4 emissions only for loading materials that have an equilibrium vapor-phase CH_4 concentration equal to or greater than 0.5 percent by volume. Other facilities may assume zero CH_4 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_4 emissions to account for uncombusted methane.
- The final rule allows engineering calculations to determine CO_2 emissions for catalytic cracking units and fluid coking units below 10,000 bbl/stream day that do not have CO_2/CO/O_2 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_2, CH_4 and N_2O 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_4 and N_2O emissions within the Petroleum Refinery source category. Many commenters cited the TSD, which indicated that N_2O emissions account for 0.09 percent of the GHG emissions and CH_4 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_4 and N_2O 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_X emissions, but we have no data to determine the fraction of NO_X that is N_2O. With the increased use at refineries of NO_X control devices, such as low-NO_X burners, low excess air, selective catalytic reduction (SCR) systems, and selective non-catalytic reduction (SNCR) systems, it seems plausible that N_2O may be a more significant portion of a refinery's NO_X 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_2O (and CH_4) 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_4 and N_2O 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_2 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_2 and CH_4 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_2 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_2 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_4 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_2 emissions for catalytic cracking units below 10,000 bbl/stream day that do not have CO_2/CO/O_2 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_2 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_2, N_2O, and CH_4 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_2 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_2 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_2 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_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the CO_2 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_2O_5). 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_2 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

For pulp and paper mills ...	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated ...					
	CO_2	Biogenic CO_2	CH_4	N_2O	Biogenic CH_4	Biogenic N_2O
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_2	Biogenic CO_2	CH_4	N_2O	Biogenic CH_4	Biogenic N_2O
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_2 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_2 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_4 and N_2O 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_2, CH_4, and N_2O emissions from combustion [21] of fossil fuels in pulp mill lime kilns using direct measurement of fossil fuels consumed and default emission factors and HHV found in 40 CFR part 98, subparts AA and C, respectively.

• *Makeup chemicals:* Calculate CO_2 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_2 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.''

[21] Biogenic CO_2 from the conversion of $CaCO_3$ to CaO in kraft or soda pulp mill lime kilns is accounted for in the biogenic CO_2 emission factor for the recovery furnace.

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 ($CaCO_3$ and Na_2CO_3) 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 where 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_2 and CH_4 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_2, N_2O, and CH_4 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_2 emissions, reporters must use one of the following methods, as appropriate:

- Most reporters can elect to calculate and report process CO_2 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_2 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_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack. In such cases, the reporter cannot use the CO_2 calculation approach (2) outlined in the above bullet.

For CH_4 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_2. 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_2 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_2 process emissions from soda ash manufacturing, reported for each manufacturing line.
- CO_2 combustion emissions from each soda ash manufacturing line.
- N_2O and CH_4 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_2, N_2O, and CH_4 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_2 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_2 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_2 emissions or (2) calculate CO_2 process emissions using the procedures specified in 40 CFR part 98, subpart CC and summarized below.

• If using approach 2, calculate process CO_2 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_2 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_2 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_2 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_2 emissions from each soda ash manufacturing line under 40 CFR part 98, subpart CC (Soda Ash Manufacturing), and report combustion CO_2 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_2 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_2 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_2 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_2 emissions from this production method are likely to be significant and exceed 25,000 metric tons CO_2e. 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_2 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_2 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_2 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_6) 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_2 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_2, N_2O, and CH_4 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_2 process emissions using one of two methods, as appropriate:

- Most reporters can elect to calculate and report process CO_2 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_2 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_2 emissions, then the reporter must use the CEMS to measure and report combined CO_2 emissions from that stack instead of using the calculation procedures described below.
- If using approach #2, calculate the process CO_2 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_2. 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_2 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_2 emissions. Production capacity and annual production of titanium dioxide are required for EPA to verify annual CO_2 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_2 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_2 process emissions from each Waelz kiln and electrothermic furnace used for zinc production.
- CO_2, N_2O, and CH_4 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_2 process emissions using one of two methods, as appropriate:

• Most reporters can elect to calculate and report process CO_2 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_2 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_2 emissions, then the CEMS must be used to measure and report combined CO_2 emissions from that stack, instead of the calculation procedure described below.

• If using approach #2, calculate process CO_2 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_4 generation and CH_4 emissions from the landfill.

• Annual CH_4 destruction (for landfills with gas collection and control systems).

• Annual CO_2, CH_4, and N_2O 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_4 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_4 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_4 generation to account for soil oxidation (CH_4 that is converted to CO_2 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_4 generation and CH_4 emissions.

Facilities that collect and control landfill gas must calculate the annual quantity of CH_4 recovered and destroyed based on either continuous or weekly monitoring of landfill gas flow rate, CH_4 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_4 emissions in two ways and report both results. Emissions must be calculated by:

1. Subtracting the measured amount of CH_4 recovered from the modeled annual CH_4 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_4 recovered to calculate CH_4 generation, then subtracting the measured amount of CH_4 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 founds 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_4 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 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_4, 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_2e 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_4 and N_2O emissions from the system components listed above. For those manure management systems that include digesters, CH_4 generated and destroyed, as well as any CH_4 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_4-producing potential of the managed manure and CH_4 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_2O 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_4 emissions and the annual mass of CH_4 generated and destroyed based on the following inputs and data:

- Continuous monitoring of CH_4 concentration, flow rate, temperature, and pressure of the digester gas.
- CH_4 destruction efficiency of the destruction device and fugitive (leakage) emissions.
- The CH_4 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_4 and N_2O 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_4 emissions from manure management systems totaled 44 million metric tons CO_2e, and N_2O emissions were 14.7 million metric tons CO_2e in 2007; manure management systems account for 7.5 percent of total anthropogenic CH_4 emissions and 4.7 percent of N_2O 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_2 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_2 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_4 or N_2O.

GHG Emissions Calculation and Monitoring. For each type of coal-to-liquid product, suppliers must calculate CO_2 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_2 emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year.

• CO_2 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_4 or N_20.

GHG Emissions Calculation and Monitoring. Suppliers of petroleum products must choose one of two methods to calculate CO_2 emissions that would result from the combustion or oxidation of each petroleum product and natural gas liquid:

• Method 1: Use the default CO_2 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_2 emissions that would result from the combustion or oxidation of biomass co-processed with petroleum feedstock, reporters must use a CO_2 emission factor that is provided in the regulations for each type of biomass.

In calculating total CO_2 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_2 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_2 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_2 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_2 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_2 per year for importers and exporters of petroleum products and natural gas liquids; the threshold is based on a calculation of CO_2 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_2 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_2 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_2 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_2 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_2 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_2 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_2 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 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_2 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_2 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_2 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_2 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 addition 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_2 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_2 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_2 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_4 or N_20.

GHG Emissions Calculation and Monitoring. Reporters must use one of two methods to calculate the CO_2 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_2 emissions factor. This method is most appropriate for liquid fuels.
- The second method uses either a measured or default CO_2 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_2 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_2 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_2 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 long 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_2O, except those that produce only HFC–23 generated as a byproduct during HCFC–22 production.

• Bulk importers of fluorinated GHGs or N_2O, if the total combined imports of industrial GHGs and CO_2 exceed 25,000 metric tons of CO_2e per year.

• Bulk exporters of fluorinated GHGs or N_2O, if the total combined exports of industrial GHGs and CO_2 exceed 25,000 metric tons CO_2e 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_2O and each fluorinated GHG produced, imported, exported, transformed, or destroyed during the calendar year. Importers and exporters of CO_2 must calculate and report annual amounts of CO_2 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_2O 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_2e.

• 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_6 and NF_3) 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_2e. For purposes of determining whether or not the 25,000 metric ton CO_2e 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_2e. 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_2)

1. Summary of the Final Rule

Source Category Definition. Under the rule, suppliers of CO_2 consist of the following:

- Facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground.
- Facilities with CO_2 production wells that extract a CO_2 stream for the purpose of supplying CO_2 for commercial applications.
- Importers of bulk CO_2, if total combined imports of CO_2 and other GHGs exceed 25,000 metric tons of CO_2 equivalent (CO_2e) per year.
- Exporters of bulk CO_2, if total combined exports of CO_2 and other GHGs exceed 25,000 metric tons CO_2e per year.

This source category is focused on upstream supply. It does not cover: Storage of CO_2 above ground or in geologic formations; use of CO_2 in enhanced oil and gas recovery; transportation or distribution of CO_2; or purification, compression, on-site use of CO_2 captured on site, or processing of CO_2. This source category does not include CO_2 imported or exported in equipment, such as fire extinguishers.

Suppliers of CO_2 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_2 must report the mass of CO_2 in a stream captured from production process units and extracted from production wells, and the mass of CO_2 in containers that is imported and exported.

GHG Emissions Calculation and Monitoring. While this source category is focused on upstream supply of CO_2, EPA recognizes that all CO_2 supplied to the economy does not necessarily result in an emission. There are a variety of downstream applications for CO_2—some applications are emissive and some are non-emissive. Under this rulemaking, a CO_2 supplier facility must calculate the mass of CO_2 supplied quarterly by measuring the mass or volumetric flow of gas and multiplying by the CO_2 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_2 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_2 supply than annual measurements. EPA requires these quarterly numbers to be reported so that EPA can electronically verify the calculations. The CO_2 supplier must also provide information on the downstream CO_2 application, if known. Reporters must use the following methodologies, as applicable, for calculating CO_2 supplied:

- For suppliers that make measurements with mass flow meters, calculate quarterly for each meter the total mass of CO_2 in a CO_2 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_2 in a CO_2 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_2 in containers must calculate the total mass of CO_2 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_2 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_2 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_2 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_2 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_2 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_2 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_2.

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_2 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_2 supplied to the economy should not be characterized as an emission. Some in this group of comments specified that much of the supplied CO_2 is stored at enhanced oil recovery (EOR) sites, which are ''closed systems'', rather than emitted. In general, these same commenters stated that any CO_2 reporting requirements placed by EPA on industry should be placed on downstream CO_2 users, such as EOR facilities, rather than CO_2 suppliers and should be for actual emissions only. Other comments echoed that EPA needs to collect data from recipients of supplied CO_2 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_2. 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_2 geologic sequestration effectiveness; and tracking the CO_2 throughout the entire carbon dioxide capture and sequestration (CCS) chain for the purposes of adjusting CO_2 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_2 supplied to the economy as emissions and recognizes that there are a variety of applications for CO_2, both emissive and non-emissive. CO_2 supplied to the economy would result in an emission if the CO_2 were used in an application which would ultimately result in release of the CO_2 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_2 has been or will be released to the atmosphere (e.g., emitted), the Agency needs information on the downstream CO_2 end-use. In today's final rulemaking, CO_2 suppliers must provide information on the downstream CO_2 application, if known. EPA believes information on the end-use will provide some idea of the amounts of CO_2 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_2 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_2 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_2 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_2 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_2 securely sequestered and the potential for release of CO_2 during EOR operations.

Given the comments in support of downstream data collection, particularly with respect to EOR systems and CO_2 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_2 emitted and geologically sequestered at active EOR facilities and geologic sequestration sites where CO_2 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_2 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_2 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_2, 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_2. 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_2 suppliers and the reporting requirements in new rulemaking for CO_2 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_2 supply will assist EPA in developing future climate policy. Commenters stated that they do not believe CO_2 supply data will provide EPA with useful information. Commenters stated that data collection from CO_2 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_2 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_2 Data on CO_2 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_2 as an end-user.

Though CO_2 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_2 emissions from fossil fuel combustion in 2007. The stationary sources represent a wide variety of sectors amenable to CO_2 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_2 reservoir.[22]

With this rule, EPA will begin building capacity to track the growth in CO_2 supply and learn about its disposition throughout the economy. EPA has concluded that we need data now from CO_2 suppliers—both industrial facilities and CO_2 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_2 captured from industrial facilities will offset or displace CO_2 produced from natural formations. Even after EPA begins collecting data on CO_2 geologic sequestration under the proposed new rulemaking (discussed above), EPA will continue to need data from CO_2 suppliers in order to track any CO_2 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_2 that is not supplied to downstream customers is a covered facility. Another asked that a pulp and paper mill that transfers a CO_2 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_2 stream for further processing, separating CO_2 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_2 stream that has already been separated and removed from a manufacturing process or that has already been extracted from CO_2 production wells in order to do any of the following: Store it in above ground storage of CO_2; 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_2 from an industrial or manufacturing process or physically extracts CO_2 from production wells because we concluded that the entity with first touch of the CO_2 supply was the most logical point of coverage. We wanted to minimize any unnecessary duplicative reporting of the same CO_2 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_2 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_2 that is captured or extracted for purposes of sequestration or supply to other facilities for commercial applications because we concluded that CO_2 captured and used on-site is equivalent to an intermediary step in production rather than an actual supply of CO_2.

Comment: EPA received a comment requesting that ethanol plants and other facilities capturing CO_2 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_2 from the combustion of biomass and biomass-based fuels from emissions of CO_2 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

[22] 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_2. We have concluded that data on capture of biogenic CO_2 would be useful and informative because biogenic CO_2 can potentially be stored in GS sites, or displace fossil CO_2 applications. We need a full picture of the CO_2 being supplied into the economy. Though CO_2 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_2 for sequestration is necessary for a complete picture. Thus, a facility that captures CO_2 from biomass and otherwise meets the applicability test is covered under 40 CFR part 98, subpart PP and is required to report all CO_2 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_2 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_2 as long as the CBI is protected. Some commenters indicated that CO_2 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_2 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_2 can be reported, irrespective of technical or physical conditions. Therefore, a reporter that measures CO_2 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_2 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_2 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_2 already operate mass or volumetric flow meters, or already determine quantities of CO_2 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,[23] this rule includes new requirements for reporting emission rates of GHGs.[24] Mobile source engine manufacturers have been measuring CO_2 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_2 for all engines beginning with model year 2011 and other GHGs in subsequent model years.[25] 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.[26]

In addition to CO_2, most manufacturers will now be required to report on two other major GHGs emitted by mobile sources, nitrous oxide (N_2O) and methane (CH_4). Although most current engines have relatively low emission rates of these GHGs compared to CO_2, these compounds have global warming potentials significantly higher than CO_2. 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_2O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO_X emissions. Therefore, we will require that manufacturers begin to measure and report N_2O emissions, but only for engine models that incorporate NO_X aftertreatment technology (as shown in Table IV–1 of this preamble). The program will not require N_2O reporting before model year 2013, and the requirements will only apply to new engines equipped with NO_X aftertreatment technology. (Manufacturers of some engine categories have employed aftertreatment for many years to meet NO_X standards; for other engine categories, manufacturers are unlikely to introduce NO_X aftertreatment technologies for some years to come.)

Emissions of CH_4 are a part of overall hydrocarbon emissions from mobile sources. Because CH_4 is not very reactive in the atmosphere, EPA has often excluded CH_4 from mobile source hydrocarbon regulations since it has not traditionally been a major determinant of ozone formation.[27] The new reporting requirements are necessary to evaluate the magnitude of mobile source CH_4 emissions from a GHG (rather than ozone precursor) perspective.

As described above, we are finalizing manufacturer reporting requirements for N_2O and CH_4 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

[23] Manufacturers of light-duty vehicles, light-duty trucks, and medium-duty passenger vehicles are not covered in this final rule.

[24] 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.

[25] For aircraft engine manufacturers, reporting requirements will apply for the engine models in production in 2011.

[26] Small business manufacturers will continue to be subject to measurement and/or reporting requirements for compliance with existing regulations.

[27] But *see Ford Motor Co.* v. *EPA,* 604 F. 2d 685 (D.C. Cir. 1979) (permissible for EPA to regulate CH_4 under CAA section 202 (b)). In addition, although CH_4 is not itself regulated, manufacturers subject to ''non-methane hydrocarbon'' standards have needed to determine CH_4 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_2O and CH_4 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_2O and/or CH_4 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_2O test data from relevant testing programs (by such sources as industry collaboratives and/or from the suppliers of the catalytic NO_X 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_4 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_2 emission rates beginning in 2011 (for aircraft engines, they will report CO_2 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_2O or CH_4 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_2O and CH_4 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_X after treatment devices in the foreseeable future, we did not propose requiring N_2O 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_4, as we learned that aircraft jet turbine engines have been shown to consume CH_4 from the ambient air during the dominant operating modes.[28] However, unlike NO_X emissions from most mobile sources, NO_X emissions from aircraft have been shown to make a potential contribution to climate change.[29] For this reason, we are requiring that aircraft engine manufacturers report the NO_X 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_X as part of current criteria pollutant certification requirements. NO_X emissions rate data from LTO modes will support modeling of overall NO_X 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_2	N_2O[a]	CH_4
Highway Heavy-Duty (engine and vehicle)	2011	2013 or NO_X AT	2012
Nonroad Diesel	2011	2013 or NO_X AT	2012
Marine Diesel (other than C3)	2011	2013 or NO_X AT	2012
C3 Marine	2011	None	None
Locomotives	2011	2013 or NO_X AT	2012
Small Spark-Ignition	2011	2013 or NO_X AT	2012
Large Spark-Ignition	2011	2013 or NO_X AT	2012
Marine Spark-Ignition	2011	2013 or NO_X AT	2012
Snowmobiles	2011	2013 or NO_X AT	2012
Highway Motorcycles	2011	2013 or NO_X AT	2012
Off Highway Motorcycles/ATVs	2011	2013 or NO_X AT	2012
Aircraft[b]	2011	None	None

[a] N_2O reporting for new engines begins in 2013 or when the manufacturer introduces NO_X aftertreatment technology, whichever is later.
[b] Applies to all turbofan and turbojet engines in production in 2011 with a rated output greater than 26.7 kilonewtons. Reporting of NO_X also required.

[28] Aerodyne, Rich Miake-Lye, AAFEX Methane presentation at the Seventh Meeting of Primary Contributors for the Aviation Emissions Characterization Roadmap, June 9–10, 2009.

[29] 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_2O for all of their engines, and instead will require N_2O reporting only for engines that use NO_X exhaust aftertreatment technology.
- We have delayed the proposed MY 2011 start year for N_2O reporting until MY 2013, and later for categories where the manufacturer has not applied NO_X aftertreatment technology.
- We have added additional emission test methods that manufacturers can choose for measuring N_2O, to assure that an appropriate method is available for any foreseeable circumstance (including the need to measure very low N_2O emission rates).
- The final rule incorporates an opportunity for a manufacturer to provide EPA with appropriate alternative information in lieu of N_2O and/or CH_4 testing, as described above.
- We have added one year of lead time to the proposed start year for reporting of CH_4 emissions, until 2012.
- We are not finalizing our proposal to require reporting of CH_4 for aircraft engines because, for the dominant operating modes, jet engines may consume CH_4 in the air.
- We are finalizing a requirement that we took comment on in the proposal to have aircraft engine manufacturers report NO_X emissions data they already collect, since, at altitude, NO_X 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_2 and NO_X 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_2O and CH_4, was too aggressive; and commented that the proposed test procedure for N_2O was not adequate.

Response: We still conclude that there is significant value to collecting CO_2, N_2O, and CH_4 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_2O and CH_4 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_2O and CH_4, we agree that revisions in the proposed provisions are warranted. We have limited the reporting requirements for N_2O to engines equipped with NO_X 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_2O are related to catalytic treatment of engine exhaust, specifically aftertreatment of NO_X emissions, and we have concluded that collecting N_2O emissions data from engines without NO_X aftertreatment technology would provide marginal value to the agency. We expanded the number of approved test methods for N_2O measurement since we learned from comments and our own technical research that our proposed test methods for N_2O were not appropriate for every foreseeable circumstance, including measurement of very low levels of N_2O. We also extended the lead time available to manufacturers before N_2O and CH_4 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_4 and N_2O 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_2O and/or CH_4 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_2 emissions from each mode of the LTO [30] cycle used in the emission certification test, as proposed, is acceptable as long as existing methods for CO_2 are retained. In particular, commenters noted that reporting would result in minimal

[30] Modes of the landing and takeoff cycle are taxi/idle, takeoff, climb out, and approach.

burden as long as CO_2 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_2 from the LTO cycle is unjustified because LTO measurements do not include CO_2 emissions from an entire aircraft flight, which is affected by the propulsion system, drag, etc.

Response: We determined that calculating aircraft engine CO_2 emissions from fuel mass flow rate measurements is an appropriate method for reporting CO_2 emissions. Therefore, for turbofan and turbojet engines of rated output greater than 26.7 kilonewtons, we are finalizing that manufacturers report CO_2 separately for each mode of the LTO cycle by calculation of CO_2 from fuel mass flow rate measurements or, alternatively, according to the measurement criteria for CO_2 in Appendices 3 and 5 to ICAO Annex 16, volume II. Comprehensive and consistent reporting of LTO CO_2 emissions, along with knowledge of aircraft aerodynamic performance, will support modeling of full-flight CO_2 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_4 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_4, manufacturers replied that test stands are not currently equipped to measure CH_4, and thus, they would incur additional costs to measure CH_4. Second, manufacturers noted that aircraft jet turbine engines have been shown to be consumers of CH_4 from the ambient air during the dominant operating modes (CH_4 is emitted at aircraft engine idle operation, but at higher power modes aircraft engines usually consume CH_4. Over the range of engine operating modes—including cruise—aircraft engines are typically net consumers of CH_4).

Response: Given that aircraft engines are likely net consumers of CH_4 and that manufacturers do not currently collect CH_4 data as part of existing test procedures, we are not requiring CH_4 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_X emissions in the four LTO test modes and for the overall LTO cycle. Manufacturers commented that NO_X 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_X since they currently do not report the data to EPA. In addition, environmental organizations commented that NO_X 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_X 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_X 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_X emissions in each of the four LTO test modes in order to comply with the LTO NO_X 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_X emissions rate data will support modeling of overall NO_X 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_2e. 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_2O) per unit of time and CO_2e 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 is it 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*. 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.[31]

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

[31] 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_2e 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_2e). 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 [2]	
		(Million of $MtCO_2e$)	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_2)	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
Total	10,152	3,827	100	39.6	100	132.0	100

[1] Emissions from upstream facilities are excluded from these estimates to avoid double counting.

[2] 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_2e)	Facilities required to report	Total costs (million $2006)	Downstream emissions reported ($MtCO_2e$/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_2e 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 [1]				Downstream [2 3 4]			
Source category	No. of reporters	Emissions coverage (%) [10]	First year cost (millions)	Source category	No. of reporters [2]	Emissions coverage [3 7 10] (%)	First year cost [3] (millions)
Coal Supply	0	0	$0.00	Coal [5 6] Combustion	N/A	99.0	N/A
Petroleum Supply	315	100	3.66	Petroleum [5] Combustion [9]	N/A	20.0	N/A
Natural Gas Supply	1,502	68	6.76	Natural Gas [5] 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 [8] and Engine Manufacturers.	317	80	8.61

Notes

1 Most upstream facilities (e.g., refineries) are also direct emitters of greenhouse gases, and are included in the downstream side of the table.

2 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).

3 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.

4 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_2e/yr).

5 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.

6 Approximately 90 percent of downstream coal combustion emissions are already reported to EPA through requirements for electricity generating units under the ARP.

7 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.

8 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_2, CH_4, and N_2O from the products they supply. This source category is neither upstream nor downstream, but is included in the downstream column for illustrative purposes.

9 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.

10 Emissions coverage from the combustion of fossil fuels upstream represents CO_2 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 [1] (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

[1] 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_2e 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).[32] 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 [a]

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 [f] (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

[32] 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 [a]—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 [f] (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.	([c])	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.	([c])	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

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

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

[b] 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.

[c] 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.

[d] 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.

[e] 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.

[f] 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_2e 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 [33]. This study provides industry-average CO_2 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.

[33] 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_2 Emissions Rule? Available at: *http://www.nicholas.duke.edu/institute/10Kton.pdf.*

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_2e 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_2e 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_2 allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

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

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

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.[34]

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 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[35]. 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

[34] 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.

[35] 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.[36] 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.

[36] 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.*

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 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_2, N_2O, and CH_4 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_2 and 2012 for CH_4. The requirements of this paragraph (n) related to N_2O emissions apply for engine families that depend on NO_x 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_2, N_2O, and CH_4 for each test. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/bhp-hr.

(2) Round N_2O to the nearest 0.001 g/bhp-hr.

(3) Round CH_4 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_4 and N_2O in alphanumeric order to read as follows:

§ 86.078–3 Abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

Subpart E—[Amended]

■ 4. Section 86.403–78 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 86.403–78 Abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O 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_2, N_2O, and CH_4 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_2O and CH_4. Report these values in your application for certification. The requirements of this paragraph (e) apply starting with model year 2011 for CO_2 and 2012 for CH_4. The requirements of this paragraph (e) related to N_2O emissions apply for engine families that depend on NO_X 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_2O and CH_4; other manufacturers may provide appropriate data and/or information and omit measurement of N_2O and CH_4 as described in 40 CFR 1065.5. Use the same measurement methods as for your other results to report a single value for CO_2, N_2O, and CH_4. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/km.

(2) Round N_2O to the nearest 0.001 g/km.

(3) Round CH_4 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.