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40 CFR Parts 86, 87, 89, et al.
Mandatory Reporting of Greenhouse Gases; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 86, 87, 89, 90, 94, 98, 600, 1033, 1039, 1042, 1045, 1048, 1051, 1054, and 1065

[EPA–HQ–OAR–2008–0508; FRL–8782–1]

RIN 2060–A079

Mandatory Reporting of Greenhouse Gases

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing a regulation to require reporting of greenhouse gas emissions from all sectors of the economy. The rule would apply to fossil fuel suppliers and industrial gas suppliers, as well as to direct greenhouse gas emitters. The proposed rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions.

DATES: Comments must be received on or before June 9, 2009. There will be two public hearings. One hearing was held on April 6 and 7, 2009, in the Washington, DC, area (One Potomac Yard, 2777 S. Crystal Drive, Arlington, VA 22202). One hearing will be on April 16, 2009 in Sacramento, CA (Sacramento Convention Center, 1400 J Street, Sacramento, CA 95814). The April 16, 2009 hearing will begin at 9 a.m. local time.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2008–0508, by one of the following methods:

- Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments.
- E-mail: *a-and-r-Docket@epa.gov.*
- Fax: (202) 566–1741.
- Mail: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mailcode 6102T, Attention Docket ID No. EPA–HQ–OAR–2008–0508, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.
- Hand Delivery: EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

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

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

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

SUPPLEMENTARY INFORMATION:

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

Regulated Entities. The Administrator determines that this action is subject to the provisions of 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.''). This is a proposed regulation. If finalized, these regulations would affect owners and operators of fuel and chemicals suppliers, direct emitters of GHGs and manufacturers of mobile sources and engines. Regulated categories and entities would 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.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
	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	Owners and operators of Portland Cement manufacturing plants.
Electronics Manufacturing	334111	Microcomputers manufacturing facilities.
	334413	Semiconductor, photovoltaic (solid-state) device manufacturing facilities.
	334419	LCD unit screens manufacturing facilities.
		MEMS manufacturing facilities.
Ethanol Production	325193	Ethyl alcohol manufacturing facilities.
Ferroalloy Production	331112	Ferroalloys manufacturing facilities.
Fluorinated GHG Production	325120	Industrial gases manufacturing facilities.
Food Processing	311611	Meat processing facilities.
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.
	311421	Fruit and vegetable canning 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.
Magnesium Production	331419	Primary refiners of nonferrous metals by electrolytic methods.
	331492	Secondary magnesium processing plants.
Nitric Acid Production	325311	Nitric acid manufacturing facilities.
Oil and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	325212	Synthetic rubber manufacturing facilities.
Petrochemical Production	32511	Ethylene dichloride manufacturing facilities.
	325199	Acrylonitrile, ethylene oxide, methanol manufacturing facilities.
	325110	Ethylene manufacturing 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.
Sulfur Hexafluoride (SF_6) from Electrical Equipment.	221121	Electric bulk power transmission and control facilities.
Titanium Dioxide Production	325188	Titanium dioxide manufacturing facilities.
Underground Coal Mines	212113	Underground anthracite coal mining operations.
	212112	Underground bituminous coal mining operations.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust reclaiming facilities, recovering from scrap and/or alloying purchased metals.
Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
	322110	Pulp mills.
	322121	Paper mills.
	322122	Newsprint mills.
	322130	Paperboard mills.
	311611	Meat processing facilities.
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.
	311421	Fruit and vegetable canning facilities.
Wastewater Treatment	322110	Pulp mills.
	322121	Paper mills.
	322122	Newsprint mills.
	322130	Paperboard mills.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
	311611	Meat processing facilities.
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.
	311421	Fruit and vegetable canning facilities.
	325193	Ethanol manufacturing facilities.
	324110	Petroleum refineries.
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 and Coal-based Products.	212111	Bituminous, and lignite coal surface mining facilities.
	212113	Anthracite coal mining facilities.
	212112	Underground bituminous coal mining facilities.
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	336112	Light-duty vehicles and trucks manufacturing facilities.
	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 regulated by this action. Table 1 of this preamble lists the types of facilities that EPA is now aware could be potentially affected by this action. Other types of facilities not listed in the table could also be subject to reporting requirements. To determine whether your facility is affected by this action, you should carefully examine the applicability criteria found in proposed 40 CFR part 98, subpart A. 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 would be affected by the proposed 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 would be relevant for all reporters.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS

Source category (and main applicable subpart)	Subparts recommended for review to determine applicability
General Stationary Fuel Combustion Sources	General Stationary Fuel Combustion.
Electricity Generation	General Stationary Fuel Combustion, Electricity Generation, Suppliers of CO_2, Electric Power Systems.
Adipic Acid Production	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.
Electronics Manufacturing	General Stationary Fuel Combustion.
Ethanol Production	General Stationary Fuel Combustion, Landfills, Wastewater Treatment.
Ferroalloy Production	General Stationary Fuel Combustion.
Fluorinated GHG Production	General Stationary Fuel Combustion.
Food Processing	General Stationary Fuel Combustion, Landfills, Wastewater Treatment.
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.
Lead Production	General Stationary Fuel Combustion.
Lime Manufacturing	General Stationary Fuel Combustion.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS—Continued

Source category (and main applicable subpart)	Subparts recommended for review to determine applicability
Magnesium Production	General Stationary Fuel Combustion.
Nitric Acid Production	General Stationary Fuel Combustion, Adipic Acid.
Oil and Natural Gas Systems	General Stationary Fuel Combustion, Petroleum Refineries, Suppliers of Petroleum Products, Suppliers of Natural Gas and NGL, Suppliers of CO$_2$.
Petrochemical Production	General Stationary Fuel Combustion, Ammonia, Petroleum Refineries.
Petroleum Refineries	General Stationary Fuel Combustion, Hydrogen, Landfills, Wastewater Treatment, Suppliers of Petroleum Products.
Phosphoric Acid Production	General Stationary Fuel Combustion.
Pulp and Paper Manufacturing	General Stationary Fuel Combustion, Landfills, Wastewater Treatment.
Silicon Carbide Production	General Stationary Fuel Combustion.
Soda Ash Manufacturing	General Stationary Fuel Combustion.
Sulfur Hexafluoride (SF$_6$) from Electrical Equipment	General Stationary Fuel Combustion.
Titanium Dioxide Production	General Stationary Fuel Combustion.
Underground Coal Mines	General Stationary Fuel Combustion, Suppliers of Coal.
Zinc Production	General Stationary Fuel Combustion.
Landfills	General Stationary Fuel Combustion, Ethanol, Food Processing, Petroleum Refineries, Pulp and Paper.
Wastewater Treatment	General Stationary Fuel Combustion, Ethanol, Food Processing, Petroleum Refineries, Pulp and Paper.
Manure Management	General Stationary Fuel Combustion.
Suppliers of Coal	General Stationary Fuel Combustion, Underground Coal Mines.
Suppliers of Coal-based Liquid Fuels	Suppliers of Coal, Suppliers of Petroleum Products.
Suppliers of Petroleum Products	General Stationary Fuel Combustion, Oil and Natural Gas Systems.
Suppliers of Natural Gas and NGLs	General Stationary Fuel Combustion, Oil and Natural Gas Systems, 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.

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

A/C air conditioning
AERR Air Emissions Reporting Rule
ANPR advance notice of proposed rulemaking
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
CARB California Air Resources Board
CBI confidential business information
CCAR California Climate Action Registry
CDX central data exchange
CEMS continuous emission monitoring system(s)
CERR Consolidated Emissions Reporting Rule
cf cubic feet
CFCs chlorofluorocarbons
CFR Code of Federal Regulations
CH$_4$ methane
CHP combined heat and power
CO$_2$ carbon dioxide
CO$_2$e CO$_2$-equivalent
COD chemical oxygen demand
DE destruction efficiency
DOD U.S. Department of Defense
DOE U.S. Department of Energy
DOT U.S. Department of Transportation
DE destruction efficiency
DRE destruction or removal efficiency
ECOS Environmental Council of the States
EGUs electrical generating units
EIA Energy Information Administration
EISA Energy Independence and Security Act of 2007
EO Executive Order
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
EU European Union
FTP Federal Test Procedure
FY2008 fiscal year 2008
GHG greenhouse gas
GWP global warming potential
HCFC–22 chlorodifluoromethane (or CHClF$_2$)
HCFCs hydrochlorofluorocarbons
HCl hydrogen chloride
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
ISO International Organization for Standardization
kg kilograms
LandGEM Landfill Gas Emissions Model
LCD liquid crystal display
LDCs local natural gas distribution companies
LEDs light emitting diodes
LNG liquified natural gas
LPG liquified petroleum gas
MEMS microelectricomechanical system
mmBtu/hr millions British thermal units per hour
MMTCO$_2$e million metric tons carbon dioxide equivalent
MSHA Mine Safety and Health Administration
MSW municipal solid waste
MW megawatts
N$_2$O nitrous oxide
NAAQS national ambient air quality standard
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
NIOSH National Institute for Occupational Safety and Health
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
POTWs publicly owned treatment works
PSD Prevention of Significant Deterioration
PV photovoltaic
QA quality assurance
QA/QC quality assurance/quality control
QAPP quality assurance performance plan
RFA Regulatory Flexibility Act
RFS Renewable Fuel Standard
RGGI Regional Greenhouse Gas Initiative

RIA	regulatory impact analysis
SAE	Society of Automotive Engineers
SAR	IPCC Second Assessment Report
SBREFA	Small Business Regulatory Enforcement Fairness Act
SF_6	sulfur hexafluoride
SFTP	Supplemental Federal Test Procedure
SI	international system of units
SIP	State Implementation Plan
SSM	startup, shutdown, and malfunction
TCR	The Climate Registry
TOC	total organic carbon
TRI	Toxic Release Inventory
TSCA	Toxics Substances Control Act
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
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
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

The proposed rule would require reporting of annual emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorochemicals (PFCs), and other fluorinated gases (e.g., nitrogen trifluoride and hydrofluorinated ethers (HFEs)). The proposed rule would apply to certain downstream facilities that emit GHGs (primarily large facilities emitting 25,000 tpy of CO_2 equivalent GHG emissions or more) and to upstream suppliers of fossil fuels and industrial GHGs, as well as to manufacturers of vehicles and engines. Reporting would be at the facility level, except certain suppliers and vehicle and engine manufacturers would report at the corporate level.

This preamble is broken into several large sections, as detailed above in the Table of Contents. Throughout the preamble we explicitly request comment on a variety of issues. The paragraph below describes the layout of the preamble and provides a brief summary of each section. We also highlight particular issues on which, as indicated later in the preamble, we would specifically be interested in receiving comments.

The first section of this preamble contains the basic background information about greenhouse gases and climate change. It also describes the origin of this proposal, our legal authority and how this proposal relates to other efforts to address emissions of greenhouse gases. In this section we would be particularly interested in receiving comment on the relationship between this proposal and other government efforts.

The second section of this preamble describes existing Federal, State, Regional mandatory and voluntary GHG reporting programs and how they are similar and different to this proposal. Again, similar to the previous section, we would like comments on the interrelationship of this proposal and existing GHG reporting programs.

The third section of this preamble provides an overview of the proposal itself, while the fourth section provides the rationale for each decision the Agency made in developing the proposal, including key design elements such as: (i) Source categories included, (ii) the level of reporting, (iii) applicability thresholds, (iv) reporting and monitoring methods, (v) verification, (vi) frequency and (vii) duration of reporting. Furthermore, in this section, EPA explains the distinction between upstream and downstream reporters, describes why it is necessary to collect data at multiple points, and provides information on how different data would be useful to inform different policies. As stated in the fourth section, we solicit comment on each design element of the proposal generally.

The fifth section of this preamble looks at the same key design elements for each of the source categories covered by the proposal. Thus, for example, there is a specific discussion regarding appropriate applicability thresholds, reporting and monitoring methodologies and reporting and recordkeeping requirements for each source category. Each source category describes the proposed options for each design element, as well as the other options considered. In addition to the general solicitation for comment on each design element generally and for each source category, throughout the fifth section there are specific issues highlighted on which we solicit comment. Please refer to the specific source category of interest for more details.

The sixth section of this preamble explains how EPA would collect, manage and disseminate the data, while the seventh section describes the approach to compliance and enforcement. In both sections the role of the States is discussed, as are requests for comment on that role.

Finally, the eighth section provides the summary of the impacts and costs from the Regulatory Impact Analysis and the last section walks through the various statutory and executive order requirements applicable to rulemakings.

A. What Are GHGs?

The proposed rule would cover the major GHGs that are directly emitted by human activities. These include CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and other specified fluorinated compounds (e.g., HFEs) used in boutique applications such as electronics and anesthetics. These gases influence the climate system by trapping in the atmosphere heat that would otherwise escape to space. The GHGs vary in their capacity to trap heat. The GHGs also vary in terms of how long they remain in the atmosphere after being emitted, with the shortest-lived GHG remaining in the atmosphere for roughly a decade and the longest-lived GHG remaining for up to 50,000 years. Because of these long atmospheric lifetimes, all of the major GHGs become well mixed throughout the global atmosphere regardless of emission origin.

Global atmospheric CO_2 concentration increased about 35 percent from the pre-industrial era to 2005. The global atmospheric concentration of CH_4 has increased by 148 percent from pre-industrial levels, and the N_2O concentration has increased 18 percent. The observed increase in concentration of these gases can be attributed primarily to human activities. The atmospheric concentration of industrial fluorinated gases—HFCs, PFCs, SF_6—and other fluorinated compounds are relatively low but are increasing rapidly; these gases are entirely anthropogenic in origin.

Due to sheer quantity of emissions, CO_2 is the largest contributor to GHG concentrations followed by CH_4. Combustion of fossil fuels (e.g., coal, oil, gas) is the largest source of CO_2 emissions in the U.S. The other GHGs are emitted from a variety of activities. These emissions are compiled by EPA in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and reported to the UNFCCC [1] on an annual basis.[2] A more detailed discussion of the Inventory is provided in Section I.D below.

Because GHGs have different heat trapping capacities, they are not directly comparable without translating them into common units. The GWP, a metric that incorporates both the heat-trapping ability and atmospheric lifetime of each GHG, can be used to develop comparable numbers by adjusting all GHGs relative to the GWP of CO_2. When quantities of the different GHGs are multiplied by their GWPs, the different GHGs can be compared on a CO_2e basis. The GWP of CO_2 is 1.0, and the GWP of other GHGs are expressed relative to CO_2. For example, CH_4 has a GWP of 21, meaning each metric ton of CH_4 emissions would have 21 times as much impact on global warming (over a 100-year time horizon) as a metric ton of CO_2 emissions. The GWPs of the other gases are listed in the proposed rule, and range from the hundreds up to 23,900 for SF_6.[3] Aggregating all GHGs on a CO_2e basis at the source level allows a comparison of the total emissions of all the gases from one source with emissions from other sources.

For additional information about GHGs, climate change, climate science, etc. please see EPA's climate change Web site found at *http://www.epa.gov/climatechange/*.

B. What Is Climate Change?

Climate change refers to any significant changes in measures of climate (such as temperature, precipitation, or wind) lasting for an extended period. Historically, natural factors such as volcanic eruptions and changes in the amount of energy released from the sun have affected the earth's climate. Beginning in the late 18th century, human activities associated with the industrial revolution

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[1] For more information about the UNFCCC, please refer to: *http://www.unfccc.int*. See Articles 4 and 12 of the UNFCCC treaty. Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available * * * national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies * * *".

[2] The U.S. submits the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* to the Secretariat of the UNFCCC as an annual reporting requirement. The UNFCCC treaty, ratified by the U.S. in 1992, sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The U.S. has submitted the GHG inventory to the United Nations every year since 1993. The annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* is consistent with national inventory data submitted by other UNFCCC Parties, and uses internationally accepted methods for its emission estimates.

[3] EPA has chosen to use GWPs published in the IPCC SAR (furthermore referenced as "SAR GWP values"). The use of the SAR GWP values allows comparability of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the UNFCCC. To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. For those fluorinated compounds included in this proposal that not listed in the SAR, EPA is using the most recent available GWPs, either the IPCC Third Assessment Report or Fourth Assessment Report. For more specific information about the GWP of specific GHGs, please see Table A–1 in the proposed 40 CFR part 98, subpart A.

have also changed the composition of the earth's atmosphere and very likely are influencing the earth's climate.[4] The heating effect caused by the buildup of GHGs in our atmosphere enhances the Earth's natural greenhouse effect and adds to global warming. As global temperatures increase other elements of the climate system, such as precipitation, snow and ice cover, sea levels, and weather events, change. The term ''climate change,'' which encompasses these broader effects, is often used instead of ''global warming.''

According to the IPCC, warming of the climate system is ''unequivocal,'' as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level. Global mean surface temperatures have risen by 0.74 °C (1.3 °F) over the last 100 years. Global mean surface temperature was higher during the last few decades of the 20th century than during any comparable period during the preceding four centuries. U.S. temperatures also warmed during the 20th and into the 21st century; temperatures are now approximately 0.56 °C (1.0 °F) warmer than at the start of the 20th century, with an increased rate of warming over the past 30 years. Most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG concentrations.

According to different scenarios assessed by the IPCC, average global temperature by end of this century is projected to increase by 1.8 to 4.0 °C (3.2 to 7.2 °F) compared to the average temperature in 1990. The uncertainty range of this estimate is 1.1 to 6.4 °C (2.0 to 11.5 °F). Future projections show that, for most scenarios assuming no additional GHG emission reduction policies, atmospheric concentrations of GHGs are expected to continue climbing for most if not all of the remainder of this century, with associated increases in average temperature. Overall risk to human health, society and the environment increases with increases in both the rate and magnitude of climate change.

For additional information about GHGs, climate change, climate science, etc. please see EPA's climate change Web site found at *http://www.epa.gov/climatechange/*.

C. Statutory Authority

On December 26, 2007, President Bush signed the FY2008 Consolidated Appropriations Act which authorized funding for EPA to ''develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of GHG 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 has interpreted that language to confirm that it may be appropriate for the Agency to exercise its CAA authority to require reporting of the quantity of fuel or chemical that is produced or imported from upstream sources such as fuel suppliers, as well as reporting of emissions from facilities (downstream sources) that directly emit GHGs from their processes or from fuel combustion, as appropriate. 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'' under section 821 of the 1990 CAA Amendments.

EPA is proposing this rule under its existing CAA authority. EPA also proposes that the rule require the reporting of the GHG emissions resulting from the quantity 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 from facilities (downstream sources) that directly emit GHGs from their processes or from fuel combustion, as appropriate. This proposed rule would also establish appropriate thresholds and frequency for reporting.

Section 114(a)(1) of the CAA authorizes the Administrator to, *inter alia*, require certain persons (see below) on a one-time, periodic or continuous basis to keep records, make reports, undertake monitoring, sample emissions, or provide such other information as the Administrator may reasonably require. This information may be required of any person who (i) owns or operates an emission source, (ii) manufactures control or process equipment, (iii) the Administrator believes may have information necessary for the purposes set forth in this section, or (iv) is subject to any requirement of the Act (except for manufacturers subject to certain title II requirements). The information may be required for the purposes of developing an implementation plan, an emission standard under sections 111, 112 or 129, determining if any person is in violation of any standard or requirement of an implementation plan or emissions standard, or ''carrying out any provision'' of the Act (except for a provision of title II with respect to manufacturers of new motor vehicles or new motor vehicle engines).[5] 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.

The scope of the persons potentially subject to a section 114(a)(1) information request (e.g., a person ''who the Administrator believes may have information necessary for the purposes set forth in'' section 114(a)) and the reach of the phrase ''carrying out any provision'' of the Act are quite broad. EPA's authority to request information reaches to a source not subject to the CAA, and may be used for purposes relevant to any provision of the Act. Thus, for example, utilizing sections 114 and 208, EPA could gather information relevant to carrying out provisions involving research (e.g., section 103(g)); evaluating and setting standards (e.g., section 111); and endangerment determinations contained in specific provisions of the Act (e.g., 202); as well as other programs.

Given the broad scope of sections 114 and 208 of the CAA, it is appropriate for EPA to gather the information required by this rule because such information is relevant to EPA's carrying out a wide variety of CAA provisions. For example, emissions from direct emitters should inform decisions about whether and how to use section 111 to establish NSPS for various source categories emitting GHGs, including whether there are any additional categories of sources that should be listed under section 111(b). Similarly, the information required of manufacturers of mobile

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[4] IPCCC: Climate Change 2007: The Physical Science Basis, February 2, 2007 (*http://www.ipcc.ch/*).

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

sources should support decisions regarding treatment of those sources under sections 202, 213 or 231 of the CAA. In addition, the information from fuel suppliers would be relevant in analyzing whether to proceed, and particular options for how to proceed, under section 211(c) regarding fuels, or to inform action concerning downstream sources under a variety of Title I or Title II provisions. For example, the geographic distribution, production volumes and characteristics of various fuel types and subtypes may also prove useful is setting NSPS or Best Available Control Technology limits for some combustion sources. Transportation distances from fuel sources to end users may be useful in evaluating cost effectiveness of various fuel choices, increases in transportation emissions that may be associated with various fuel choices, as well as the overall impact on energy usage and availability. The data overall also would inform EPA's implementation of section 103(g) of the CAA regarding improvements in nonregulatory strategies and technologies for preventing or reducing air pollutants. This section, which specifically mentions CO_2, highlights energy conservation, end-use efficiency and fuel-switching as possible strategies for consideration and the type of information collected under this rule would be relevant. The above discussion is not a comprehensive listing of all the possible ways the information collected under this rule could assist EPA in carrying out any provision of the CAA. Rather it illustrates how the information request fits within the parameters of EPA's CAA authority.

D. Inventory of U.S. GHG Emissions and Sinks

The *Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory)*, prepared by EPA's Office of Atmospheric Programs in coordination with the Office of Transportation and Air Quality, is an impartial, policy-neutral report that tracks annual GHG emissions. The annual report presents historical U.S. emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.

The U.S. submits the Inventory to the Secretariat of the UNFCCC as an annual reporting requirement. The UNFCCC treaty, ratified by the U.S. in 1992, sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The U.S. has submitted the GHG inventory to the United Nations every year since 1993. The annual Inventory is consistent with national inventory data submitted by other UNFCCC Parties, and uses internationally accepted methods for its emission estimates.

In preparing the annual Inventory, EPA leads an interagency team that includes DOE, USDA, DOT, DOD, the State Department, and others. EPA collaborates with hundreds of experts representing more than a dozen Federal agencies, academic institutions, industry associations, consultants, and environmental organizations. The Inventory is peer-reviewed annually by domestic experts, undergoes a 30-day public comment period, and is also peer-reviewed annually by UNFCCC review teams.

The most recent GHG inventory submitted to the UNFCCC, the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006* (April 2008), estimated that total U.S. GHG emissions were 7,054.2 million metric tons of CO_2e in 2006. Overall emissions have grown by 15 percent from 1990 to 2006. CO_2 emissions have increased by 18 percent since 1990. CH_4 emissions have decreased by 8 percent since 1990, while N_2O emissions have decreased by 4 percent since 1990. Emissions of HFCs, PFCs, and SF_6 have increased by 64 percent since 1990. The combustion of fossil fuels (i.e., petroleum, coal, and natural gas) was the largest source of GHG emissions in the U.S., and accounted for approximately 80 percent of total CO_2e emissions.

The Inventory is a comprehensive top-down national assessment of national GHG emissions, and it uses top-down national energy data and other national statistics (e.g., on agriculture). To achieve the goal of comprehensive national emissions coverage for reporting under the UNFCCC, most GHG emissions in the report are calculated via activity data from national-level databases, statistics, and surveys. The use of the aggregated national data means that the national emissions estimates are not broken-down at the geographic or facility level. In contrast, this reporting rule focuses on bottom-up data and individual sources above appropriate thresholds. Although it would provide more specific data, it would not provide full coverage of total annual U.S. GHG emissions, as is required in the development of the Inventory in reporting to the UNFCCC.

The mandatory GHG reporting rule would help to improve the development of future national inventories for particular source categories or sectors by advancing the understanding of emission processes and monitoring methodologies. Facility, unit, and process level GHG emissions data for industrial sources would improve the accuracy of the Inventory by confirming the national statistics and emission estimation methodologies used to develop the top-down inventory. The results can indicate shortcomings in the national statistics and identify where adjustments may be needed.

Therefore, although the data collected under this rule would not replace the system in place to produce the comprehensive annual national Inventory, it can serve as a useful tool to better improve the accuracy of future national-level inventories.

At the same time, EPA solicits comment on whether the submission of the Inventory to the UNFCCC could be utilized to satisfy the requirements of the rule promulgated by EPA pursuant to the FY2008 Consolidated Appropriations Act.

For more information about the Inventory, please refer to the following Web site: *http://www.epa.gov/climatechange/emissions/usinventoryreport.html.*

E. How does this proposal relate to U.S. government and other climate change efforts?

The proposed mandatory GHG reporting program would provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions. Accurate and timely information on GHG emissions is essential for informing some future climate change policy decisions. Although additional data collection (e.g., for other source categories such as indirect emissions or offsets) may be required as the development of climate policies evolves, the data collected in this rule would provide useful information for a variety of policies. For example, through data collected under this rule, EPA would 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 would also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions. In addition, the data collected on some source categories such as landfills and manure management, which can be covered by the CAA, could also potentially help inform offset program design by providing fundamental data on current baseline emissions for these categories.

Through this rulemaking, EPA would 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 would also improve the U.S. government's ability to formulate a set of climate change policy options and to assess which industries would be affected, and how these industries would be affected by the options. 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 reduction opportunities and carry them out.

The goal is to have this GHG reporting program supplement and complement, rather than duplicate, U.S. government and other GHG programs (*e.g.*, State and Regional based programs). As discussed in Section I.D of this preamble, EPA anticipates that facility-level GHG emissions data would lead to improvements in the quality of the Inventory.

As discussed in Section II of this preamble, 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). Because this mandatory reporting program would have much broader coverage than the voluntary programs, it would help EPA learn more about emissions from facilities not currently included in these programs and broaden coverage of these industries.

Also discussed in Section II of this preamble, DOE EIA implements a voluntary GHG registry under section 1605(b) of the Energy Policy Act. 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.[6] EPA's proposed mandatory GHG program would have a much broader set of reporters included, primarily at the facility[7] rather than entity-level, but this proposed rule is not designed with the specific intent of reporting of emission reductions, as is the 1605(b) program.

Again, in Section II, existing State and Regional GHG reporting and reduction programs are summarized. Many of those programs may be broader in scope and more aggressive in implementation. States collecting that additional information may have determined that types of data not collected by this proposal are necessary to implement a variety of climate efforts. While EPA's proposal was specifically developed in response to the Appropriations Act, we also acknowledge, similar to the States, there may be a need to collect additional data from sources subject to this rule as well as other sources depending on the types of policies the Agency is developing and implementing (*e.g.*, indirect emissions and offsets). Addressing climate change may require a suite of policies and programs and this proposal for a mandatory reporting program is just one effort to collect information necessary to inform those policies. There may well be subsequent efforts depending on future policy direction and/or requests from Congress.

F. How does this proposal relate to EPA's Climate Change ANPR?

On July 30, 2008, EPA published an ANPR on ''Regulating Greenhouse Gas Emissions under the Clean Air Act'' (73 FR 44354). The ANPR presented information relevant to, and solicited public comment on, issues regarding the potential regulation of GHGs under the CAA, including EPA's response to the U.S. Supreme Court's decision in *Massachusetts* v. *EPA*. 127 S.Ct. 1438 (2007). EPA's proposing the mandatory GHG reporting rule does not indicate that EPA has made any final decisions related to the questions identified in the ANPR. Any information collected under the mandatory GHG reporting program would assist EPA and others in developing future climate policy.[8]

G. How was this proposed rule developed?

In response to the FY2008 Consolidated Appropriations Amendment, EPA has developed this proposed rulemaking. The components of this development are explained in the following subsections.

1. Identifying the Goals of the GHG Reporting System

The mandatory reporting program would provide comprehensive and accurate data which would inform future climate change policies. Potential future 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 we do not know at this time the specific policies that may be adopted, the data reported through the mandatory reporting system should be of sufficient quality to support a range of approaches. Also, consistent with the Appropriations Act, the reporting rule proposes to cover a broad range of sectors of the economy.

To these ends, we identified the following goals of the mandatory reporting system:

- Obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations.
- Balance the rule coverage to maximize the amount of emissions reported while excluding small emitters.
- Create reporting requirements that are consistent with existing GHG reporting programs by using existing GHG emission estimation and reporting methodologies to reduce reporting burden, where feasible.

2. Developing the Proposed Rule

In order to ensure a comprehensive consideration of GHG emissions, EPA organized the development of the proposal around seven categories of processes that emit GHGs: Downstream sources of emissions: (1) Fossil Fuel Combustion: Stationary, (2) Fossil Fuel Combustion: Mobile, (3) Industrial Processes, (4) Fossil Fuel Fugitive[9] Emissions, (5) Biological Processes and Upstream sources of emissions: (6) Fuel

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[6] 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/*)

[7] For the purposes of this proposal, 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.

[8] At this time, a regulation requiring the reporting of GHG emissions and emissions-related data under CAA sections 114 and 208 does not trigger the need for EPA to develop or revise regulations under any other section of the CAA, including the PSD program. See memorandum entitled ''EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program'' (Dec. 18, 2008). EPA is reconsidering this memorandum and will be seeking public comment on the issues raised in it. That proceeding, not this rulemaking, would be the appropriate venue for submitting comments on the issue of whether monitoring regulations under the CAA should trigger the PSD program.

[9] The term ''fugitive'' often refers to emissions that cannot reasonably pass through a stack, chimney, vent or other functionally equivalent opening. This definition of fugitives is used throughout the preamble, except in Section W Oil and Natural Gas Systems, which uses a slightly modified definition based on the Intergovernmental Panel on Climate Change.

Suppliers, and (7) Industrial GHG Suppliers.

For each category, EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes.

3. Evaluation of Existing GHG Reporting Programs

A number of State and regional GHG reporting systems currently are in place or under development. EPA's goal is to develop a reporting rule that, to the extent possible and appropriate, would rely on similar protocols and formats of the existing programs and, therefore, reduce the burden of reporting for all parties involved. Therefore, each of the work groups performed a comprehensive review of existing voluntary and mandatory GHG reporting programs, as well as guidance documents for quantifying GHG emissions from specific sources. These GHG reporting programs and guidance documents included the following:

- International programs, including the IPCC, the EU Emissions Trading System, and the Environment Canada reporting rule;
- U.S. national programs, such as the U.S. GHG inventory, the ARP, voluntary GHG partnership programs (*e.g.*, Natural Gas STAR), and the DOE 1605(b) voluntary GHG registry;
- State and regional GHG reporting programs, such as TCR, RGGI, and programs in California, New Mexico, and New Jersey;
- Reporting protocols developed by nongovernmental organizations, such as WRI/WBCSD; and
- Programs from industrial trade organizations, such as the American Petroleum Institute's Compendium of GHG Estimation Methodologies for the Oil and Gas Industry and the Cement Sustainability Initiative's CO_2 Accounting and Reporting Standard for the Cement Industry, developed by WBCSD.

In reviewing these programs, we analyzed the sectors covered, thresholds for reporting, approach to indirect emissions reporting, the monitoring or emission estimating methods used, the measures to assure the quality of the reported data, the point of monitoring, data input needs, and information required to be reported and/or retained. We analyzed these provisions for suitability to a mandatory, Federal GHG reporting program, and compiled the information. The full review of existing GHG reporting programs and guidance may be found in the docket at EPA–HQ–OAR–2008–0508–054. Section II of this preamble summarizes the fundamental elements of these programs.

4. Stakeholder Outreach To Identify Reporting Issues

Early in the development process, we conducted a proactive communications outreach program to inform the public about the rule development effort. We solicited input and maintained an open door policy for those interested in discussing the rulemaking. Since January 2008, EPA staff held more than 100 meetings with over 250 stakeholders. These stakeholders included:

- Trade associations and firms in potentially affected industries/sectors;
- State, local, and Tribal environmental control agencies and regional air quality planning organizations;
- State and regional organizations already involved in GHG emissions reporting, such as TCR, CARB, and WCI;
- Environmental groups and other nongovernmental organizations.
- We also met with DOE and USDA which have programs relevant to GHG emissions.

During the meetings, we shared information about the statutory requirements and timetable for developing a rule. Stakeholders were encouraged to provide input on key issues. Examples of topics discussed were, existing GHG monitoring and reporting programs and lessons learned, thresholds for reporting, schedule for reporting, scope of reporting, handling of confidential data, data verification, and the role of States in administering the program. As needed, the technical work groups followed up with these stakeholder groups on a variety of methodological, technical, and policy issues. EPA staff also provided information to Tribes through conference calls with different Indian working groups and organizations at EPA and through individual calls with Tribal board members of TCR.

For a full list of organizations EPA met with during development of this proposal, see the memo found at EPA–HQ–OAR–2008–0508–055.

II. Summary of Existing Federal, State, and Regional Emission Reporting Programs

A number of voluntary and mandatory GHG programs already exist or are being developed at the State, Regional, and Federal levels. These programs have different scopes and purposes. Many focus on GHG emission reduction, whereas others are purely reporting programs. In addition to the GHG programs, other Federal emission reporting programs and emission inventories are relevant to the proposed GHG reporting rule. Several of these programs are summarized in this section.

In developing the proposed rule, we carefully reviewed the existing reporting programs, particularly with respect to emissions sources covered, thresholds, monitoring methods, frequency of reporting and verification. States may have, or intend to develop, reporting programs that are broader in scope or are more aggressive in implementation because those programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific complementary measures (e.g., energy efficiency). EPA has benefitted from the leadership the States have shown in developing these programs and their experiences. Discussions with States that have already implemented programs have been especially instructive. Where possible, we built upon concepts in existing Federal and State programs in developing the mandatory GHG reporting rule.

A. Federal Voluntary GHG Programs

EPA and other Federal agencies operate a number of voluntary GHG reporting and reduction programs that EPA reviewed when developing this proposal, including Climate Leaders, several Non-CO_2 voluntary programs, the CHP partnership, the SmartWay Transport Partnership program, the National Environmental Performance Track Partnership, and the DOE 1605(b) voluntary GHG registry. There are several other Federal voluntary programs to encourage emissions reductions, clean energy, or energy efficiency, and this summary does not cover them all. This summary focuses on programs that include voluntary GHG emission inventories or reporting of GHG emission reduction activities for sectors covered by this proposed rulemaking.

Climate Leaders.[10] Climate Leaders is an EPA partnership program that works with companies to develop GHG reduction strategies. Over 250 industry partners in a wide range of sectors have joined. Partner companies complete a corporate-wide inventory of GHG emissions and develop an inventory management plan using Climate Leaders protocols. Each company sets GHG reductions goals and submits to EPA an

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[10] For more information about the Climate Leaders program please see: *http://www.epa.gov/climateleaders/*.

annual GHG emissions inventory documenting their progress. The annual reporting form provides corporate-wide emissions by type of emissions source.

Non-CO_2 Voluntary Partnership Programs.[11] Since the 1990s, EPA has operated a number of non-CO_2 voluntary partnership programs aimed at reducing emissions from GHGs such as CH_4, SF_{66}, and PFCs. There are four sector-specific voluntary CH_4 reduction programs: Natural Gas STAR, Landfill Methane Outreach Program, Coalbed Methane Outreach Program and AgSTAR. In addition, there are sector-specific voluntary emission reduction partnerships for high GWP gases. The Natural Gas STAR partnership encourages companies across the natural gas and oil industries to adopt practices that reduce CH_4 emissions. The Landfill Methane Outreach Program and Coalbed Methane Outreach Program encourage voluntary capture and use of landfill and coal mine CH_4, respectively, to generate electricity or other useful energy. These partnerships focus on achieving CH_4 reductions. Industry partners voluntarily provide technical information on projects they undertake to reduce CH_4 emissions on an annual basis, but they do not submit CH_4 emissions inventories. AgSTAR encourages beneficial use of agricultural CH_4 but does not have partner reporting requirements.

There are two sector specific partnerships to reduce SF_6 emissions: The SF_6 Emission Reduction Partnership for Electric Power Systems, with over 80 participating utilities, and an SF_6 Emission Reduction Partnership for the Magnesium Industry. Partners in these programs implement practices to reduce SF_6 emissions and prepare corporate-wide annual inventories of SF_6 emissions using protocols and reporting tools developed by EPA. There are also two partnerships focused on PFCs. The Voluntary Aluminum Industrial Partnership promotes technically feasible and cost effective actions to reduce PFC emissions. Industry partners track and report PFC emissions reductions. Similarly, the Semiconductor Industry Association and EPA formed a partnership to reduce PFC emissions. A third party compiles data from participating semiconductor companies and submits an aggregate (not company-specific) annual PFC emissions report.

CHP Partnership.[12] The CHP Partnership is an EPA partnership that cuts across sectors. It encourages use of CHP technologies to generate electricity and heat from the same fuel source, thereby increasing energy efficiency and reducing GHG emissions from fuel combustion. Corporate and institutional partners provide data on existing and new CHP projects, but do not submit emissions inventories.

SmartWay Transport Partnership.[13] The SmartWay Transport Partnership program is a voluntary partnership between freight industry stakeholders and EPA to promote fuel efficiency improvements and GHG emissions reductions. Over 900 companies have joined including freight carriers (railroads and trucking fleets) and shipping companies. Carrier and shipping companies commit to measuring and improving the efficiency of their freight operations using EPA-developed tools that quantify the benefits of a number of fuel-saving strategies. Companies report progress annually. The GHG data that carrier companies report to EPA is discussed further in Section V.QQ.4b of this preamble.

National Environmental Performance Track Partnership.[14] The Performance Track Partnership is a voluntary partnership that recognizes and rewards private and public facilities that demonstrate strong environmental performance beyond current requirements. Performance Track is designed to augment the existing regulatory system by creating incentives for facilities to achieve environmental results beyond those required by law. To qualify, applicants must have implemented an independently-assessed environmental management system, have a record of sustained compliance with environmental laws and regulations, commit to achieving measurable environmental results that go beyond compliance, and provide information to the local community on their environmental activities. Members are subject to the same legal requirements as other regulated facilities. In some cases, EPA and states have reduced routine reporting or given some flexibility to program members in how they meet regulatory requirements. This approach is recognized by more than 20 states that have adopted similar performance-based leadership programs.

1605(b) Voluntary Registry.[15] The DOE EIA established a voluntary GHG registry under section 1605(b) of the Energy Policy Act of 1992. The program was recently enhanced and a final rule containing general reporting guidelines was published on April 21, 2006 (71 FR 20784). The rule is contained in 10 CFR part 300. Unlike EPA's proposal which requires of reporting of GHG emissions from facilities over a specific threshold, the DOE 1605(b) registry allows anyone (e.g., a public entity, private company, or an individual) to report on their emissions and their emission reduction projects to the registry. Large emitters (e.g., anyone that emits over 10,000 tons of CO_2e per year) that wish to register emissions reductions must submit annual company-wide GHG emissions inventories following technical guidelines published by DOE and must calculate and report net GHG emissions reductions. The program offers a range of reporting methodologies from stringent direct measurement to simplified calculations using default factors and allows the reporters to report using the methodological option they choose. In addition, as mentioned above, unlike EPA's proposal, sequestration and offset projects can also be reported under the 1605(b) program. There is additional flexibility offered to small sources who can choose to limit annual inventories and emission reduction reports to just a single type of activity rather than reporting company-wide GHG emissions, but must still follow the technical guidelines. Reported data are made available on the Web in a public use database.

Summary. These voluntary programs are different in nature from the proposed mandatory GHG emissions reporting rule. Industry participation in the programs and reporting to the programs is entirely voluntary. A small number of sources report, compared to the number of facilities that would likely be affected by the proposed mandatory GHG reporting rule. Most of the EPA voluntary programs do not require reporting of annual emissions data, but are instead intended to encourage GHG reduction projects/activities and track partner's successes in implementing such projects. For the programs that do include annual emissions reporting (e.g., Climate Leaders, DOE 1605(b)) the scope and level of detail are different. For example, Climate Leaders annual reports are generally corporate-wide and do not contain the facility and process-

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[11] For more information about the Non-CO_2 Voluntary Partnership Programs please see: *http://www.epa.gov/nonco2/voluntaryprograms.html.*

[12] For more information about the CHP Partnership please see: *http://www.epa.gov/chp/.*

[13] For more information about SmartWay please see: *http://www.epa.gov/smartway/.*

[14] For more information about Performance Track please see: *http://www.epa.gov/perftrac/index.htm.*

[15] For more information about DOE's 1605(b) programs please see: *http://www.pi.energy.gov/enhancingGHGregistry/.*

level details that would be needed by a mandatory program to verify the accuracy of the emissions reports.

At the same time, aspects of the voluntary programs serve as useful starting points for the mandatory GHG reporting rules. GHG emission calculation principles and protocols have been developed for various types of emission sources by Climate Leaders, the DOE 1605(b) program, and some partnerships such as the SF_6 reduction partnerships and SmartWay. Under these protocols, reporting companies monitor process or operating parameters to estimate GHG emissions, report annually, and retain records to document their GHG estimates. Through the voluntary programs, EPA, DOE, and participating companies have gained understanding of processes that emit GHGs and experience in developing and reviewing GHG emission inventories.

B. Federal Mandatory Reporting Programs

Sulfur Dioxide (SO_2) and Nitrogen Oxides (NO_X) Trading Programs. The ARP and the NO_X Budget Trading Program are cap-and-trade programs designed to reduce emissions of SO_2 and NO_X[16]. As a part of those programs facilities with EGUs that serve a generator larger than 25 MW are required to report emissions. The 40 CFR part 75 CEMS rule establishes monitoring and reporting requirements under these programs. The regulations in 40 CFR part 75 require continuous monitoring and quarterly and annual emissions reporting of CO_2 mass emissions,[17] SO_2 mass emissions, NO_X emission rate, and heat input. Part 75 contains specifications for the types of monitoring systems that may be used to determine CO_2 emissions and sets forth operations, maintenance, and QA/QC requirement for each system. In some cases, EGUs are allowed to use simplified procedures other than CEMS (e.g., monitoring fuel feed rates and conducting periodic sampling and analyses of fuel carbon content) to determine CO_2 emissions. Under the regulations, affected EGUs must submit detailed quarterly and annual CO_2 emissions reports using standardized electronic reporting formats. If CEMS are used, the quarterly reports include hourly CEMS data and other information used to calculate emissions (e.g., monitor downtime). If alternative monitoring programs are used, detailed data used to calculate CO_2 emissions must be reported.

The joint explanatory statement accompanying the FY2008 Consolidated Appropriations Amendment specified that EPA could use the existing reporting requirements for electric generating units under section 821 of the 1990 CAA Amendments.[18] As described in Sections V.C. and V.D. of this preamble, because the part 75 regulations already require reporting of high quality CO_2 data from EGUs, the GHG reporting rule proposes to use the same CO_2 data rather than require additional reporting of CO_2 from EGUs. They would, however, have to include reporting of the other GHG emissions, such as CH_4 and N_2O, at their facilities.

TRI. TRI requires facility-level reporting of annual mass emissions of approximately 650 toxic chemicals.[19] If they are above established thresholds, facilities in a wide range of industries report including manufacturing industries, metal and coal mining, electric utilities, and other industrial sectors. Facilities must submit annual reports of total stack and fugitive emissions of the listed toxic chemicals using a standardized form which can be submitted electronically. No information is reported on the processes and emissions points included in the total emissions. The data reported to TRI are not directly useful for the GHG rule because TRI does not include GHG emissions and does not identify processes or emissions sources. However, the TRI program is similar to the proposed GHG reporting rule in that it requires direct emissions reporting from a large number of facilities (roughly 23,000) across all major industrial sectors. Therefore, EPA reviewed the TRI program for ideas regarding program structure and implementation.

Vehicle Reporting. EPA's existing criteria pollutant emissions certification regulations, as well as the fuel economy testing regulations which EPA administers as part of the CAFE program, require vehicle manufacturers to measure and report CO_2 for essentially all of their light duty vehicles. In addition, many engine manufacturers currently measure CO_2 as an integral part of calculating emissions of criteria pollutants, and some report CO_2 emissions to EPA in some form.

C. EPA Emissions Inventories

U.S. Inventory of Greenhouse Gas Emissions and Sinks. As discussed in Section I.D of this preamble, EPA prepares the *U.S. Inventory of Greenhouse Gas Emissions and Sinks* every year. The details of this Inventory, the methodologies used to calculate emissions and its relationship to this proposal are discussed in Section I.D of this preamble.

NEI. [20] EPA compiles the NEI, a database of air emissions information provided primarily by State and local air agencies and Tribes. The database contains information on stationary and mobile sources that emit criteria air pollutants and their precursors, as well as hazardous air pollutants. Stationary point source emissions that must be inventoried and reported are those that emit over a threshold amount of at least one criteria pollutant. Many States also inventory and report stationary sources that emit amounts below the thresholds for each pollutant. The NEI includes over 60,000 facilities. The information that is required consists of facility identification information; process information detailing the types of air pollution emission sources; air pollution emission estimates (including annual emissions); control devices in place; stack parameters; and location information. The NEI differs from the proposed GHG reporting rule in that the NEI contains no GHG data, and the data are reported primarily by State agencies rather than directly reported by industries.[21] However, in developing the proposed rule, EPA used the NEI to help determine sources that might need to report under the GHG reporting rule. We considered the types of facility, process and activity data reported in NEI to support the emissions data as a possible model for the types of data to be reported under the GHG reporting rule. We also considered systems that could be used to link data reported under the GHG rule with data for the same facilities in the NEI.

D. Regional and State Voluntary Programs for GHG Emissions Reporting

A number of States have demonstrated leadership and developed corporate voluntary GHG reporting programs individually or joined with other States to develop GHG reporting programs as part of their approaches to addressing GHG emissions. EPA has

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[16] For more information about these cap and trade programs see *http://www.epa.gov/airmarkt/.*

[17] The requirements regarding CO_2 emissions reporting apply only to ARP sources and are pursuant to section 821 of the CAA Amendments of 1990, Public Law 101–549.

[18] The joint explanatory statement refers to "Section 821 of the Clean Air Act" but section 821 was part of the 1990 CAA Amendments not codified into the CAA itself.

[19] For more information about TRI and what chemicals are on the list, please see: *http://www.epa.gov/tri/.*

[20] For more information about the NEI please see: *http://www.epa.gov/ttn/chief/net/.*

[21] As discussed in section IV of the preamble, tropospheric ozone (O_3) is a GHG. The precursors to tropospheric O_3 (e.g., NOX, VOCs, etc) are reported to the NEI by States and then EPA models tropospheric O_3 based on that precursor data.

benefitted from this leadership and the States' experiences; discussions with those that have already implemented programs have been especially instructive. Section V of the preamble describes the proposed methods for each source category. The different options considered have been particularly informed by the States' expertise. This section of the preamble summarizes two prominent voluntary efforts. In developing the greenhouse rules, EPA reviewed the relevant protocols used by these programs as a starting point. We recognize that these programs may have additional monitoring and reporting requirements than those outlined in the proposed rule in order to provide distinct program benefits.

CCAR.[22] CCAR is a voluntary GHG registry already in use in California. CCAR has released several methodology documents including a general reporting protocol, general certification (verification) protocol, and several sector-specific protocols. Companies submit emissions reports using a standardized electronic system. Emission reports may be aggregated at the company level or reported at the facility level.

TCR.[23] TCR is a partnership formed by U.S. and Mexican States, Canadian provinces, and Tribes to develop standard GHG emissions measurement and verification protocols and a reporting system capable of supporting mandatory or voluntary GHG emission reporting rules and policies for its member States. TCR has released a General Reporting Protocol that contains procedures to measure and calculate GHG emissions from a wide range of source categories. They have also released a general verification protocol, and an electronic reporting system. Founding reporters (companies and other organizations that have agreed to voluntarily report their GHG emissions) implemented a pilot reporting program in 2008. Annual reports would be submitted covering six GHGs. Corporations must report facility-specific emissions, broken out by type of emission source (e.g., stationary combustion, electricity use, direct process emissions) within the facility.

E. State and Regional Mandatory Programs for GHG Emissions Reporting and Reduction

Several individual States and regional groups of States have demonstrated leadership and are developing or have developed mandatory GHG reporting programs and GHG emissions control programs. This section of the preamble summarizes two regional cap-and-trade programs and several State mandatory reporting rules. We recognize that, like the current voluntary regional and State programs, State and regional mandatory reporting programs may evolve or develop to include additional monitoring and reporting requirements than those included in the proposed rule. In fact, these programs may be broader in scope or more aggressive in implementation because the programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific complementary measures (e.g., energy efficiency).

RGGI.[24] RGGI is a regional cap-and-trade program that covers CO_2 emissions from EGUs that serve a generator greater than 25 MW in member States in the mid-Atlantic and Northeast. The program goal is to reduce CO_2 emissions to 10 percent below 1990 levels by the year 2020. RGGI will utilize the CO_2 reported to and verified by EPA under 40 CFR part 75 to determine compliance of the EGUs in the cap-and-trade program. In addition, the EGUs in RGGI that are not currently reporting to EPA under the ARP and NOX Budget program (e.g., co-generation facilities) will start reporting their CO_2 data to EPA for QA/QC, similar to the sources already reporting. Certain types of offset projects will be allowed, and GHG offset protocols have been developed. The States participating in RGGI have adopted State rules (based on the model rule) to implement RGGI in each State. The RGGI cap-and-trade program took effect on January 1, 2009.

WCI.[25] WCI is another regional cap-and-trade program being developed by a group of Western States and Canadian provinces. The goal is to reduce GHG emissions to 15 percent below 2005 levels by the year 2020. Draft options papers and program scope papers were released in early 2008, public comments were reviewed, and final program design recommendations were made in September 2008. Other elements of the program, such as reporting requirements, market operations, and offset program development continues. Several source categories are being considered for inclusion in the cap and trade framework. The program might be phased in, starting with a few source categories and adding others over time. Points of regulation for some source categories, calculation methodologies, and other reporting program elements are under development. The WCI is also analyzing alternative or complementary policies other than cap-and-trade that could help reach GHG reduction goals. Options for rule implementation and for coordination with other rules and programs such as TCR are being investigated.

A key difference between the Federal mandatory GHG reporting rule and the RGGI and WCI programs is that the Federal mandatory GHG rule is solely a reporting requirement. It does not in any way regulate GHG emissions or require any emissions reductions.

State Mandatory GHG Reporting Rules. Seventeen States have developed, or are developing, mandatory GHG reporting rules.[26] The docket contains a summary of these State mandatory rules (EPA–HQ–OAR–2008–0508–056). Final rules have not yet been developed by some of the States, so details of some programs are unknown. Reporting requirements have taken effect in twelve States as of 2009; the rest start between 2010 and 2012. Reporting is typically annual, although some States require quarterly reporting for EGUs, consistent with RGGI and the ARP.

State rules differ with regard to which facilities must report and which GHGs must be reported. Some States require all facilities that must obtain Title V permits to report GHG emissions. Others require reporting for particular sectors (e.g., large EGUs, cement plants, refineries). Some State rules apply to any facility with stationary combustion sources that emit a threshold level of CO_2. Some apply to any facility, or to facilities within listed industries, if their emissions exceed a specified threshold level of CO_2e. Many of the State rules apply to six GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6); others apply only to CO_2 or a subset of the six gases. Most require reporting at the facility level, or by unit or process within a facility.

The level of specificity regarding GHG monitoring and calculation methods varies. Some of the States refer to use of protocols established by TCR or CCAR. Others look to industry-specific protocols (such as methods developed by the American Petroleum Institute), to accepted international methodologies such as IPCC, and/or to emission factors in EPA's Compilation of Air Pollutant

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[22] For more information about CCAR please see: *http://www.climateregistry.org/*.

[23] For more information about TCR please see: *http://www.theclimateregistry.org/*.

[24] For more information about RGGI please see: *http://www.rggi.org/*.

[25] For more information about WCI please see: *http://www.westernclimateinitiative.org/*.

[26] These include: California, Colorado, Connecticut, Delaware, Hawaii, Iowa, Maine, Maryland, Massachusetts, New Jersey, New Mexico, North Carolina, Oregon, Virginia, Washington, West Virginia, and Wisconsin.

Emission Factors (known as AP–42[27]) or other EPA guidance.

California Mandatory GHG Reporting Rule.[28] CARB's mandatory reporting rule is an example of a State rule that covers multiple source categories and contains relatively detailed requirements, similar to this proposal developed by EPA. According to the CARB proposed rule (originally proposed October 19, 2007, and revised on December 5, 2007), monitoring must start on January 1, 2009, and the first reports will be submitted in 2010. The rule requires facility-level reporting of all GHGs, except PFCs, from cement manufacturing plants, electric power generation and retail, cogeneration plants, petroleum refineries, hydrogen plants, and facilities with stationary combustion sources emitting greater than 25,000 tons CO_2 per year. California requires 40 CFR part 75 data for EGUs. The California rule contains specific GHG estimation methods that are largely consistent with CCAR protocols, and also rely on American Petroleum Institute protocols and IPCC/EU protocols for certain types of sources. California continues to participate in other national and regional efforts, such as TCR and WCI, to assist with developing consistent reporting tools and procedures on a national and regional basis.

F. How the Proposed Mandatory GHG Reporting Program Is Different From the Federal and State Programs EPA Reviewed

The various existing State and Federal programs EPA reviewed are diverse. They apply to different industries, have different thresholds, require different pollutants and different types of emissions sources to be reported, rely on different monitoring protocols, and require different types of data to be reported, depending on the purposes of each program. None of the existing programs require nationwide, mandatory GHG reporting by facilities in a large number of sectors, so EPA's proposed mandatory GHG rule development effort is unique in this regard.

Although the mandatory GHG rule is unique, EPA carefully considered other Federal and State programs during development of the proposed rule. Documentation of our review of GHG monitoring protocols for each source category used by Federal, State, and international voluntary and mandatory GHG programs, and our review of State mandatory GHG rules can be found at EPA–HQ–OAR–2008–0508–056. The proposed monitoring and GHG calculation methodologies for many source categories are the same as, or similar to, the methodologies contained in State reporting programs such as TCR, CCAR, and State mandatory GHG reporting rules and similar to methodologies developed by EPA voluntary programs such as Climate Leaders. The reporting requirements set forth in 40 CFR part 75 are also being used for this proposed rule. Similarity in proposed methods would help maximize the ability of individual reporters to submit the emissions calculations to multiple programs, if desired. EPA also continues to work closely with States and State-based groups to ensure that the data management approach in this proposal would lead to efficient submission of data to multiple programs. Section V of this preamble includes further information on the selection of monitoring methods for each source category.

The intent of this proposed rule is to collect accurate and consistent GHG emissions data that can be used to inform future decisions. One goal in developing the rule is to utilize and be consistent with the GHG protocols and requirements of other State and Federal programs, where appropriate, to make use of existing cooperative efforts and reduce the burden to facilities submitting reports to other programs. However, we also need to be sure the mandatory reporting rule collects facility-specific data of sufficient quality to achieve the Agency's objectives for this rule. Therefore, some reporting requirements of this proposed rule are different from the State programs. The remaining sections of this preamble further describe the proposed rule requirements and EPA's rationale for all of the requirements.

EPA seeks comment on whether the conclusions drawn during its review of existing programs are accurate and invites data to demonstrate if, and if so how, the goals and objectives of this proposed mandatory reporting system could be met through existing programs. In particular, comments should address how existing programs meet the breadth of sources reporting, thresholds for reporting, consistency and stringency of methods for reporting, level of reporting, frequency of reporting and verification of reports included in this proposal.

III. Summary of the General Requirements of the Proposed Rule

The proposed rule would require reporting of annual emissions of CO_2, CH_4, N_2O, SF_6, HFCs, PFCs, and other fluorinated gases (as defined in proposed 40 CFR part 98, subpart A). The rule would apply to certain downstream facilities that emit GHGs, upstream suppliers of fossil fuels and industrial GHGs, and manufacturers of vehicles and engines.[29] We are proposing that reporting be at the facility[30] level, except that certain suppliers of fossil fuels and industrial gases and manufacturers of vehicles and engines would report at the corporate level.

A. Who must report?

Owners and operators of the following facilities and supply operations would submit annual GHG emission reports under the proposal:

- A facility that contains any of the source categories listed below in any calendar year starting in 2010. For these facilities, the GHG emission report would cover all sources in any source category for which calculation methodologies are provided in proposed 40 CFR part 98, subparts B through JJ.
  - —Electricity generating facilities that are subject to the ARP, or that contain electric generating units that collectively emit 25,000 metric tons of CO_2e or more per year.[31]
  - —Adipic acid production.
  - —Aluminum production.
  - —Ammonia manufacturing.
  - —Cement production.
  - —Electronics—Semiconductor, MEMS, and LCD (LCD) manufacturing facilities with an annual production capacity that exceeds any of the thresholds listed in this paragraph—Semiconductors:

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[27] See Compilation of Air Pollutant Emission Factors, Fifth Edition: *http://www.epa.gov/ttn/chief/ap42/index.html_ac/index.html.*

[28] For more information about CA mandatory reporting program please see: *http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.*

[29] We are proposing to incorporate the reporting requirements for manufacturers of motor vehicles and engines into the existing reporting requirements of 40 CFR parts 86, 89, 90, 91, 92, 94, 1033, 1039, 1042, 1045, 1048, 1051, and 1054.

[30] For the purposes of this proposal, 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.

[31] This does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. As described in section V.C of the preamble we are taking comment on whether or not a permit should be required.

1,080 m^2 silicon, MEMS: 1,202 m^2 silicon, LCD: 235,700 m^2 LCD.
—Electric power systems that include electrical equipment with a total nameplace capacity that exceeds 17,820 lbs (7,838 kg) of SF_6 or PFCs.
—HCFC–22 production.
—HFC–23 destruction processes that are not colocated 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.
—Phosphoric acid production.
—Silicon carbide production.
—Soda ash production.
—Titanium dioxide production.
—Underground coal mines that are subject to quarterly or more frequent sampling by MSHA of ventilation systems.
—Municipal landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year.
—Manure management systems that emit CH_4 and N_2O in amounts equivalent to 25,000 metric tons CO_2e or more per year.

- Any facility 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 below that are located at the facility in any calendar year starting in 2010. For these facilities, the GHG emission report would cover all source categories for which calculation methodologies are provided in proposed 40 CFR part 98, subparts B through JJ of the rule.

—Electricity Generation[32]
—Electronics—Photovoltaic Manufacturing
—Ethanol Production
—Ferroalloy Production
—Fluorinated Greenhouse Gas Production
—Food Processing
—Glass Production
—Hydrogen Production
—Iron and Steel Production
—Lead Production
—Magnesium Production
—Oil and Natural Gas Systems
—Pulp and Paper Manufacturing
—Zinc Production
—Industrial Landfills
—Wastewater

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

—The facility does not contain any source in any source category designated in the above two paragraphs;
—The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater; and
—The facility emits 25,000 metric tons CO_2e or more per year from all stationary fuel combustion sources.[33]

- Any supplier of any of the products listed below in any calendar year starting in 2010. For these suppliers, the GHG emissions report would cover all applicable products for which calculation methodologies are provided in proposed 40 CFR part 98, subparts KK through PP.

—Coal.
—Coal-based liquid fuels.
—Petroleum products.
—Natural gas and NGLs.
—Industrial GHGs: All producers of industrial GHGs, importers and exporters of industrial GHGs with total bulk imports or total bulk exports that exceed 25,000 metric tons CO_2e per year.
—CO_2: All producers of CO_2, importers and exporters of CO_2 or a combination of CO_2 and other industrial GHGs with total bulk imports or total bulk exports that exceed 25,000 metric tons CO_2e per year.

- Manufacturers of mobile sources and engines would be required to report emissions from the vehicles and engines they produce, generally in terms of an emission rate.[34] These requirements would apply to emissions of CO_2, CH_4, N_2O, and, where appropriate, HFCs. Manufacturers of the following vehicle and engine types would need to report: (1) Manufacturers of passenger cars, light trucks, and medium-duty passenger vehicles, (2) manufacturers of highway heavy-duty engines and complete vehicles, (3) manufacturers of nonroad diesel engines and nonroad large spark-ignition engines, (4) manufacturers of nonroad small spark-ignition engines, marine spark-ignition engines, personal watercraft, highway motorcycles, and recreational engines and vehicles, (5) manufacturers of locomotive and marine diesel engines, and (6) manufacturers of jet and turboprop aircraft engines.

B. Schedule for Reporting

Facilities and suppliers would begin collecting data on January 1, 2010. The first emissions report would be due on March 31, 2011, for emissions during 2010.[35] [36] Reports would be submitted annually. Facilities with EGUs that are subject to the ARP would continue to report CO_2 mass emissions quarterly, as required by the ARP, in addition to providing the annual GHG emissions reports under this rule. EPA is proposing that the rule require the submission of GHG emissions data on an ongoing, annual basis. The snapshot of information provided by a one-time information collection request would not provide the type of ongoing information which could inform the variety of potential policy options being evaluated for addressing climate change. EPA is taking comment on other possible options, including a commitment to review the continued need for the information at a specific later date, or a sunset provision. Once subject to this reporting rule, a facility or supply operation would continue to submit reports even if it falls below the reporting thresholds in future years.

C. What do I have to report?

The report would include total annual GHG emissions in metric tons of CO_2e aggregated for all the source categories and for all supply categories for which emission calculation methods are provided in part 98. The report would also separately present annual mass GHG emissions for each source category and supply category, by gas. Separate reporting requirements are provided for vehicle and engine manufacturers. These sources would be required to report emissions from the vehicles and engines they produce, generally in terms of an emission rate.

Within a given source category, the report also would break out emissions at the level required by the respective subpart (e.g., reporting could be

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[32] This does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. As described in section V.C of the preamble we are taking comment on whether or not a permit should be required.

[33] This does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. As described in section V. C of the preamble we are taking comment on whether or not a permit should be required.

[34] As discussed in Section V.QQ, manufacturers below a size threshold would be exempt.

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

[36] There is a discussion in section I.IV of this preamble that takes comment on alternative reporting schedules.

required for each individual unit for some source categories and for each process line for other source categories).

In addition to GHG emissions, you would report certain activity data (e.g., fuel use, feedstock inputs) that were used to generate the emissions data. The required activity data are specified in each subpart. For some source categories, additional data would be reported to support QA/QC and verification.

EPA would 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 cannot be considered CBI.[37]

D. How do I submit the report?

The reports would be submitted electronically, in a format to be specified by the Administrator after publication of the final rule.[38] To the extent practicable, we plan to adapt existing 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 reporting mechanisms.

Each report would contain a signed certification by a Designated Representative of the facility. On behalf of the owner or operator, the Designated Representative would 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, based on a reasonable inquiry of individuals responsible for obtaining the information.

E. What records must I retain?

Each facility or supplier would also have to retain and make available to EPA upon request the following records for five 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;
- Documentation of the process used to collect the necessary data for the GHG emissions calculations;
- The GHG emissions calculations and methods used;
- All emission factors used for the GHG emissions calculations;
- Any facility operating data or process information used for the GHG emissions calculations;
- Names and documentation of key facility personnel involved in calculating and reporting the GHG emissions;
- The annual GHG emissions reports;
- A log book documenting any procedural changes to the GHG emissions accounting methods and any changes to the instrumentation critical to GHG emissions calculations;
- Missing data computations;
- A written QAPP;
- Any other data specified in any applicable subpart of proposed 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.

IV. Rationale for the General Reporting, Recordkeeping and Verification Requirements That Apply to All Source Categories

This section of the preamble explains the rationales for EPA's proposals for various aspects of the rule. This section applies to all of the source categories in the preamble (further discussed in Sections V.B through V.PP of this preamble) with the exception of mobile sources (discussed in Section V.QQ of this preamble). The proposals EPA is making with regard to mobile sources are extensions of existing EPA programs and therefore the rationales and decisions are discussed wholly within that section. With respect to the source categories B through PP, EPA is particularly interested in receiving comments on the following issues:

(1) Reporting thresholds. EPA is interested in receiving data and analyses on thresholds. In particular, we solicit comment on whether the thresholds proposed are appropriate for each source category or whether other emissions or capacity based thresholds should be applied. If suggesting alternative thresholds, please discuss whether and how they would achieve broad emissions coverage and result in a reasonable number of reporters.

(2) Methodologies. EPA is interested in receiving data, technical information and analyses relevant to the methodology approach. We solicit comment on whether the methodologies selected by EPA are appropriate for each source category or whether alternative approaches should be adopted. In particular, EPA would like information on the technical feasibility, costs, and relative improvement in accuracy of direct measurement at facilities. If suggesting an alternative methodology (e.g., using established industry default factors or allowing industry groups to propose an industry specific emission factor to EPA), please discuss whether and how it provides complete and accurate emissions data, comparable to other source categories, and also reflects broadly agreed upon calculation procedures for that source category.

(3) Frequency and year of reporting. EPA is interested in receiving data and analyses regarding frequency of reporting and the schedule for reporting. In particular, we solicit information regarding whether the frequency of data collection and reporting selected by EPA is appropriate for each source category or whether alternative frequencies should be considered (e.g., quarterly or every few years). If suggesting an alternative frequency, please discuss whether and how it ensures that EPA and the public receive the data in a timely fashion that allow it to be relevant for future policy decisions. EPA is proposing 2010 data collection and 2011 reporting, however, we are interested in receiving comment on alternative schedules if we are unable to meet our goal.

(4) Verification. EPA is interested in receiving data and analyses regarding verification options. We solicit input on whether the verification approach selected by EPA is appropriate for each source category or whether an alternative approach should be adopted. If suggesting an alternative verification approach, please discuss how it weighs the costs and burden to the reporter and EPA as well as the need to ensure the data are complete, accurate, and available in the timely fashion.

(5) Duration of the program. EPA is interested in receiving data and analyses regarding options for the duration of the GHG emissions information collection program in this proposed rule. By duration, EPA means for how many years the program should require the submission of information. EPA solicits input on whether the duration selected by EPA is appropriate for each source category or whether an alternative approach should be adopted. If suggesting an alternative duration, please discuss how it impacts the need to ensure the data are sufficient to inform the variety of potential policy decisions regarding climate change under consideration.

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[37] 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).

[38] For more information about the reporting format please see section VI of this preamble.

A. Rationale for Selection of GHGs To Report

The proposed rule would require reporting of CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and other fluorinated compounds (e.g., NF_3 and HFEs) as defined in the rule [39]. These are the most abundantly emitted GHGs that result from human activity. They are not currently controlled by other mandatory Federal programs and, with the exception of the CO_2 emissions data reported by EGUs subject to the ARP [40], GHG emissions data are also not reported under other mandatory Federal programs. CO_2 is the largest contributor of GHGs directly emitted by human activities, and is a significant driver of climate change. The anthropogenic combined heating effect of CH_4, N_2O, HFCs, PFCs, SF_6, and the other fluorinated compounds are also 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 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 the common focus of the climate change research community. The IPCC also included methods for accounting for emissions from several specified fluorinated gases in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[41] These gases include fluorinated ethers, which are used in electronics, anesthetics, and as heat transfer fluids. Like the other six GHGs for which emissions would be reported, these fluorinated compounds are long-lived in the atmosphere and have high GWP. In many cases these fluorinated gases are used in expanding industries (e.g., electronics) or as substitutes for HFCs. As such, EPA is proposing to include 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 proposing to include in this rule: Water vapor, CFCs, HCFCs, halons, tropospheric O_3, and black carbon. There are a number of reasons why we are not proposing to require reporting of these gases and aerosols under this rule. For example, these GHGs and aerosols are not covered under any State or Federal voluntary or mandatory GHG program, the UNFCCC or the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Nonetheless, we request comment on the selection of GHGs that are or are not included in the proposed rule; include data supporting your position on why a GHG should or should not be included. More detailed discussions for particular substances that we do not propose including in this rule follow.

Water Vapor. Water vapor is the most abundant naturally occurring GHG and, therefore, makes up a significant share of the natural, background greenhouse effect. However, water vapor emissions from human activities have only a negligible effect on atmospheric concentrations of water vapor. Significant changes to global atmospheric concentrations of water vapor occur indirectly through human-induced global warming, which then increases the amount of water vapor in the atmosphere because a warmer atmosphere can hold more moisture. Therefore, changes in water vapor concentrations are not an initial driver of climate change, but rather an effect of climate change which then acts as a positive feedback that further enhances warming. For this reason, the IPCC does not list direct emissions of water vapor as an anthropogenic forcing agent of climate change, but does include this water vapor feedback mechanism in response to human-induced warming in all modeling scenarios of future climate change. Based on this recognition that anthropogenic emissions of water vapor are not a significant driver of anthropogenic climate change, EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* does not include water vapor, and GHG inventory reporting guidelines under the UNFCCC do not require data on water vapor emissions.

ODS. The CFCs, HCFCs, and halons are all strong anthropogenic GHGs that are long-lived in the atmosphere and are adding to the global anthropogenic heating effect. Therefore, these gases share common climatic properties with the other GHGs discussed in this preamble. The production and consumption of these substances (and, hence, their anthropogenic emissions) are being controlled and phased out, not because of their effects on climate change, but because they deplete stratospheric O_3, which protects against harmful ultraviolet B radiation. The control and phase-out of these substances in the U.S. and globally is occurring under the Montreal Protocol on Substances that Deplete the Ozone Layer, and in the U.S. under Title VI of the CAA as well.[42] Therefore, the climate change research and policy community typically does not focus on these substances, precisely because they are essentially already being addressed with non-climate policy mechanisms. The UNFCCC does not cover these substances, and instead defers their treatment to the Montreal Protocol.

Tropospheric Ozone. Increased concentrations of tropospheric O_3 are causing a significant anthropogenic warming effect, but, unlike the long-lived GHGs, tropospheric O_3 has a short atmospheric lifetime (hours to weeks), and therefore its concentrations are more variable over space and time. For these reasons, its global heating effect and relevance to climate change tends to entail greater uncertainty compared to the well-mixed, long-lived GHGs. Tropospheric O_3 is not addressed under the UNFCCC. Moreover, tropospheric O_3 is already listed as a NAAQS pollutant and its precursors are reported to States. Tropospheric O_3 is subsequently modeled based on the precursor data reported to the NEI.

Black Carbon. Black carbon is an aerosol particle that results from incomplete combustion of the carbon contained in fossil fuels, and it remains in the atmosphere for about a week. There is some evidence that black carbon emissions may contribute to climate warming by absorbing incoming and reflected sunlight in the atmosphere and by darkening clouds, snow and ice. While the net effect of anthropogenic aerosols has a cooling effect (CCSP 2009), there is considerable uncertainty

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[39] The GWPs for the GHGs to be reported are found in Table A–1 of proposed 40 CFR part 98, subpart A.

[40] Pursuant to regulations established under section 821 of the CAA Amendments of 1990, hourly CO_2 emissions are monitored and reported quarterly to EPA. EPA performs a series of QA/QC checks on the data and then makes it available on the Web site (*http://epa.gov/camddataandmaps/*) usually within 30 days after receipt.

[41] 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).

[42] Under the Montreal Protocol, production and consumption of CFCs were phased out in developed countries in 1996 (with some essential use exemptions) and are scheduled for phase-out by 2010 in developing countries (with some essential use exemptions). For halons the schedule was 1994 for phase out in developed countries and 2010 for developing countries; HCFC production was frozen in 2004 in developed countries, and in 2016 production will be frozen in developing countries; and HCFC consumption phase-out dates are 2030 for developed countries and 2040 in developing countries.

in quantifying the effects of black carbon on radiative forcing and whether black carbon specifically has direct or indirect warming effects. The National Academy of Sciences states ''Regulations targeting black carbon emissions or ozone precursors would have combined benefits for public health and climate'' [43] while also indicating that the level of scientific understanding regarding the effect of black carbon on climate is ''very low.'' The direct and indirect radiative forcing properties of multiple aerosols, including sulphates, organic carbon, and black carbon, are not well understood. While mobile diesel engines have been the largest black carbon source in the U.S., these emissions are expected to be reduced significantly over the next several decades based on CDPFs for new vehicles.

B. Rationale for Selection of Source Categories To Report

Section III of this preamble lists the source categories that would submit reports under the proposed rule. The source categories identified in this list were selected after considering the language of the Appropriations Act and the accompanying explanatory statement, 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.'' [44] In developing the proposed list, we also used our significant experience in quantifying GHG emissions from source categories across the economy for the *Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

As a starting point, EPA first considered all anthropogenic sources of GHG emissions. The term ''anthropogenic'' refers to emissions that are produced as a result of human activities (e.g., combustion of coal in an electric utility or CH_4 emissions from a landfill). This is in contrast to GHGs that are emitted to the atmosphere as a result of natural activities, such as volcanoes. Anthropogenic emissions may be of biogenic origin (manure lagoons) or non-biogenic origin (e.g., coal mines). Consistent with existing international, national, regional, and corporate-level GHG reporting programs, this proposal includes only anthropogenic sources.

As a second step, EPA considered all of the source categories in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* because, as described in Section I.D of this preamble, it is a top-down assessment of anthropogenic sources of emissions in the U.S. Furthermore, the Inventory has been independently reviewed by national and international experts and is considered to be a comprehensive representation of national-level GHG emissions and source categories relevant for the U.S.

As a third step, EPA also carefully reviewed the recently completed 2006 IPCC Guidelines for National Greenhouse Gas Inventories for additional source categories that may be relevant for the U.S. These international guidelines are just beginning to be incorporated into national inventories. The 2006 IPCC Guidelines identified one additional source category for consideration (fugitive emissions from fluorinated GHG production).

As a fourth step, once EPA had a complete list of source categories relevant to the U.S., the Agency systematically reviewed those source categories against the following criteria to develop the list to the source categories included in the proposal:

(1) Include source categories that emit the most significant amounts of GHG emissions, while also minimizing the number of reporters, and

(2) Include source categories that can be measured with an appropriate level of accuracy.

To accomplish the first criterion, EPA set reporting thresholds, as described in Section IV.C of this preamble, that are designed to target large emitters. When the proposed thresholds are applied, the source categories included in this proposal meet the criterion of balancing the emissions coverage with a reasonable number of reporters. For more detailed information about the coverage of emissions and number of reporters see the Thresholds TSD (EPA–HQ–OAR–2008–0508–046) and the RIA (EPA–HQ–OAR–2008–0508–002).

The second criterion was to require reporting for only those sources for which measurement capabilities are sufficiently accurate and consistent. Under this criterion, EPA considered whether or not facility reporting would be as effective as other means of obtaining emissions data. For some sources, our understanding of emissions is limited by lack of knowledge of source-specific factors. In instances where facility-specific calculations are feasible and result in sufficiently accurate and consistent estimates, facility-level reporting would improve current inventory estimates and EPA's understanding of the types and levels of emissions coming from large facilities, particularly in the industrial sector. These source categories have been included in the proposal. For other source categories, uncertainty about emissions is related more to the unavailability of emission factors or simple models to estimate emissions accurately and at a reasonable cost at the facility-level. Under this criterion, we would require facility-level reporting only if reporting would provide more accurate estimates than can be obtained by other means, such as national or regional-level modeling. For an example, please refer to the discussion below on emissions from agricultural sources and other land uses.

As the Agency completed its four step evaluation of source categories to include in the proposal, some source categories were excluded from consideration and some were added. The reasons for the additions and deletions are explained below. In general, the proposed reporting rule covers almost all of the source categories in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* and the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

Reporting by direct emitters. Consistent with the appropriations language regarding reporting of emissions from ''downstream sources,'' EPA is proposing reporting requirements from facilities that directly emit GHGs above a certain threshold as a result of combustion of fuel or processes. The majority of the direct emitters included in this proposal are large facilities in the electricity generation or industrial sectors. In addition, many of the electricity generation facilities are already reporting their CO_2 emissions to EPA under existing regulations. As such, these facilities have only a minimal increase in the amount of data they have to provide EPA on their CH_4 and N_2O emissions. The typical industrial facilities that are required to report under this proposal have emissions that are substantially higher than the proposed thresholds and are already doing many of the measurements and quantifications of emissions required by this proposal through existing business practices, voluntary programs, or mandatory State-level GHG reporting programs.

For more information about the thresholds included in this proposal please refer to Section IV.C of this

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[43] National Academy of Sciences, ''Radiative Forcing of Climate Change: Expanding the Concept and Addressing Uncertainties,'' October 2005.

[44] To read the full appropriations language please refer to the links on this Web site: *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.*

preamble and for more information about the requirements for specific sources refer to Section V of this preamble.

Reporting by fuel and industrial GHG suppliers.[45] Consistent with the appropriations language regarding reporting of emissions from ''upstream production,'' EPA is proposing reporting requirements from upstream suppliers of fossil fuel and industrial GHGs. In the context of GHG reporting, ''upstream emissions'' refers to the GHG emissions potential of a quantity of industrial gas or fossil fuel supplied into the economy. For fossil fuels, the emissions potential is the amount of CO_2 that would be produced from complete combustion or oxidation of the carbon in the fuel. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources, particularly in the commercial and residential sectors (*e.g.*, HFCs emitted from home A/C units or GHG emissions from individual motor vehicles).[46] To cover these direct emissions would require reporting by hundreds or thousands of small facilities. To avoid this impact, the proposed rule does not include all of those emitters, but instead requires reporting by the suppliers of industrial gases and suppliers of fossil fuels. Because the GHGs in these products are almost always fully emitted during use, reporting these supply data would provide an accurate estimate of national emissions while substantially reducing the number of reporters.[47] For this reason, the proposed rule requires reporting by suppliers of coal and coal-based products, petroleum products, natural gas and NGLs, CO_2 gas, and other industrial GHGs. We are not proposing to require reporting by suppliers of biomass-based fuels, or renewable fuels, due to the fact that GHGs emitted upon combustion of these fuels are traditionally taken into account at the point of biomass production. However, we seek comment on this approach and note that producers of some biomass-based fuels (e.g., ethanol) would be subject to reporting requirements for their on-site emissions under this proposal, similar to other fuel producers. For more information about these source categories please see the source-specific discussions in Section V of this preamble.

There is inherent double-reporting of emissions in a program that includes both upstream and downstream sources. For example, coal mines would report CO_2 emissions that would be produced from combustion of the coal supplied into the economy, and the receiving power plants are already reporting CO_2 emissions to EPA from burning the coal to generate electricity. This double-reporting is nevertheless 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. EPA recognizes the double-reporting and as discussed in Section I.D of this preamble does not intend to use the upstream and downstream emissions data as a replacement for the national emissions estimates found in the Inventory.

It is possible to construct a reporting system with no double-reporting. For example, such a system could include fossil fuel combustion-related emissions upstream only, based on the fuel suppliers, supplemented by emissions reported downstream for industrial processes at select industries (e.g., CO_2 process emissions from the production of cement); fugitive emissions from coal, oil, and gas operations; biological processes and mobile source manufacturers. Industrial GHG suppliers could be captured completely upstream, thereby removing reporting obligations from the use of the industrial gases by large downstream users (e.g., magnesium production and SF_6 in electric power systems). Under this option, the total number of facilities affected is approximately 32% lower than the proposed option, and the private sector costs are approximately 26% lower than the proposed option. The emissions coverage remains largely the same as the proposed option although it is important to note that some process related emissions may not be captured due to the fact that downstream combustion sources would not be covered under this option. A source with process emission plus combustion emissions would only have to report their process emission, thus the exclusion of downstream combustion could result in some sources being under the threshold. For more information about this analysis and the differences in the number of reporters and coverage of emissions, please see the RIA (EPA–HQ–OAR–2008–0508–002).

Emissions from agricultural sources and other land uses. The proposed rule does not require reporting of GHG emissions from enteric fermentation, rice cultivation, field burning of agricultural residues, composting (other than as part of a manure management system), agricultural soil management, or other land uses and land-use changes, such as emissions associated with deforestation, and carbon storage in living biomass or harvested wood products. As discussed in Section V of this preamble, the proposal does include reporting of emissions from manure management systems.

EPA reports on the GHG emissions and sinks associated with agricultural and land-use sources in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks.* In the agriculture sector, the U.S. GHG inventory report estimated that agricultural soil management, which includes fertilizer application (including synthetic and manure fertilizers, etc.), contributed N_2O emissions of 265 million metric tons CO_2e in 2006 and enteric fermentation contributed CH_4 emissions of 126 million metric tons CO_2e in 2006. These amounts reflect 3.8 percent and 1.8 percent of total GHG emissions from anthropogenic sources in 2006. Rice cultivation, agricultural field burning, and composting (other than as part of a manure management system) contributed emissions of 5.9, 1.2, and 3.3 million metric tons CO_2e, respectively in 2006. Total carbon fluxes, rather than specific emissions from deforestation, for U.S. forestlands and other land uses and land-use changes were also reported in the U.S. GHG inventory report.

The challenges to including these direct emission source categories in the rule are that practical reporting methods to estimate facility-level emissions for these sources can be difficult to implement and can yield uncertain results. For more information on uncertainty for these sources, please refer to the TSD for Biological Process Sources Excluded from this Rule (EPA–HQ–OAR–2008–0508–045). Furthermore, these sources are characterized by a large number of small emitters. In light of these challenges, we have determined that it is impractical to require reporting of emissions from these sources in the proposed rule at

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[45] In this context, suppliers include producers, importers, and exporters of fossil fuels and industrial GHGs.

[46] While EPA is not proposing any reporting requirements in this rule for operators of mobile source fleets, we are requesting comment in Section V.QQ.4.b of the Preamble.

[47] As an example of estimating the CO_2 emissions that result from the combustion of fossil fuels, please see, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2—Energy, Chapter 1—Introduction (*http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html*).

this time for the reasons explained below.

For these sources, currently, there are no direct greenhouse gas emission measurement methods available except for research methods that are prohibitively expensive and require sophisticated equipment. Instead, 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 using emission factor or carbon stock change approaches, it would be necessary for landowners to report on management practices, and a variety of data inputs. Activity data collection and emission factor development necessary for emissions calculations at the scale of individual reporters can be complex and costly.

For example, for calculating emissions of N_2O from agricultural soils, data on nitrogen inputs necessary for accurate emissions calculations include: Synthetic fertilizer, organic amendments (manure and sludge), waste from grazing animals, crop residues, and mineralization of soil organic matter. While some activity data can be collected with reasonable certainty, the emissions estimates could still have a high degree of uncertainty because the emission factors available for individual reporters do not reflect the variety of conditions (e.g., soil type, moisture) that need to be considered for accurate estimates.

Without reasonably accurate facility-level emissions factors and the ability to accurately measure all facility-level calculation variables at a reasonable cost to reporters, facility-level emissions reporting would not improve our knowledge of GHG emissions relative to national or regional-level emissions models and data available from national databases. While a systematic measurement program of these sources could improve understanding of the environmental factors and management practices that influence emissions, this type of measurement program is technically difficult and expensive to implement, and would be better accomplished through an empirical research program that establishes and maintains rigorous measurements over time.

Despite the issues associated with reporting by the agriculture and land use sectors, threshold analyses were conducted for several source categories within these sectors as part of their consideration for inclusion in this rule. For some agricultural source categories, the number of individual farms covered at various thresholds was estimated. The resulting analyses showed that for most of these sources no facilities would exceed any of the thresholds evaluated.

Because facility-level reporting is impracticable, the proposed rule contains other provisions to improve our understanding of emissions from these source categories. For example, agricultural soil management is a significant source of N_2O. Activity data, including synthetic nitrogen-based fertilizer applications, influence N_2O emissions from this agricultural source category. To gain additional information on synthetic nitrogen-based fertilizers, EPA is proposing that the industrial facilities reporting under this rule include information on the production and nitrogen content of fertilizers as part of their annual reports to EPA. It is estimated that all of the synthetic nitrogen-based fertilizer produced in the U.S. is manufactured by industrial facilities that are covered under this rule due to onsite combustion-related and industrial process emissions (e.g., ammonia manufacturing facilities). The reporting requirements are contained in proposed 40 CFR part 98, subpart A.

EPA is requesting comment on this approach. In particular, the Agency is looking for information on the usefulness of the fertilizer data for estimating N_2O emissions from agricultural soils, and also on including other possible reporters of synthetic nitrogen-based fertilizers, such as fertilizer wholesalers or distributors, or importers in order to develop a better understanding of the source of N_2O emissions from fertilizer use.

For additional background information on emissions from agricultural sources and other land use, please refer to the TSD for Biological Process Sources Excluded from this Rule (EPA–HQ–OAR–2008–0508–045).

C. Rationale for Selection of Thresholds

The proposed rule would establish reporting thresholds at the facility level.[48] [49] [50] Only those facilities that exceed a threshold as specified in proposed 40 CFR part 98, subpart A would be required to submit annual GHG reports.

The thresholds are expressed in several ways (e.g., actual emissions or capacity). The use of these different types of thresholds is discussed later in this section, but most correspond to an annual facility-wide emission level of 25,000 metric tons of CO_2e, and the thresholds result in covering approximately 85–90 percent of U.S. emissions. That level is largely consistent with many of the existing GHG reporting programs, including California, which also has a 25,000 metric ton of CO_2e threshold. Furthermore, many industry stakeholders that EPA met with expressed support for a 25,000 metric ton of CO_2e threshold because it sufficiently captures the majority of GHG emissions in the U.S., while excluding smaller facilities and sources.[51] The three exceptions to the 25,000 metric ton of CO_2e threshold are electricity production at selected units subject to existing Federal programs, fugitive emissions from coal mining, and emissions from mobile sources. These thresholds were selected to be consistent with existing thresholds for reporting similar data to EPA and the MSHA. The proposed thresholds maximized the rule coverage with over 85 percent of U.S. emissions reported by approximately 13,000 reporters, while keeping reporting burden to a minimum and excluding small emitters.

Consideration of alternative emissions thresholds. In selecting the proposed threshold level, we considered two lower emission threshold alternatives and one higher alternative. We collected available data on each industry and analyzed the implication of various thresholds in terms of number of facilities and level of emissions covered at both the industry level and the national level. We also performed a similar analysis for each proposed source category to determine if there were reasons to develop a different threshold in specific industry sectors. From these analyses, we concluded that a 25,000 metric ton threshold suited the needs of the reporting program by providing comprehensive coverage of

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[48] Facilities reporting under this rule will likely have more than one source category within their facility (e.g., a petroleum refinery would have to report on its refinery process, combustion, landfill and wastewater emissions).

[49] 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.

[50] A different threshold approach is proposed for vehicle and engine manufacturers (when reporting emissions from the vehicles and engines the produce). Here, EPA proposes to exempt small businesses from reporting requirements, instead of applying an emission-based threshold.

[51] To view a summary of EPA's outreach efforts please refer to EPA–HQ–OAR–2008–0508–055.

emissions with a reasonable number of reporters and that having a uniform threshold was an equitable approach. This conclusion took into account our finding that a threshold other than 25,000 metric tons of CO_2e might appear to achieve an appropriate balance between number of facilities and emissions covered for a limited number of source categories. Our conclusions about the alternative thresholds are summarized below and in the Thresholds TSD (EPA–HQ–OAR–2008–0508–046), and the considerations for individual source categories are explained in Section V of this preamble.

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. Both broaden national emissions coverage but do so by disproportionately increasing the number of affected facilities (e.g., increasing the number of reporters by an order of magnitude in the case of a 1,000 metric tons CO_2e/yr threshold and doubling the number of reporters in the case of a 10,000 metric tons CO_2e/yr threshold). The majority of stakeholders were opposed to these lower thresholds for that reason—the gains in emissions coverage are not adequately balanced against the increased number of affected facilities.

A 1,000 metric ton of CO_2e per year threshold would increase the number of affected facilities by an order of magnitude over the proposed threshold. The effect of a 1,000 metric ton threshold would be to change the focus of the program from large to small emitters. This threshold would impose reporting costs on tens of thousands of small businesses that in total would amount to less than 10 percent of national GHG emissions.

A 10,000 metric ton of CO_2e per year threshold approximately doubles the number of facilities affected compared to a 25,000 metric ton threshold. The effect of a 10,000 metric ton threshold would only improve national emissions coverage by approximately 1 percent. The extra data that would result from a 10,000 metric ton threshold would do little to further the objectives of the program. EPA believes the 25,000 metric ton threshold more effectively targets large industrial emitters, which are responsible for some 90 percent of U.S. emissions. Similarly, California's mandatory GHG reporting program also based their selection of a 25,000 metric ton threshold on similar results at the State level.[52]

We also considered 100,000 metric tons of CO_2e per year as an alternative threshold but concluded that it fails to satisfy two key objectives. First, it may exclude enough 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 several large industry sectors would be rather significantly fragmented, resulting in an incomplete picture of direct emissions from that sector. For example, at a 100,000 metric ton of CO_2e threshold in ammonia manufacturing, approximately 22 out of 24 facilities would have to report; in nitric acid production, approximately 40 out of 45 facilities would have to report; in lime manufacturing, 52 out of 89 facilities would have to report; and in pulp and paper, 410 out of 425 facilities would have to report. Several stakeholders we met with stressed this potential fragmentation as a concern and requested that EPA include all facilities in a particular sector to simplify compliance, even if there was some uncertainty about whether all facilities in an industry would technically meet a particular threshold. For more information about the impact of thresholds on different industries, please see the source-specific discussion in Section V of this preamble.

The data collected by this rulemaking is intended to support analyses of future policy options. Those options may depend on harmonization with State or even international reporting programs. Several States and regional GHG programs are using thresholds that are comparable in scope to a 25,000 metric ton of CO_2e per year threshold.[53] As noted earlier, California specifically chose a threshold of 25,000 metric ton of CO_2e after analyzing CO_2 data from the air quality management districts because they concluded that level provided the correct balance of emissions coverage and number of reporters. Implementing a national reporting program using a 100,000, 10,000 or 1,000 metric ton of CO_2e per year limit would result in a fragmentary dataset insufficient in detail or coverage, or a more burdensome reporting requirement, and these options would be inconsistent with what many other GHG programs are requiring today.

In addition to the typical emissions thresholds associated with GHG reporting and reduction programs (e.g., 25,000 metric tons CO_2e), under the CAA, there are (1) the Title V program that requires all major stationary sources, including all sources that emit or have the potential to emit over 100 tons per year of an air pollutant, to hold an operating permit[54] and (2) the PSD/NSR program that requires new major sources and sources that are undergoing major modifications to obtain a permit. A major source for PSD is defined as any source that emits or has the potential to emit either 100 or 250 tons per year of a regulated pollutant, dependent on the source category.[55] In nonattainment areas, the major source threshold for NSR is at most 100 tons per year, and is less in some areas depending on the pollutant and the nonattainment classification of the area.

EPA performed some preliminary analyses to generally estimate the existing stock of major sources in order to then estimate the approximate number of new facilities that could be required to obtain NSR/PSD permits.[56] For example, if the 100 and 250 tons per year thresholds were applied in the context of GHGs, the Agency estimates the number of PSD permits required to be issued each year would increase by more than a factor of 10 (*i.e.*, more than 2,000 to 3,000 permits per year). The additional permits would generally be issued to smaller industrial sources, as well as large office and residential buildings, hotels, large retail establishments, and similar facilities.

For more information about the affect of thresholds considered for this rule on the number of reporters, emissions coverage and costs, please see Table VIII–2 in Section VIII of this preamble and Table IV–47 of the RIA found at EPA–HQ–OAR–2008–0508–002.

Determining applicability to the rule. The thresholds listed in proposed 40 CFR part 98, subpart A fall into three groups: Capacity, emissions, or ''all in.'' The thresholds developed are generally equivalent to a threshold of 25,000 metric tons of CO_2e per year of actual emissions.

EPA carefully examined thresholds and source categories that might be able

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[52] For more information on CA analysis please see *http://www.arb.ca.gov/regact/2007/ghg2007/isor.pdf.*

[53] For more information about what different States are requiring, see section II of this preamble, the ''Summary of Existing State GHG Rules'' memorandum and ''Review of Existing Programs'' memorandum found at EPA–HQ–OAR–2008–0508–056 and 054.

[54] Other sources required to obtain Title V operating permits include all sources that are required to have PSD permits, ''affected sources'' under the ARP, and sources subject to NSPS or NESHAP (although non-major sources under those programs can be exempted by rule).

[55] The 100 tons per year level is the level at which existing sources in 28 industry categories listed in the CAA are classified as major sources for the PSD program. The 250 tons per year level is the level at which existing sources in all other categories are classified as major sources for PSD purposes.

[56] For more information about the major source analysis please see docket number EPA–HQ–OAR–2008–0318.

to report utilizing a capacity metric, for example, tons of product produced per year. A capacity-based threshold could be the least burdensome alternative for reporting because a facility would not have to estimate emissions to determine if the rule applies. However, EPA faced two key challenges in trying to develop capacity thresholds. First, in most cases we did not have sufficient data to determine an appropriate capacity threshold. Secondly, for some source categories defining the appropriate capacity metric was not feasible. For example, for some source categories, GHG emissions are not related to production capacity, but are more affected by design and operating factors.

The scope of the proposed emission threshold is emissions from all applicable source categories located within the physical boundary of a facility. To determine emissions to compare to the threshold, a facility that directly emits GHGs would estimate total emissions from all source categories for which emission estimation methods are provided in proposed 40 CFR part 98, subparts C through JJ. The use of total emissions is necessary because some facilities are comprised of multiple process units or collocated source categories that individually may not be large emitters, but that emit significant levels of GHGs collectively. The calculation of total emissions for the purposes of determining whether a facility exceeds the threshold should not include biogenic CO_2 emissions (e.g., those resulting from combustion of biofuels). Therefore, these emissions, while accounted for and reported separately, are not considered in a facility's emissions totals.

In order to ensure that the reporting of GHG emissions from all source categories within a facility's boundaries is not unduly burdensome, EPA has proposed flexibility in two ways. First, a facility would only have to report on the source categories for which there are methods provided in this rule. EPA has proposed methods only for source categories that typically contribute a relatively significant amount to a facility's total GHG emissions (e.g., EPA has not provided a method for a facility to account for the CH_4 emissions from coal piles). Second, for small facilities, EPA has proposed simplified emission estimation methods where feasible (e.g., stationary combustion equipment under a certain rating can use a simplified mass balance approach as opposed to more rigorous direct monitoring).

The proposed emissions threshold is based on actual emissions, with a few exceptions described below. An actual emission metric accounts for actual operating practices at each facility. A threshold based on potential emissions would bring in far more facilities including many small emitters. For example, under a potential emissions threshold, a facility that operates one shift a day would have to estimate emissions assuming three shifts per day, and would have to assume continuous use of feedstocks or fuels that result in the highest rate of GHG emissions absent enforceable limitations. Such an approach would be inconsistent with the twin goals of collecting accurate data on actual GHG emissions to the atmosphere and excluding small emitters from the rule. However, we note that emissions thresholds in some CAA rules are based on actual or potential emissions. Moreover, although actual emissions may change year to year due to fluctuations in the market and other factors, potential emissions are less subject to yearly fluctuations. We solicit comment on how considerations of actual and potential emissions should be incorporated into the proposed threshold.

There is one source category that has a proposed threshold based on GHG generation instead of emissions—municipal landfills. In this case, a GHG generation threshold is more appropriate because some landfills have installed CH_4 gas recovery systems. A gas recovery system collects a percentage of the generated CH_4, and destroys it, through flaring or use in energy recovery equipment. The use of a threshold based on GHG generation prior to recovery is proposed because it ensures reporting from landfills that have similar CH_4 emission generating activities (e.g., ensures that landfills of similar size and management practices are reporting).

As described in Section III of this preamble, in the case of 19 source categories all of the facilities that have that particular source category within their boundaries would be subject to the proposed rule. For these facilities, our analysis indicated that all facilities with that source category emit more than 25,000 metric tons of CO_2e per year or that only a few facilities emit marginally below this level. These source categories include large manufacturing operations such as petroleum refineries and cement production. This simplifies the applicability determination for facilities with these source categories.

When determining if a facility passes a relevant applicability threshold, direct emissions from the source categories would be assessed separately from the emissions from the supplier categories. For example, a company that produces and supplies coal would be subject to reporting as a supplier of coal (40 CFR part 98, subpart KK), because coal suppliers is an ''all in'' supplier category. But the company would separately evaluate whether or not emissions from their underground coal mines (40 CFR part 98, subpart FF) would also be reported.

In addition, the source categories listed in proposed 40 CFR 98.2(a)(1) and (2) and the supply operations listed in proposed 40 CFR 98.2(a)(4) represent EPA's best estimate of the large emitters of GHGs or large suppliers of fuel and industrial GHGs. In order to ensure that all large emitters are included in this reporting program, proposed 40 CFR 98.2(a)(3) also covers any facility that emits more than 25,000 metric tons of CO_2e per year from stationary fuel combustion units at source categories that are not listed in proposed 40 CFR 98.2(a)(2). To minimize the reporting burden, such facilities would be required to submit an annual report that covers stationary combustion emissions.

Furthermore, we recognize that a potentially large number of facilities would need to calculate their emissions in order to determine whether or not they had to report under proposed 40 CFR 98.2(a)(3). Therefore, to further minimize the burden on those facilities, we are proposing that any facility that has an aggregate maximum rated heat input capacity of the stationary fuel combustion units less than 30 mmBtu/hr may presume it has emissions below the threshold. According to our analysis, a facility with stationary combustion units that have a maximum rated heat input capacity of less that 30 mmBtu/hr, operating full time (e.g., 8,760 hours per year) with all types of fossil fuel would not exceed 25,000 metric tons CO_2e/yr (EPA–HQ–OAR–2008–0508–049). Under this approach, we estimate that approximately 30,000 facilities would have to assess whether or not they had to report according to proposed 40 CFR 98.2(a)(3).[57] Of the 30,000, approximately 13,000 facilities would likely meet the threshold and have to report. Therefore, an additional 17,000 facilities may have to assess their applicability but potentially not meet the threshold for reporting. We concluded that is a reasonable number of assessments in order to ensure all

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[57] This estimate is based on the Energy and Environmental Analysis, ''Characterization of the U.S. Industrial/Commercial Boiler Population'' (2005) (EPA–HQ–OAR–2008–0508–050). We assumed 3 boilers per manufacturing facility and 1 boiler per commercial facility. For additional information on the impact to these 30,000 facilities, please see the ICR and RIA (EPA–HQ–OAR–2008–0508–002).

large emitters in the U.S. are included in this reporting program. We are seeking comment on (1) whether the presumption for maximum rated heat input capacity of 30 mmBtu/hr is appropriate, (2) whether a different (lower or higher) mmBtu/hr capacity presumption should be set and (3) whether other capacity thresholds should be developed for different types of facilities. The comments should contain data and analysis to support the use of different thresholds.

We are proposing that once a facility is subject to this reporting rule, it would continue to submit annual reports even if it falls below the reporting thresholds in future years. (As discussed in section IV.K. of this preamble, EPA is proposing that this rule require the submission of data into the foreseeable future, although EPA is soliciting comment on other options.) The purpose of the thresholds is to exclude small sources from reporting. For sources that trigger the thresholds, it is important for the purpose of policy analysis to be able to track trends in emissions and understand factors that influence emission levels. The data would be most useful if the population of reporting sources is consistent, complete and not varying over time.

The one exception to the proposed requirement to continue submitting reports even if a facility falls below the reporting threshold is active underground coal mines. When coal is no longer produced at a mine, the mine often becomes abandoned. As discussed in Section V.FF of this preamble, we are proposing to exclude abandoned coal mines from the proposed rule, and therefore methods are not proposed for this source category.

We recognize that in some cases, this provision of ''once in, always in'' could potentially act as a disincentive for some facilities to reduce their emissions because under this proposal those facilities that did lower their emissions below the treshold would have to continue to report. To address this issue in California, CARB's mandatory reporting rule offers a facility that has emissions under the threshold for three consecutive years the opportunity to be exempt from the reporting program. We request comment on whether EPA should develop a similar process for this reporting program. Comments should include specifics on how the exemption process could work, e.g., the number of years a facility is under the threshold before they could be exempt, the quantity of emissions reductions required before a facility could be exempt, whether a facility should formally apply to EPA for an exemption or if it is automatic, etc.

EPA requests comment on the need for developing simplified emissions calculation tools for certain source categories to assist potential reporters in determining applicability. These simplified calculation tools would provide conservatively high emission estimates as an aid in identifying facilities that could be subject to the rule. Actual facility applicability would be determined using the methods presented for each source category in the rule.

For additional information about the threshold analysis EPA conducted see the Thresholds TSD (EPA–HQ–OAR–2008–0508–046) and the individual source category discussions in Section V of this preamble. In addition, Section V.QQ of this preamble describes the threshold for vehicle and engine manufacturers, which is a different approach from what is described in this section.

D. Rationale for Selection of Level of Reporting

EPA is proposing facility-level reporting for most source categories under this program. Specifically, the owner or operator of a facility would be required to report its GHG emissions from all source categories for which there are methods developed and listed in this proposal. For example, a petroleum refinery would have to report its emissions resulting from stationary combustion, production processes, and any fugitive or biological emissions. Facility-level reporting by owners or operators is consistent with other CAA or State-level regulatory programs that typically require facility or unit level data and compliance (e.g., ARP, NSPS, RGGI, and the California and New Mexico mandatory GHG reporting rules). This approach allows flexibility for firms to determine whether the owner or operator of the facility would report and avoid the challenges of establishing complex reporting rules based on equity or operational control.

In addition to reporting emissions at the total facility level, the emissions would also be broken out by source category (e.g., a petroleum refinery would separately identify its emissions for refinery production processes, wastewater, onsite landfills, and any other source categories listed in proposed 40 CFR part 98, subpart A that are located onsite). This would enable EPA to understand what types of emission sources are being reported, determine that the facility is reporting for all required source categories, and use the source-category specific estimates for future policy development. Within each source category, further breakout of emissions by process or unit may be specified. Information on process or unit-level reporting and associated rationale is contained in the source category sections within Section V of this preamble.

Although many voluntary programs such as Climate Leaders or TCR have corporate-level reporting systems, EPA concluded that corporate-level reporting is overly complex under a mandatory system involving many reporters and thus is not appropriate for this rule, except where discussed below. Complex ownership structures and the frequent changes in ownership structure make it difficult to establish accountability over time and ensure consistent and uniform data collection at the facility-level. Because the best technical knowledge of emitting processes and emission levels exists at the facility level, this is where responsibility for reporting should be placed. Furthermore, the ability to differentiate and track the level and type of emissions by facility, unit or process, is essential for development of certain types of future policy (e.g., NSPS).

The only exception to facility level reporting is for some supplier source categories (e.g., importers of fuels and industrial GHGs or manufacturers of motor vehicles and engines). Importers are not individual facilities in the traditional sense of the word. The type of information reported by motor vehicle and engine manufacturers is an extension of long-standing existing reporting requirements (e.g., reporting of criteria emissions rates from vehicle and engine manufacturers) and as such does not necessitate a change in reporting level. The reporting level for these source categories is specified in Section V of this preamble.

E. Rationale for Selecting the Reporting Year

EPA is proposing that the monitoring and reporting requirements would start on January 1, 2010.[58] The first report to EPA would be submitted by March 31, 2011, and would cover calendar year 2010. The year 2011 is therefore referred to as the first reporting year, and includes 2010 data (there is a discussion later in this section that takes comment on alternative approaches to the reporting year). EPA is requesting comment on whether or not we should select an alternative reporting date that

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[58] The exception is for vehicle and engine manufacturers when reporting emissions from the vehicles and engines they produce. For these sources, reporting requirements would apply beginning with the 2011 model year.

corresponds with the requirements of an existing reporting system.

For existing facilities that meet the applicability criteria in proposed 40 CFR part 98, subpart A, monitoring would begin on January 1, 2010. For new facilities that begin operation after January 1, 2010, monitoring would begin with the first month that the facility is operating and end on December 31 of that same calendar year in which they start operating. Each subsequent monitoring year would begin on January 1 and end on December 31 of each calendar year. EPA is proposing that new facilities monitor and report emissions for the first partial year after they begin operating so that EPA has as complete an inventory as possible of GHG emissions for each calendar year.

Due to the comprehensive reporting and monitoring requirements in this proposal, the Agency has concluded that it is not appropriate to require reporting of historical emissions data for years before 2010. Compiling, submitting, and verifying historical data according to the methodologies specified in this rule would create additional burdens on both the affected facilities and the Agency, and much of the needed data might not be available. Because Federal policy for GHG emissions is still being developed, the Agency's focus is on collecting data of known quality that is generated on a consistent basis. Collecting historic emissions data would introduce data of unknown quality that would not be comparable to the data reported under the program for years 2011 and beyond.

The first year of monitoring for existing facilities would begin on January 1, 2010. This schedule would give existing facilities lead time after the date the rule is promulgated to prepare for monitoring and reporting. Preparation would include studying the final rule, determining whether it applies to the facility, identifying the requirements with which the facility must comply, and preparing to monitor and collect the required data needed to calculate and report GHG emissions.

A beginning date of January 1, 2010 would allow sufficient time to begin monitoring and collecting data because many of the parameters that would need to be monitored under the proposed rule are already monitored by facilities for process management and accounting reasons (e.g., feedstock input rates, production output, fuel purchases). In addition, the monitoring methods specified by the rule are already well-known and documented; and monitoring devices required by the rule are routinely available, in ready supply (e.g., flow meters, automatic data recorders), and in some cases already installed. These same monitoring devices are already required by other air quality programs with which many of these same facilities are already complying.

It is reasonable for new sources that start operation after January 1, 2010, to begin monitoring the first month of operation because new sources would be aware of the rule requirements when they design the facility and its processes and obtain permits. They can plan the data collection and reporting processes and install needed monitoring equipment as they build the facility and begin operating the monitoring equipment when they begin operating the facility.

We recognize that although the Agency plans to issue the final rule in sufficient time to begin monitoring on January 1, 2010, we may be unable to meet that goal. Therefore, we are interested in receiving comments on alternative effective dates, including the following two options:

- Report 2010 data in 2011 using best available data: Under this scenario, the rule would be effective January 1, 2010, allowing affected facilities to use either the methods in proposed 40 CFR part 98 or best available data. As in the current proposal, the report would be submitted on March 31, 2011, and then full data collection, using the methods in 40 CFR part 98 would begin in 2011, with that report sent to EPA on March 31, 2012. Under this approach, EPA solicits comment on the types of best available data and methods that should be allowed in 2010, by source category, (e.g., fuel consumption, emissions by process, default emissions factors, fuel receipts, etc.) as well as additional basic data that should be reported (e.g., facility name, location). This approach is similar to the CARB mandatory reporting rule, which allowed affected facilities to report 2009 emissions in 2010 using best available data, and then requires 2010 data collection in 2011 using the methods in the rule. The advantages of this approach are that the dates of the proposal remain intact and EPA receives basic information, including emissions and fuel data from all affected facilities in 2011. Furthermore, this approach can ease facilities into the program by giving them potentially a full year to implement the required methods and install any necessary equipment. For example, this option encourages the use of the methods in 40 CFR part 98 but if that is not possible, it allows the use of best available data (e.g., if a facility does not have a required flow meter installed for 2010 they can substitute the data from their fuel receipts in the calculation). The disadvantage of this approach is that it delays full data collection using the methods in the rule by 1 year from what is proposed. Further, in some cases, this approach could lead to data that is of lesser quality than the data we would receive using the methods in 40 CFR part 98. In other cases, because sources are already following the methods in 40 CFR part 98 (e.g., stationary combustion units in the ARP), the quality of the data would remain unchanged under this option. Given the objective of this rule to collect comprehensive and accurate data to inform future policies and the interest in Congress in developing climate change legislation, any delay in receiving that data could adversely affect the ability to inform those policies. That said, the data we would receive in 2011 under this option would at least provide basic information about the types, locations, emissions and fuel consumption from facilities in the United States.
- Report 2011 data in 2012: Under this scenario, the rule would require that affected facilities begin collecting data January 1, 2011 and submit the first reports to EPA on March 31, 2012. The methods in the proposed rule would remain unchanged and the only difference is that this option would delay implementation of the rule by one year. The advantages of this approach are that affected facilities would have a substantial amount of time to prepare for this reporting rule, including implementing the method and installing equipment. In addition, we would have even more time to conduct outreach and guidance to affected facilities. The disadvantages of this approach are that it delays implementation of this rule by a year and does not offer a mechanism for EPA to receive crucial data, even basic data, necessary to inform future policy and regulatory development. Furthermore, in some cases affected facilities are already implementing the methods required by proposed 40 CFR part 98 (e.g., stationary combustion units in the ARP) or are familiar with the methods, and have all of the necessary equipment or processes in place to monitor emissions consistent with the methods in 40 CFR part 98. Therefore, delaying implementation by a year not only deprives EPA of valuable data to support future policy development, but at the same time, does not provide any real advantage to these facilities.

Proposed 40 CFR part 98, subpart A, specifies numerical reporting thresholds for different direct emitters or supply operations. A facility or supply operation that exceeds any of these reporting thresholds in 2010 would submit a full emissions report in reporting year 2011, which contains calendar year 2010 data. The facilities and supply operations that contain many of the source categories that are listed in 40 CFR part 98, subpart A are larger facilities that have been participating in a variety of mandatory and voluntary GHG emissions programs. Therefore, those facilities and supply operations should be familiar with the methods and able to comply with the requirements and submit a full report without significant burden.

As discussed earlier, if a facility does not have any of the source categories listed in proposed 40 CFR 98.2 (a)(1) or (2), but has stationary combustion onsite that exceeds the GHG reporting threshold in 2010, they would still be required to estimate GHG emissions in 2010 and report in 2011. However, because those facilities would not contain any of the source categories specifically identified in proposed 40 CFR 98.2 (a)(1) or (2) and tend to be smaller facilities in diverse industrial sectors, they may require some extra time to implement the requirements of this rule. As such, they would be allowed to use an abbreviated facility report using simplified emission estimation methods for the first year (i.e., for calendar year 2010) and would not be required to complete a full report until the second reporting year (i.e., 2012).

The abbreviated report would allow the facility to use default fuel-specific CO_2 emission factors. They would not be required to determine actual fuel carbon content or to use a CEMS to determine CO_2 emissions, as they may otherwise be required to do with a full report. This provision for abbreviated reporting requirements has been proposed because there are potentially many facilities that are not in the listed industries, but are required to report solely due to stationary combustion sources at their facility. These include numerous and diverse sources in a wide variety of industries, some of which may not be as familiar with GHG monitoring and reporting. Such sources may often need more time to determine if they are above the threshold and subject to the rule and, if they are, to implement the full monitoring and reporting systems required. Therefore, the abbreviated report with simpler estimating methodologies is being proposed for these sources for the first year of monitoring and reporting.

EPA proposes that the annual GHG emissions reports would be submitted no later than March 31 for the previous calendar year's reporting period. Three months is a reasonable time to compile and review the information needed for the annual GHG emissions report and to prepare and submit the report. The data needed to estimate emissions and compile the report would be collected by the facility on an ongoing basis throughout the year, so facilities could begin data summary during the year as the data are collected. For example, they could compile needed GHG calculation input data (e.g., fuel use or raw material consumption data) or emission data on a periodic basis (e.g., monthly or quarterly) throughout the year and then total it at the end of the year. Therefore, only the most recently collected information would need to be compiled and a final set of calculations would need to be performed before the final report is assembled. Given the nature of the methodologies contained in the rule, three months is sufficient time to calculate emissions, quality-assure, certify, and submit the data.

F. Rationale for Selecting the Frequency of Reporting

EPA is proposing that all affected facilities would have to submit annual GHG emission 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. The annual CO_2 mass emissions from the ARP reports would simply be converted to metric tons and included in the GHG report. This approach should not impose a significant burden on ARP sources.

We have determined that annual reporting is sufficient for policy development. It is consistent with other existing mandatory and voluntary GHG reporting programs at the State and Federal levels (e.g., TCR, several individual State mandatory GHG reporting rules, EPA voluntary partnership programs, the DOE voluntary GHG registry). However, as future policies develop it may be necessary to reconsider the reporting frequency and require more or less frequent reporting (e.g., quarterly or every few years). For example, under future programs or policy initiatives, particularly if regulatory in nature (e.g., a cap-and-trade program similar to the ARP) it may be more appropriate require quarterly reporting.

G. Rationale for the Emissions Information To Report

1. General Content of Reports

Generally, we propose that facilities report emissions for all source categories at the facility for which methods have been defined in any subpart of proposed 40 CFR part 98. Facilities would report (1) total annual GHG emissions in metric tons CO_2e and (2) separately present annual mass emissions of each individual GHG for each source category at the facility.[59] 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 would be valuable for future policy development and help EPA quantify the relative contribution of each gas to a source category's emissions, while maintaining the transparency of reporting total mass of individual gases released by facility, unit, or process.

Emissions would be reported at the level (facility, process, unit) at which the emission calculation methods are specified in each applicable subpart. For example, if a pulp and paper mill has three boilers and a wastewater treatment operation, the facility would report emissions for each boiler (according to the methodologies presented in proposed 40 CFR part 98, subpart C), the wastewater treatment operation (according to proposed 40 CFR part 98, subpart II), and from chemical recovery units, lime kilns, and makeup chemicals (according to proposed 40 CFR part 98, subpart AA). In addition, the report would include summary information on certain process operating data that influence the level of emissions and that are necessary to calculate GHG emissions and verify those calculations using the methodologies in the rule. Examples of these data include fuel type and amount, raw material inputs, or production output. The specific process information to report varies for each source category and is specified in each subpart.

Furthermore, in addition to any specific requirements for reporting emissions from electricity generation in Sections V.C and V.D of this preamble, EPA is proposing that all facilities and supply operations affected by this rule would also report the quantity of electricity generated onsite. The generation of onsite electricity can

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[59] Consistent with the IPCC, the CARB reporting rule and the EU Emission Trading System, the proposed rule requires units to separately report the biogenic portion of their total annual CO_2 emissions.

represent a relatively significant fraction of onsite fuel use. We seek comment on whether this information would be useful to support future climate policy development, given the other data related to GHG emissions from electricity generation already collected under other sections of this proposed rule. At this point, we do not propose separate reporting of the onsite electricity generation by generation source (e.g., combined heat and power or renewable or fossil-based) due to the burden on reporters, but we recognize the potential value of being able to discern the quantity of electricity being generated from renewable and non-renewable sources. We are seeking comment on the value of collecting this data; and if it is collected, whether there is a need to separately report the kilowatt-hours by type of generation source.

We are also taking comment on, but not proposing at this time, requiring facilities and supply operations affected by the proposed rule to also report the quantity of electricity purchased. For many industrial facilities, purchased electricity represents a large part of onsite energy consumption, and their overall GHG emissions footprint when taking into account the indirect emissions from fossil fuel combusted for the electricity generated. Together, the reporting of electricity purchase data and onsite generation could provide a better understanding of how electricity is used in the economy and the major industry sectors.

Many existing reporting programs require reporting of indirect emissions (e.g., Climate Leaders, CARB, TCR, DOE 1605(b) program). In general, the protocols for these programs follow the methods developed by WRI/WBCSD for the quantification and reporting of indirect emissions from the purchase of electricity. The WRI/WBCSD protocol outlines three scopes to help delineate direct and indirect emission sources, with the stated goal to improve transparency, and provide utility for different types of organizations and different types of climate policies and business goals. Scope 1 includes direct GHG emissions occurring from sources that are owned or controlled by the business. Scope 2 includes indirect GHG emissions resulting from the generation of purchased electricity, heat, and/or steam. Scope 3 is optional and includes other types of indirect emissions (e.g., from production of purchased materials, waste disposal or employee transportation).

We are taking comment on, but not proposing at this time, an approach that would require the reporting of electricity purchase data, and not indirect emissions, because these data are more readily available to all facilities. Through the review of existing reporting programs that require the reporting of indirect emissions data it was determined that there are multiple ways proposed to calculate indirect emissions from electricity purchases. This reflects the challenge associated with determining the specific fossil fuel mix used to generate the electricity consumed by a facility, and thus the indirect emissions that should be attributed to the facility. Although indirect emissions data would not be directly reported under this approach, it would enable indirect emissions for facilities to be calculated. This option also would be the least burdensome to reporting facilities since the data would be easily available.

The information that is proposed to be reported reflects the data that could support analyses of GHG emissions for future policy development and ensure the data are accurate and comparable across source categories. Besides total facility emissions, it benefits policymakers to understand: (1) The specific sources of the 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. This level of reporting should not be overly burdensome because many of these data already are routinely monitored and recorded by facilities for business reasons. The remainder of the reported data would need to be collected to determine GHG emissions.

The report would contain a signed certification from a representative designated by the owner or operator of a facility affected by this rule. This ''Designated Representative'' would act as a legal representative between the source and the Agency. The use of the Designated Representative would simplify the administration of the program while ensuring the accountability of an owner or operator for emission reports and other requirements of the mandatory GHG reporting rule. The Designated Representative would certify that data submitted are complete, true, and accurate. The Designated Representative could appoint an alternate to act on their behalf, but the Designated Representative would maintain legal responsibility for the submission of complete, true, and accurate emissions data and supplemental data.

Besides these general reporting requirements, the specific reporting requirements for each source category are described in the methodological discussions in Section V of this preamble.

2. De minimis Reporting for Minor Emission Points

A number of existing GHG reporting programs contain ''de minimis'' provisions. The goal of a de minimis provision is to avoid imposing excessive reporting costs on minor emission points that can be burdensome or infeasible to monitor. Existing GHG reporting programs recognize that it may not be possible or efficient to specify the reporting methods for every source that must be reported and, therefore, have some type of provision to reduce the burden for smaller emissions sources. Depending on the program, the reporter is allowed to either not report a subset of emissions (e.g., 2 to 5 percent of facility-level emissions) or use simplified calculation methods for de minimis sources.

We analyzed the de minimis provisions of existing reporting rules and concluded that there is no need to exclude a percentage of emissions from reporting under this proposal. EPA recognizes the potential burden of reporting emissions for smaller sources. The proposal addresses this concern in several ways. First, only those facilities over the established thresholds would be required to report. Smaller facilities would not be subject to the program. Second, for those facilities subject to the rule, only emissions from those source categories for which methods are provided would be reported. Methods are not proposed for what are typically smaller sources of emissions (e.g., coal piles on industrial sites). Third, because some facilities subject to the rule could still have some relatively small sources, the proposal includes simplified emissions estimation methods for smaller sources, where appropriate. For example, small stationary combustion units could use a default emission factor and heat rate to estimate emissions, and no fuel measurements would be required. Where simplified methods are proposed, they are described in the relevant discussions in Section V of this preamble.

Our analysis showed that the GHG reporting programs with de minimis exclusions are structured differently than our proposed rule. For example, most rules with de minimis exclusions require corporate level reporting of all emission sources. Under these programs, some corporations must report emissions from numerous remote facilities and must report emissions from small onsite equipment (e.g., lawn mowers). For these programs, a de minimis exclusion avoids potentially unreasonable reporting burdens. The recent trend in these programs, however, is to require full reporting of all required GHG emissions, but allow simplified calculation procedures for small sources. In contrast to these other reporting programs, today's proposed rule would affect only larger facilities, would require reporting of significant emission points only, and would contain simplified reporting where practicable. Accordingly, a de minimis exclusion is not necessary. EPA requests comment on whether this approach to smaller sources of emissions is appropriate or if we should include some type of de minimis provision.

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–2008–0508–048).

3. Recalculation and Missing Data

Most voluntary and mandatory GHG reporting programs include provisions for operators to revise previously submitted data. For example, some voluntary programs require reporters to revise their base year emissions calculations if there is a significant change in the boundary of a reporter, a change in methodologies or input data, a calculation error, or a combination of the above that leads to a significant change in emissions. Recalculation procedures particularly appear to be central in voluntary GHG reporting programs that are also tracking emissions reductions.

Moreover, some programs (e.g., ARP) have detailed provisions for filling in data gaps that are missing in the required report. For example, in ARP, these procedures apply when CEMS are not functioning and as a result several hours of the required hourly data are missing. Note, however, that merely filling in data gaps that are missing or correcting calculation errors does not relieve an operator from liability for failure to properly calculate, monitor and test as required.

For this mandatory GHG reporting program, EPA concluded it was important to have missing data procedures in order to ensure there is a complete report of emissions from a particular facility. However, because this program requires annual reporting rather than quarterly reporting of hourly data as in ARP, the missing data provision often require the facility to redo the test or calculation of emissions. Section V of the preamble details the missing data procedures for facilities reporting to this program. EPA is seeking comment on whether to include a provision to require a minimum standard for reported data (e.g., only 10 percent of the data reported can be generated using missing data procedures).

In addition to establishing procedures for missing data, there may be benefit in requiring previously submitted data to be recalculated in order to ensure that the GHG emissions reported by a facility are as accurate as possible. The proposed California mandatory GHG reporting program, for example, allows reporters to revise submitted emissions data if errors are identified, subject to approval by the program.

EPA is considering whether or not to include provisions to require facilities to correct previously submitted data under certain circumstances. However, these benefits must also be weighed against the additional costs associated with requiring reporters to recalculate and resubmit previous data, and the magnitude of the emissions changes expected from such recalculations. Moreover, even if EPA were to allow recalculation of submitted data or accept data submitted using missing data procedures, that would not relieve the reporter of their obligation to report data that are complete, accurate and in accordance with the requirements of this rule. Although submitting recalculated data or data using missing data procedures would correct the data that are wrong, that resubmission or missing data procedures does not necessarily reverse the potential rule violation and would not relieve the reporter of any penalties associated with that violation. EPA is seeking comment on whether the mandatory GHG reporting program should include provisions to require reporters to submit recalculated data and under what circumstances such recalculations should be required.

H. Rationale for Monitoring Requirements

In selecting the monitoring requirements for the proposed rule, EPA's goal is to collect data of sufficient accuracy and quality to be used to inform future climate policy development and support a range of possible policies and regulations. Future policies and regulations could range from research and development initiatives to regulatory programs (*e.g.* , cap-and-trade programs). Accurate and timely information is critical to making policy decisions and developing programs. However, EPA recognizes that methods that provide the most accurate data may also entail higher data collection costs. In selecting a general monitoring approach, EPA considered the relative accuracy and costs of different approaches, the monitoring methods already in use within the regulated industries, and consistency with the monitoring approaches required by various Federal and State mandatory and voluntary GHG reporting programs. Measurement methods can range from continuous direct emissions measurements to simple calculation methods that rely on default factors and assumptions. EPA considered four broad monitoring approaches for the mandatory GHG rule. These general approaches (options 1 through 4) and the rationale for the selected approach are described in this section. After a general approach was selected, EPA developed the specific proposed monitoring methods for each source category as described in Section V of this preamble.

Option 1. Direct Emission Measurement. Option 1 would require direct measurement of GHGs for all source categories where direct measurement is feasible. It would require installation of CEMS for CO_2 in the stacks from stationary combustion units and industrial processes. The approach would be similar to 40 CFR part 75 that require coal-fired EGUs to install, operate, and maintain CEMs for SO_2 and NO_X emissions and report hourly emissions data (although some lower-emitting units have the option to use fuel sampling and fuel flow rate metering to determine emissions). Like 40 CFR part 75, the direct measurement approach would have detailed requirements for the CEMS including stringent QA/QC requirements to monitor accuracy and precision.

Direct measurement is not technically feasible in all cases. For example, CEMS are not available for many of the GHGs that must be reported. Direct measurement is also infeasible for emissions that are not captured and emitted through a stack, such as CH_4 emissions from the surface of landfills or fugitive emissions from selected oil and natural gas operations. For sources where direct measurement is not technically feasible, this option would require the use of rigorous methods with a comparable level of accuracy to CEMS.

The direct measurement option has the highest degree of certainty of the data reported. It is also the most costly because all facilities where direct measurement is feasible would need to install, operate, and maintain emission monitors. Most facilities currently do not have CEMS to measure GHG emissions.

Option 2. Combination of Direct Emission Measurement and Facility-Specific Calculations. This option would require direct measurement of emissions from units at facilities that already are required to collect and report data using CEMS under other Federally enforceable programs (e.g., ARP, NSPS, NESHAP, SIPs). In some cases, this may require upgrading existing CEMS that currently monitor criteria pollutants to also monitor CO_2.

Facilities that do not have units that have CEMS installed would have the choice to either directly measure emissions or to use facility-specific GHG calculation methods. The measurement and calculation methods for each source category would be specified in each subpart. Depending on the source category, methods could include mass balance; measurement of the facility's use of fuels, raw materials, or additives combined with site-specific measured carbon content of these materials; or other procedures that rely on facility-specific data. For the supplier source categories (e.g., those that supply fuels or industrial GHGs), this option would require reporting of production, import, and export data. The supplier companies already closely track these data for financial and other reasons.

This option provides a relatively high degree of certainty and takes advantage of existing practices at facilities. This option is less costly than option 1 because most facilities are not required to install CEMS and can, in many cases, make use of data they are already collecting for other reasons.

Option 3. Simplified Calculation Methods. Under option 3, facilities would calculate emissions using simple inputs (e.g., total annual production) that are usually already measured for other reasons, and EPA-supplied default emission factors (many of which have been developed by industry consortiums, such as the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) (Cement Sustainability Initiative) Protocol). The default emission factors would represent national average factors. These methods and emission factors would not take into account facility-specific differences in processes or in the composition of raw materials, fuels, or products.

Under this option, the only facilities that would have to use more rigorous monitoring or site-specific calculations methods are facilities that are already required to report emissions under 40 CFR part 75. These facilities would continue to follow the CO_2 monitoring and reporting requirements of 40 CFR part 75.

Data collected under this option would have a lower degree of certainty than options 1 or 2. Furthermore, many facilities are already calculating GHG emissions to a higher degree of certainty for business reasons or for other mandatory or voluntary reporting programs, and option 3 would not make use of such available data. However, the cost to facilities is lower than under options 1 and 2.

Option 4. Reporter's Choice of Methods. Under this approach, reporters would have flexibility to select any measurement or calculation method and any emission factors for determining emissions. The rule would not prescribe any methods or present any specific options for determining emissions.

Data collected under this option would not be comparable across a given industry and across reporters subject to the program, thereby minimizing the usefulness of the data to support future policymaking. Although some facilities might choose to use direct measurement because CEMS are already installed at the facility, other facilities would select default calculations. This option would be the lowest cost to reporters.

Proposed Option. For the proposed rule, EPA selected option 2 (combination of direct measurement and facility-specific calculations) as the general monitoring approach. This option results in relatively high quality data for use in developing climate policies and supporting a wide range of potential future policy options. Because we do not yet know which specific policy options the data may ultimately be used to support, the reported GHG emission estimates should have a sufficient degree of certainty such that they could be used to help develop a potential variety of programs.

Option 2 strikes a 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., TCR, California programs, Climate Leaders). Because this option specifies methods for each source category, it should result in data that are comparable across facilities.

Option 1 (direct emission measurement) was not chosen because the cost to the reporters if all facilities had to install continuous emission monitoring systems would be unreasonably high in the absence of a defined policy that would require this type of monitoring. However, under the selected option, facilities that already use CEMS would still be required to use them for purposes of the GHG reporting rule.

Option 3 (simplified calculation methods) was not chosen because the data would be less accurate than option 2 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. Option 3 would also be inconsistent with several other GHG reporting programs such as TCR and California programs that contain more site-specific calculation methods for several of the source categories.

Option 4 (reporter's choice of methods) was not proposed because the accuracy and reliability of the reported data would be unknown and would vary from one reporter to the next. Because consistent methods would not be used under this option, the reported data would not be comparable across similar facilities. The lack of comparability would undermine the use of the data to support policy decisions.

EPA requests comments on the selected monitoring approach and on other potential options and their advantages and disadvantages.

I. Rationale for Selecting the Recordkeeping Requirements

EPA is proposing that each facility that would be required to submit an annual GHG report would also keep the following records, in addition to any records prescribed in each applicable subpart:

- 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;
- Documentation of the process used to collect the necessary data for the GHG emissions calculations;
- The GHG emissions calculations and methods used;
- All emission factors used for the GHG emissions calculations;
- Any facility operating data or process information used for the GHG emissions calculations;
- Names and documentation of key facility personnel involved in calculating and reporting the GHG emissions;
- The annual GHG emissions reports;
- A log book documenting any procedural changes to the GHG emissions accounting methods and any changes to the instrumentation critical to GHG emissions calculations;
- Missing data computations;
- A written QAPP;
- Any other data specified in any applicable subpart of proposed 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.

These data are needed to verify the accuracy of reported GHG emission calculations and, if needed, to reproduce GHG emission estimates using the methods prescribed in the proposed rule. Since the above information must be collected in order to calculate GHG emissions, the added burden of maintaining records of that information should be minimal.

Each facility would be required to retain all required records for at least 5 years. Records would be maintained for this period so that a history of compliance could be demonstrated and questions about past emission estimates could be resolved, if needed.

The records would be required to be kept in an electronic or hard-copy format (as appropriate) that is readily accessible within a reasonable time for onsite inspection and auditing. They would be recorded in a form that can be easily inspected and reviewed. The allowance of a variety of electronic and hard copy formats for records allows flexibility for facilities to use a system that meets their needs and is consistent with other facility records maintenance practices, thereby minimizing the recordkeeping burden.

J. Rationale for Verification Requirements

1. General Approach to Verification Proposed in This Rule

GHG emissions reported under this rule would be verified to ensure accuracy and completeness so that EPA and the public could be confident in using the data for developing climate policies and potential future regulations. To ensure the completeness and quality of data reported to the program, the Agency proposes self-certification with EPA verification. Under this approach, all reporters subject to this rule would certify that the information they submit to EPA is truthful, accurate and complete. EPA would then review the emissions data and supporting data submitted by reporters to verify that the GHG emission reports are complete, accurate, and meet the reporting requirements of this rule.

Given the scope of this rulemaking, this approach is consistent with many EPA regulatory programs. That said, this proposal does not preclude that in the future, as climate policies evolve, EPA may consider third party verification for other programs (e.g., offsets). Furthermore, many programs in the States and Regions may be broader in scope and the use of third party verifiers may be appropriate to meet the needs of those programs.

In addition, under the authorities of CAA sections 114 and 208, EPA has the authority to independently conduct site visits to observe monitoring procedures, review records, and verify compliance with this rule (see Section VII of this preamble for further information on compliance and enforcement). For vehicle and engine manufacturers, EPA is not proposing additional verification requirements beyond the current emissions testing and certification procedures. These procedures include well-established methods for assuring the completeness and quality of reported emission test data and EPA is proposing to include the new GHG reporting requirements as part of these methods.

2. Options Considered

In selecting this proposed approach to verification, the Agency reviewed verification requirements and procedures under a number of existing EPA regulatory programs, as well as existing domestic and international GHG reporting programs. Additional information on this review and the verification approaches can be found in a technical memorandum (''Review of Verification Systems in Environmental Reporting Programs,'' EPA–HQ–OAR–2008–0508–047). Based on this review, EPA considered three alternative approaches to verification: (1) Self-certification without independent verification, (2) self-certification with third-party verification, and (3) self-certification with EPA verification.

Option 1. Self-certification without independent verification. Under this option, the Designated Representative of the reporting facility would be required to sign and submit a certification statement as part of each annual emissions report. The certification would affirm that the report has been prepared in accordance with the requirements of the GHG reporting rule, and that the emissions data and other information reported is true and accurate to the best knowledge and belief of the certifying official. The reasons for requiring self-certification are contained in Section IV.G of this preamble. Under option 1, EPA would not independently verify the accuracy and consistency of the reported data. Furthermore, because this approach does not include independent verification by EPA or a third party, the facility would not have to submit the detailed data needed to verify emissions estimates. Such information would be retained at the facility. For example, facilities would not be required to submit detailed monitoring data, activity data (e.g., fuel use, raw material consumption, production rates), carbon content measurements, or emission factor data used to calculate emissions.

Option 1 is a low burden option for reporters submitting data for this rule. Reporters under this option would not have to pay for third-party verifiers and would not necessarily have to submit the additional data required under the other options. In addition, EPA would not incur the expense of conducting verification of the reported data or certifying independent verifiers to conduct verification activities. The major disadvantages of this approach are the greater potential for inconsistent and inaccurate data in the absence of independent verification and the lower level of confidence that the public, stakeholders and EPA may have in the data.

Option 2. Self-certification with third-party verification. Under this approach, reporters would submit the same self-certification statements as under option 1. In addition, reporters would be required to hire independent third-party verifiers. The third-party verifiers would review the emissions report and the underlying monitoring system records, activity data collection, calculation procedures, and documentation, and submit a verification statement that the reported emissions are accurate and free of material misstatement. Under this approach, records supporting the GHG emissions calculations would be retained at the facility for compliance purposes and provided to the verifiers, but not submitted to EPA. In addition, as discussed below, EPA would have to establish a system to certify the independent verifiers.

Self-certification with third-party verification provides greater assurance of accuracy and impartiality than self-certification without verification. While this option is consistent with some existing domestic and international GHG reporting programs such as TCR, the California mandatory reporting rule, CCAR, and the EU Emission Trading System, the majority of industry stakeholders that met with EPA are opposed to this approach for this rulemaking, primarily due to the additional cost. Compared to option 1, the third-party verification approach places two additional costs on reporters: (1) Reporters would need to hire and pay verifiers, at a cost of thousands of dollars per reporting facility, and (2) reporters would incur costs to assemble and provide to verifiers detailed supporting data for the emission estimates.

To ensure consistency and quality of the third-party verifications, EPA would need to develop verification protocols, establish a system to qualify and accredit the third-party verifiers, and conduct ongoing oversight and auditing of verifications to be sure that third-party verifications continue to be conducted in a consistent and high quality manner.

As mentioned above, as climate policy evolves, it may be appropriate for EPA to consider the use of third party verification in other circumstances (e.g., offsets).

Option 3. Self-certification with EPA verification. Under this option, reporters would submit the same self-certification as under option 1. Reporters also would assemble data to support their emissions estimates, similar to option 2 but submit it to EPA in their annual emission reports, rather than to a third party verifier. EPA would review the emissions estimates and the supporting data contained in the reports, and perform other activities (e.g., comparison of data across similar facilities, site visits) to verify that the reported emissions data are accurate and complete.

EPA verification provides greater assurance of accuracy and impartiality than self-reporting without verification. Compared to a third-party verification system, there would be a consistent approach to verification from one centralized verifier rather than a variety of separate verifiers although this option would require EPA to ensure consistency if it chose to use its own contractors to support its verification activities. In addition, a centralized verification system would provide greater ability to the government to identify trends and outliers in data and thus assist with targeted enforcement planning. Finally, an EPA verification approach is consistent with other EPA emissions reporting programs including EPA's ARP.[60] The cost to the reporter is intermediate between options 1 and 2. Although this approach would not subject reporters to the cost of paying for third-party verifiers, reporters would have to assemble and submit detailed supporting data to ensure proper verification by EPA. An EPA verification program would result in greater costs to the Agency than options 1 and 2, but due to economies of scale may result in lower overall costs.

3. Selection of Self-Certification With EPA Verification as the Proposed Approach

EPA is proposing self-certification with EPA verification (option 3) because it ensures that data reported under this rule are consistent, accurate, and complete. In addition, we are seeking comment on requiring third-party verification for suppliers of petroleum products, many of whom currently report to EPA under the Office of Transportation and Air Quality's fuels programs. Third-party verification could be reasonable in these instances because this rule, to some extent, would build on existing transportation fuels programs that already require audits of records maintained by these suppliers by independent certified public accountants or certified internal auditors. For more information about the approach to fuel suppliers please refer to Section V of this preamble.

EPA is successfully using self certification with EPA verification in a number of other emissions reporting programs. EPA verification option provides greater assurance of the accuracy, completeness, and consistency of the reported data than option 1 (no independent verification) and consistent with feedback from industry stakeholders, does not require reporters to hire third-party verifiers (option 2). In addition, EPA verification option does not require the establishment of an accreditation and approval program for third-party verifiers although it would require EPA to ensure consistency if it chose to use its own contractors to support its verification activities.

EPA judged that option 1 (no independent verification) does not ensure sufficient quality data for the possible future uses of the data. The potential inconsistency, inaccuracy, and increased uncertainty of the data collected under option 1 would make the data less useful for informing decisions on climate policy and supporting the development of a wide range of potential future policies and regulations.

We selected EPA verification (option 3) instead of third-party verification (option 2) because EPA verification is consistent with other EPA programs, has lower costs to reporters than option 2, and would result in a consistent verification approach applied to all submitted data. Even with a verifier accreditation and approval process, the third-party verification approach could entail a risk of inconsistent verifications because verification responsibilities are spread amongst numerous verifiers. Given the potential diversity of verifiers, the quality and thoroughness of verifications may be inconsistent and EPA audit and enforcement oversight would become the predominant factor in ensuring uniformity. Under option 2, EPA would also need to develop and administer a process to ensure that verifiers hired by the 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. Finally, EPA verification would likely avoid any delays that may be introduced by third-party verification and better ensure the timely reporting and use of the reported data. Some reporting programs provide four to six months after the annual emissions report is submitted for third-party verification. That said, as mentioned above, depending on the scope or type of program (e.g., offsets), EPA may consider the use of third party verification in the future as policy options evolve.

The Agency recognizes that, in some instances, data submitted by reporters under this rule may have been independently verified as the result of other mandatory or voluntary GHG reporting programs or by other Federal, State or local regulations. Whether or not data have been independently verified outside of the requirements of this proposed GHG reporting rule, EPA has concluded for the purposes of this proposal it is important to apply the same verification requirements to all affected facilities in order to ensure equity across all reporters and consistent data collection for policy analysis and public information.

K. Rationale for Selection of Duration of the Program

EPA is proposing that the rule require the reporting of GHG emissions data on an ongoing, annual basis. Other approaches that EPA considered include a one-time collection of information and collection of a limited duration (e.g., a three-year data collection effort).

EPA does not believe that a one-time data collection effort is consistent with the legislative history of the FY 2008 Consolidated Appropriations Act, which instructed EPA to develop a rule to require the reporting of GHG emissions. Typically, a rule is not required to undertake a one-time information collection request. Moreover, the President's FY 2010

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[60] For a description of how verification is conducted in ARP please see, ''Fundamentals of Successful Monitoring, Reporting, and Verification under a Cap-and-Trade Program.'' John Schakenbach, Robert Vollaro, and Reynaldo Forte, U.S. EPA/OAP. Journal of the Air and Waste Management Association 56:1576–1583. November 2006. (EPA–HQ–OAR–2008–0508–051.)

Budget, as well as initial Congressional budgets for the remainder of FY 2009 indicate that policy makers anticipate that the information will be collected for multiple years.

For example, on February 6, 2009, Senators Feinstein, Boxer, Snowe and Klobuchar sent a letter to EPA's Administrator Lisa Jackson and OMB's Director Peter Orszag stating that this program allowed EPA to ''gather critical baseline data on greenhouse gas emissions, which is essential information that policymakers need to craft an effective climate change approach.'' In addition, in recent testimony from John Stephenson, Director of Natural Resources and Environment at the Government Accountability Office,[61] stated that when setting baselines for past regulatory policies, averaging data ''across several years also helped to ensure that the baseline reflected changes in emissions that can result in a given year due to economic and other conditions.'' The testimony further noted the because EPA's ARP was able to average several years worth of data when setting the baseline for SO_2 reductions, the program ''achieved greater assurances that it reduced emissions from historical levels'' as opposed to the EU who did not have enough data to set accurate baselines for the first phase of the EU Emissions Trading System. Furthermore, EPA's experience with certain CAA programs show that a one-time snapshot of information is not always representative of normal operations, and hence emissions, of a facility. See, e.g., Final New Source Review (NSR) Reform Rules, 68 FR 80186, 80199 (2002). Finally, as discussed earlier, a multi-year reporting program allows EPA to track trends in emissions and understand factors that influence emissions levels.

EPA also considered a multi-year program that would sunset at a date certain in the future (e.g., three years) absent subsequent regulatory action by EPA to extend it. EPA decided against this approach because it would unnecessarily limit the debate about potential policy options to address climate change. At this time, it would be premature to guess at what point in the future this information may be less relevant to decision-making. Rather, a more prudent approach is to maintain the program until such time in the future when it is determined that the information for one or more source categories is no longer relevant to decision-making, or is adequately provided in the context of regulatory program (e.g., CAA NSPS). Notably, EPA crafted the requirements in this rule with the potential monitoring, recordkeeping and reporting requirements for any future regulations addressing GHG emissions in mind. EPA solicits comment on all of these possible approaches, including whether EPA should commit to revisit the continued necessity of the reporting program at a future date.

V. Rationale for the Reporting, Recordkeeping and Verification Requirements for Specific Source Categories

Section V of this preamble discusses the source categories covered by the proposed rule. Each section presents a description of a source category and the proposed threshold, monitoring methods, missing data procedures, and reporting and recordkeeping requirements.

A. Overview of Reporting for Specific Source Categories

Once you have determined that your facility exceeds any reporting threshold specified in 40 CFR 98.2(a), you would have to calculate and report GHG emissions, or alternate information as required (e.g., production and imports for industrial GHG suppliers) for all source categories at your facility for which there are measurement methods provided. The threshold determination is separately assessed for suppliers (fossil fuel suppliers and industrial GHG suppliers) and downstream source categories.

Facilities, or corporations, where relevant, that trigger only the threshold for upstream fossil fuel or industrial GHG supply (proposed 40 CFR part 98, subparts KK through PP) need only follow the methods in those respective sections. Facilities (or corporations) that contain source categories that also have downstream sources of emissions (e.g., proposed 40 CFR part 98, subparts B through JJ), or facilities that are exclusively downstream sources of emissions may have to monitor and report GHG emissions using methods presented in multiple sections. For example, a food processing facility should review Section V.C (General Stationary Fuel Combustion), Section V.HH (Landfills) and Section V.II (Wastewater Treatment) in addition to Section V.M (Food Processing) of this preamble. Table 2 of this preamble (in the SUPPLEMENTARY INFORMATION section of this preamble) provides a cross walk to aid facilities 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 V 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 would be relevant to all reporters. The remainder of this overview summarizes the general approach to calculating and reporting these downstream sources of emissions.

Consistent with the requirements in the proposed 40 CFR part 98, subpart A, facilities would have to report GHG emissions from all source categories located at their facility—stationary combustion, process (e.g., iron and steel), fugitive (e.g., oil and gas) or biologic (e.g., landfills) sources of GHG emissions. The methods presented typically account for normal operating conditions, as well as SSM, where significant (e.g., HCFC–22 production and oil and gas systems). Although SSM is not specifically addressed for many source categories, emissions estimation methodologies relying on CEMS or mass balance approaches would capture these different operating conditions.

For many facilities, calculating facility-wide emissions would simply involve adding GHG emissions calculated under Section V.C of this preamble (General Stationary Fuel Combustion Sources) and emissions calculated under the source-specific subpart. For other facilities, particularly selected sources in Sections V.E through V.JJ of this preamble that rely on mass balance approaches or the use of CEMS, the proposed methods would (depending on the operating conditions and configuration of the plant) capture both combustion and process-related emissions and there is no need to separately quantify combustion-related emissions using the methods presented in Section V.C of this preamble.

Generally, the proposed method depends on the equipment you currently have installed at the facility.

Sources with CEMS. If you have CEMS that meet the requirements in proposed 40 CFR part 98, subpart C you would be required to quantify and report the CO_2 emissions that can be monitored using the existing CEMS. Non-CO_2 combustion-related emissions would be estimated consistent with proposed 40 CFR part 98, subpart C, and other non-CO_2 emissions would be estimated using the source-specific methods provided.

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[61] High Quality Greenhouse Gas Emissions Data are a Cornerstone of Programs to Address Climate Change, Statement of John Stephenson, Director, Natural Resources and Environment, Government Accountability Office, February 24, 2009.

(1) Where the CEMS capture both combustion- and process-related emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate emissions from the industrial source. In this case, use of the additional methods provided in the source-specific discussions would not be required.

(2) Where the CEMS do not capture both combustion and process-related emissions, you should refer to the source-specific sections that provide methods for calculating process emissions. You would also be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate any stationary fuel combustion emissions from the industrial source.

Sources without CEMS. If you do not have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to carry out facility-specific calculations to estimate process emissions. You would also be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate any stationary fuel combustion emissions from the industrial source.

B. Electricity Purchases

At this time, we are not proposing that facilities report information to us regarding their electricity purchases or indirect emissions from electricity consumption. However, we carefully considered proposing that all facilities that report to us also report their total purchases of electricity. This section describes our deliberations and outlines potential methods for monitoring and reporting electricity purchases. We generally seek comment on the value of collecting information on electricity purchases. Further, we are specifically interested in receiving feedback on the approach outlined below.

1. Definition of the Source Category

The electric utility sector is the largest emitter of GHG emissions in the U.S. The level of GHG emissions associated with electricity use is determined not just by the fuel and combustion technology onsite at the power plant, but also by customer demand for electricity. Accordingly, electricity use and the efficiency of this use indirectly affect the emissions of CO_2, CH_4 and N_2O from the combustion of fossil fuel at electric generating stations.

For many facilities, purchased electricity represents a large part of onsite energy consumption, and their overall GHG emissions footprint when taking into account the indirect emissions from fossil fuel combusted for the electricity generated. Therefore, the reporting of electricity purchase data from facilities could provide a better understanding of how electricity is used in the economy and the major sectors. We would propose not to provide for adjustments to take into account the purchases of renewable energy credits or other mechanisms.

If included, this source category would include electricity purchases, but not include electricity generated onsite (i.e., facility-operated power plants, emergency back-up generators, or any portable, temporary, or other process internal combustion engines). General requirements for all reporters subject to the proposed rule to report on total kilowatt hours of electricity generated onsite is discussed in Section IV.G of the preamble. Calculating emissions from onsite electricity generation is addressed in Sections V.C and V.D of this preamble.

For additional background information on indirect emissions from electricity purchases, please refer to the Electricity Purchases TSD (EPA–HQ–OAR–2008–0508–003).

2. Selection of Reporting Threshold

Three options for reporting thresholds could be considered for the reporting of indirect emissions from purchased electricity (i.e., GHG emissions from the production of purchased electricity). These options would be as follows:

Option 1: Do not require any reporting on electricity purchases or associated indirect emissions from electricity purchases as part of this rule.

Option 2: Require reporting on 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 emissions threshold (including indirect emissions from the purchased electricity). Reporting for this option could be proposed either in terms of electricity purchases or calculated indirect CO_2e emissions based on purchased electricity. This option would require an additional number of reporters, based on their annual electricity purchases, to report indirect emissions.

No additional facilities to those already reporting their emissions data under this rule would be affected by the first or second options. The number of additional facilities affected by the third proposed threshold is estimated to be approximately: 250 facilities at a 100,000 metric tons CO_2e threshold; 5,000 total facilities at a 25,000 metric tons CO_2e threshold; 15,000 total facilities at a 10,000 metric tons CO_2e threshold; and 185,000 total facilities at a 1,000 metric tons CO_2e threshold.

Under all threshold options, reporting of information related to electricity purchases would apply to entities reporting at the facility level. This provision would not apply to source categories that we propose report at the corporate level (e.g., importers and exporters of industrial GHGs, local distribution companies, etc.). These companies in many cases may own large facilities such as refineries which already have a reporting obligation for direct emissions and electricity purchases.

Given the above considerations, our preferred option would be option 2. Purchased electricity is considered to be a significant portion of the GHG emissions of most industrial facilities, therefore the collection of indirect emissions from purchased electricity could be seen as an important component of the GHG mandatory reporting rule. Although such a reporting requirement would not provide EPA with emissions information, it could provide the necessary underlying data to develop emissions estimates in the future if this were necessary.

The reporting of electricity purchase data directly instead of calculated indirect emissions would be preferred due to the difficulties in identifying the appropriate electrical grid or electrical plant emission factor for converting a facility's electricity purchases to GHG emissions. EPA does not have data to evaluate the uncertainty of applying national, regional or State emission factors to electricity consumption at a given facility, versus undertaking detailed studies to determine the actual emissions from electricity purchases.

Under Option 2, all facilities that are already required to report their GHG emissions under this rule would also have to quantify and report their annual electricity purchases. The total purchased electricity would include electricity purchased from all sources (i.e., fossil fuel power plants, green power generating facilities, etc.). It should be noted that under this approach, data from large sources of indirect emissions due to electricity usage (e.g., non-industrial commercial buildings) would be not be collected.

3. Selection of Proposed Monitoring Methods

Purchased electricity could be quantified through the use of purchase receipts or similar records provided by the electricity provider. The facility could choose to use data from facility maintained electric meters in addition to or in lieu of data from an electricity provider (e.g., electricity purchase receipts, etc.), provided that this data could be demonstrated to accurately reflect facility electricity purchases. However, purchase receipts or electricity provider data would be the preferred method of quantifying a facility's electricity purchases. Because facilities would be expected to retain these data as part of routine financial records, the only additional burden of collecting this information would be to retain the records in a readily available manner.

In identifying the options outlined above, we reviewed five reporting programs and guidelines: (1) EPA Climate Leaders Program, (2) the CARB Mandatory Greenhouse Gas Emissions Program, (3) TRI, (4) the DOE 1605(b) program, and (5) the GHG Protocol developed jointly by WRI and WBCSD. In general, these protocols follow the methods presented in WRI/WBCSD for the quantification and reporting of indirect emissions from the purchase of electricity.

See the Electricity Purchases TSD (EPA–HQ–OAR–2008–0508–003) for more information.

4. Selection of Procedures for Estimating Missing Data

If we were to collect information on electricity purchases, we would propose that a facility be required to make all attempts to collect electricity records from their electricity provider. In the event that there were missing electricity purchase records, the facility would estimate its electricity purchases for the missing data period based on historical data (i.e., previous electricity purchase records). Any historical data used to estimate missing data should represent similar circumstances to the period over which data are missing (e.g., seasonal). If a facility were using electric meter data and had a missing data period, the facility could use a substitute data value developed by averaging the quality-assured values metered values for kilowatt-hours of electricity use immediately before and immediately after the missing data period.

5. Selection of Data Reporting Requirements

If we were to collect information on electricity purchases, we would propose that a facility report total annual purchased electricity in kilowatt-hours for the entire facility.

6. Selection of Records That Must Be Retained

If we were to collect information on electricity purchases, we would propose that the owner or operator maintain monthly electricity purchase records for all operations and buildings. If electric meter data were used, then monthly logs of the electric meter readings would also be proposed to be maintained.

C. General Stationary Fuel Combustion Sources

1. Definition of the Source Category

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters. The combustion process may be used to: (a) Generate steam or produce useful heat or energy for industrial, commercial, or institutional use; (b) produce electricity; or (c) reduce the volume of waste by removing combustible matter. As discussed in Section III of this preamble and proposed 40 CFR part 98, subpart A, this section applies to facilities with stationary fuel combustion sources that (a) have emissions greater than or equal to 25,000 metric tons CO_2e/yr; or (b) are referred to this section by other source categories listed in proposed 40 CFR 98.2(a)(1) or (2).

Combustion of fossil fuels in the U.S. is the largest source of GHG emissions in the nation, producing three principal greenhouse gases: CO_2, CH_4 and N_2O. For the purposes of this rule, CO_2, CH_4, and N_2O would be reported by stationary fuel combustion sources. The emission rate of CO_2 is directly proportional to the carbon content of the fuel, and virtually all of the carbon is oxidized to CO_2. The emission rates of CH_4 and N_2O are much less predictable, as these gases are by-products of incomplete or inefficient combustion, and depend on many factors such as combustion technology and other considerations. The CO_2 emissions generated by fuel combustion far exceed the CH_4 and N_2O emissions (CH_4 and N_2O contribute less than 1 percent of combined U.S. GHG emissions from stationary combustion, on a CO_2e basis), however, under this proposed rule, CO_2, CH_4, and N_2O would all be reported by stationary fuel combustion sources. EPA is proposing to not require reporting of emissions from portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency. We request comment on whether or not a permit should be required for these emergency generators.

A wide and diverse segment of the U.S. economy engages in stationary combustion, principally the combustion of fossil fuels. According to the ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006'', the nationwide GHG emissions from stationary fossil fuel combustion are approximately 3.75 billion metric tons CO_2e per year. This estimate includes both large and small stationary sources and represents more than 50 percent of total GHG emissions in the U.S.

EPA's proposed rule presents methods for calculating GHG emissions from stationary combustion, both at unspecified facilities as well as facilities in source categories listed in proposed 40 CFR 98.2(a)(1) and (2), which are based on the fuel combusted and the size of the stationary equipment (e.g., the maximum heat input capacity in mmBtu/hr). EPA already collects CO_2 emissions data from electricity generating units in the ARP,[62] which combust the vast majority of coal consumed in the U.S. annually. So, while detailed requirements are provided for facilities that combust solid fuels, these methods are likely to affect only a small percentage of facilities reporting under proposed 40 CFR part 98 (as separate methods, in proposed 40 CFR 98.40, would be used by electricity generating units already reporting under the requirements of ARP). In presenting methodologies in the following sections, EPA further notes that the majority of reporters under proposed 40 CFR part 98, subpart C would use the methods prescribed for stationary combustion equipment combusting natural gas.

Table C–1 of this preamble illustrates the methods for calculating CO_2 emissions for different types of reporters based on the fuel being combusted at the facility and the size of the stationary combustion equipment. The

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[62] It should be noted, as discussed in section V.D, EPA already collects over 90% of total CO_2 emissions from U.S. coal combustion through the 40 CFR part 75 requirements of ARP.

calculations for CH_4 and N_2O that are presented in subsequent subsections are to be applied to all fuel types and are not contingent upon the stationary cobustion equipment size.

TABLE C–1. FOUR-TIERED APPROACH FOR CALCULATING CO_2 EMISSIONS FROM STATIONARY COMBUSTION SOURCES

Combustion unit size	Additional requirement(s)	Methodological tier required [a]
Solid Fossil Fuel (e.g., Coal)		
> 250 mmBtu/hour	—Unit has operated more than 1,000 hours a year [b]	4
	—Unit has existing, certified gas monitors or stack gas volumetric flow rate monitor (or both); and	
	—Facility has an established monitoring infrastructure and meets specific QA/QC requirements.	
	—Unit does not meet conditions above	3
≤ 250 mmBtu/hr	—Unit operates more than 1,000 hours a year [b]	4
	—Unit has existing, certified CO_2 or O_2 concentration monitor and stack gas volumetric flow rate monitor; and	
	—Facility has an established monitoring infrastructure and meets specific QA/QC requirements.	
	—Unit does not meet conditions above	2
	—Monthly measured HHV is available.	
	—Unit does not meet conditions above	1
	—Monthly measured HHV is not available.	
Gaseous Fossil Fuel (e.g., Natural Gas)		
> 250 mmBtu/hr	None	3
≤ 250 mmBtu/hr	—Monthly measured HHV is available	2
	—Monthly measured HHV is not available	1
Fossil Liquid Fuel (e.g., Diesel)		
> 250 mmBtu/hr	None	3
≤ 250 mmBtu/hr	—Monthly measured HHV is available	2
	—Monthly measured HHV is not available	1
Biomass or Biomass-Derived Fuels (e.g., wood)		
All Sizes	—EPA has provided a default CO_2 emission factor and a default heating value for the fuel.	1
All Sizes	—EPA has provided a default CO_2 emission factor for specific fuel to be used with that fuel's measured heating value.	2
All Sizes	—EPA has not provided a default CO_2 emission factor for specific fuel to be used with that fuel's measured heating value.	3
MSW		
> 250 tons MSW/day	—Unit has operated more than 1,000 hours a year [b]	4
	—Unit has existing, certified gas monitors or stack gas volumetric flow rate monitor (or both); and	
	—Facility has an established monitoring infrastructure and meets specific QA/QC requirements.	
	—Unit does not meet conditions above	2
≤ 250 tons MSW/day	—Unit operates more than 1,000 hours a year [b]	4
	—Unit has existing, certified CO_2 concentration monitor and stack gas volumetric flow rate monitor; and	
	—Facility has an established monitoring infrastructure and meets specific QA/QC requirements.	
	—Unit does not meet conditions above	2

[a] Minimum tier level to be used by reporters. Reporters required to use Tier 1, 2, or 3 have the option to use a higher tier methodology.
[b] Hours of operation in any year since 2005.
Note: Facilities with units reporting CO_2 data to ARP should refer to Section V.D of this preamble (Electricity Generation).

2. Selection of Reporting Threshold

In developing the threshold for facilities with stationary combustion equipment, EPA considered an emissions-based threshold of 1,000, 10,000, 25,000, and 100,000 metric tons CO_2e. Table C–2 of this preamble illustrates the emissions covered and the number of facilities that would be covered under these various thresholds. It should be noted that Table C–2 of this preamble only includes facilities with stationary combustion equipment that are not covered in other subparts of the proposed rule. For this reason, the total emissions presented in Table C–2 of this preamble appear as a lower total than presented previously (the general discussion in Section C.1 of this preamble), where emissions from all stationary combustion equipment are being discussed.

TABLE C–2. THRESHOLD ANALYSIS FOR UNSPECIFIED INDUSTRIAL STATIONARY FUEL COMBUSTION

Threshold level metric tons CO_2e/yr	Total national emissions (million metric tons CO_2e)	Total number of facilities	Emissions covered		Facilities covered	
			Million metric tons CO_2e/yr	Percent	Number	Percent
1,000	410	350,000	250	61	32,000	9.1
10,000	410	350,000	230	56	8,000	2.3
25,000	410	350,000	220	54	3,000	0.9
100,000	410	350,000	170	41	1,000	0.3

In calculating emissions for this analysis, and for the proposed threshold, only CO_2 from the combustion of fossil fuels, in combination with all CH_4 and N_2O emissions, are considered. CO_2 emissions from biomass are not considered as part of the determination of the threshold level. This treatment of biomass fuels is consistent with the IPCC Guidelines and the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, which account for the release of these CO_2 emissions in accounting for carbon stock changes from agriculture, forestry, and other land-use. CH_4 and N_2O emissions from combustion of biomass are counted as part of stationary combustion within the IPCC and national U.S. GHG inventory frameworks.

The purpose of the general stationary combustion source category is to capture significant emitters of stationary combustion GHG emissions that are not covered by the specific source categories described elsewhere in this preamble. Therefore, EPA is proposing a threshold for reporting emissions from stationary combustion at 25,000 metric tons CO_2e.[63] EPA selected the proposed 25,000 metric tons CO_2e threshold as it appears to strike the best balance between covering a high percentage of nationwide GHG emissions and keeping the number of affected facilities manageable. As illustrated in Table C–2 of this preamble, selecting a 25,000 metric tons CO_2e threshold achieves the greatest incremental gain in coverage with the lowest increase in the number of covered sources.

The 100,000 metric tons CO_2e threshold was not proposed because EPA believes it would exclude too many significant emitters of GHG emissions that are not required to report pursuant to the other provisions of this rule. EPA believes that most of the population of facilities over a 100,000 metric tons CO_2e threshold is known either through source category studies or existing EPA reporting programs.

The 10,000 metric tons CO_2e threshold showed a smaller incremental gain in emissions coverage from a higher threshold than the 25,000 metric tons CO_2e threshold, while greatly increasing the incremental number of reporters (as illustrated in Table C–2 of this preamble). The 1,000 metric tons CO_2e threshold greatly increases the total number of reporters for this rule and places an unnecessary administrative burden on EPA, while not greatly increasing nationwide emissions coverage of stationary combustion sources.

In addition, although there is considerable uncertainty as to the number of facilities under a 25,000 metric tons CO_2e threshold, there is evidence to indicate that moving the threshold from 25,000 to 10,000 metric tons CO_2e would have a disproportionate impact on the commercial sector. It should also be noted that this concern is even more applicable to the 1,000 metric tons CO_2e threshold.

EPA concluded that a 25,000 metric tons CO_2e threshold would better achieve a comprehensive economy wide coverage of emissions while focusing reporting efforts on large industrial emitters. In particular, it would address the considerable uncertainties in the 25,000 to 100,000 metric tons CO_2e emissions range, both as to the number of reporters and the magnitude of emissions. EPA believes that a 25,000 metric tons CO_2e threshold would help in gathering data from a reasonable number of reporters for which little information is currently known without imposing undue administrative burden.

EPA also considered including GHG emissions from the combustion of biomass fuels in the emission threshold calculations. Therefore, the proposed rule states that GHG emissions from biomass fuel combustion are to be excluded when evaluating a facility's status with respect to the 25,000 metric tons CO_2e reporting threshold. This is similar to the approach taken by the IPCC and various other GHG emission inventories.

Finally, EPA considered a heat input capacity-based threshold (such as all facilities with stationary combustion equipment rated over 100 mmBtu/hr maximum heat input capacity). A complete, reliable set of heat input capacity data was unavailable for all facilities that might be subject to this rule, thus this type of threshold could not be thoroughly evaluated.

For a full discussion of the threshold analysis and for background information on this threshold determination, please refer to the Thresholds TSD (EPA–HQ–OAR–2008–0508–046). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

EPA's proposed methods for calculating GHG emissions from stationary fuel combustion sources is consistent with existing domestic and international protocols, as well as monitoring programs currently implemented by EPA. Those protocols and programs generally utilize either a direct measurement approach based on concentrations of combustion exhaust gases through a stack, or a direct measurement approach based on the quantity of fuel combusted and the characteristics of the fuel (e.g., heat content, carbon content, etc.). As the magnitude of CO_2 emissions released by stationary combustion sources relative to CH_4 and N_2O is greater (even on a CO_2e basis), more guidance is provided on the application of specific monitoring and calculation methods for CO_2. EPA is proposing simpler calculation methods for CH_4 and N_2O.

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[63] As described previously, the threshold only includes CO_2 from the combustion of fossil fuels and CH_4 and N_2O emissions from all fuel combustion. CO_2 emissions from biomass are not considered as part of the determination of the threshold level.

For facilities which have EGUs subject to the ARP reporting requirements under 40 CFR part 75, refer to Section V.D of this preamble regarding those units. For other units located at that facility (i.e., units that are not reporting to the ARP), the facility would use the calculation methods presented below.

The discussions which follow in this subsection will focus on methods for: (a) The calculation of CO_2 emissions from fuel combustion; (b) the calculation for the separate reporting of biogenic CO_2 emissions; (c) reporting biogenic CO_2 emissions from MSW; (d) the calculation of CH_4 and N_2O emissions; and (e) the calculation of additional CO_2 emissions from the sorbent in combustion control technology systems.

a. CO_2 Emissions From Fuel Combustion

To monitor and calculate CO_2 emissions from stationary combustion sources, EPA is proposing a four-tiered approach, which would be applied either at the unit or facility level. The most stringent emissions calculation methods would apply to large stationary combustion units that are fired with solid fuels and that have existing CEMS equipment. This is due to the complexity of monitoring solid fuel consumption and the heterogeneous nature of solid fuels. Furthermore, because of the significant mass of CO_2 emissions that are released by these large units, combining stringent methods and existing monitoring equipment is justified.

The next level of methodological stringency applies to large stationary combustion units that are fired with liquid or gaseous fuels. The stringency of the methods reflects the homogenous nature of these fuels and the ability to monitor fuel consumption more precisely. However, in cases where there is greater heterogeneity in the fuels (e.g., refinery fuel gas) more frequent analyses of liquid and gaseous fuels is required.

For smaller combustion units, EPA is proposing to allow the use of more simplified emissions calculation methods that rely on relationships between the heat content of the fuel (a generally known parameter) and the CO_2 emission factor associated with the fuel's characteristics.

The following subsections present EPA's proposed four-tiered approach in order from the most rigorous to the least stringent, and describe how it must be used by affected facilities. The applicability of the four measurement tiers, based on unit size and fuel type, is summarized in Table C–1 of this preamble. These CO_2 emission calculation methods would, in some cases, be applied at the unit level, and in other cases at the facility level (for further discussion, see ''Selection of Data Reporting Requirements'' below). Affected facilities would have the flexibility to use higher-tier methods (i.e., more stringent methods) than the ones required by this rule.

Tier 4. The Tier 4 methodology would require the use of certified CEMS to quantify CO_2 mass emissions, where existing CEMS equipment is installed. The existing installed CEMS must include a gas monitor of any kind or a flow monitor (or both). Generally, a CO_2 monitor and a stack gas volumetric flow rate monitor would be required to calculate CO_2 emissions, although in some cases, in lieu of a CO_2 concentration monitor, data from a certified oxygen (O_2) concentration monitor and fuel-specific F-factors could be used to calculate hourly CO_2 concentrations. An appropriate upgrade of the existing CEMS would be required: (1) If the gas monitor is neither a CO_2 concentration monitor nor an O_2 concentration monitor and (2) if a flow monitor is not already installed.

Any CEMS that would be used to quantify CO_2 emissions would also have to be certified and undergo on-going quality-assurance testing according to the procedures specified in either: (1) 40 CFR part 75; or (2) 40 CFR part 60, Appendix B; or (3) a State monitoring program.

The Tier 4 method, and the use of CEMS (with any required monitor upgrades), is required for solid fossil fuel-fired units with a maximum heat input capacity greater than 250 mmBtu/hr (and for units with a capacity to combust greater than 250 tons per day of MSW). The use of an O_2 monitor to determine CO_2 concentrations would not be allowed for units combusting MSW. EPA is unaware of carbon-based F-factors for MSW that would be appropriate for converting O_2 readings to CO_2 concentrations for this rule. Therefore, units combusting MSW would need to use a CO_2 monitor to calculate CO_2 emissions.

For smaller solid fossil fuel-fired units (i.e., less than or equal to 250 mmBtu/hr or 250 tons per day of MSW), EPA would require the use of Tier 4 if all the monitors needed to calculate CO_2 mass emissions (i.e., CO_2 gas monitor and flow monitor) are already installed, and certified and quality assured as described above.

In addition, in order to be subject to the Tier 4 requirements, the unit must have been operated for 1,000 hours or more in any calendar year since 2005.

The incremental cost of adding a diluent gas (CO_2 or O_2) monitor or a flow monitor, or both, to meet Tier 4 monitoring requirements would likely not be unduly burdensome for a large unit that combusts solid fossil fuels or MSW, operates frequently, and is already required to install, certify, maintain, and operate CEMS and to perform on-going QA testing of the existing monitors. The cost of compliance with the proposed rule would be even less for units that already have all of the necessary monitors in place. Cost estimates are provided in the RIA (EPA–HQ–OAR–2008–0508–002). In addition, EPA is allowing provisions to monitor common stack configurations. Please refer to Section V.C.5 of this preamble, on data reporting requirements, for further information on reporting where there are common stack configurations.

Reporters would follow the reporting requirements stated in proposed 40 CFR part 98, subpart A. However, EPA is allowing a January 1, 2011 compliance date to install CEMS to meet the Tier 4 requirements, if either a diluent gas monitor, flow monitor, or both, must be added. The January 1, 2011 deadline would allow sufficient time to purchase, install, and certify any additional monitor(s) needed to quantify CO_2 mass emissions. Until that time, affected units subject to that deadline would be allowed to use the Tier 3 methodology in 2010.

Tier 3. The Tier 3 calculation methodology would require periodic determination of the carbon content of the fuel, using consensus standards listed in the proposed 40 CFR part 98 (e.g., ASTM methods) and direct measurement of the amount of fuel combusted. This methodology is required for liquid and gaseous fossil fuel-fired units with a maximum heat input capacity greater than 250 mmBtu/hr, and is required for solid fossil fuel-fired units that are not subject to the Tier 4 provisions. In addition, EPA is proposing that a facility may use the Tier 3 calculation methodology to calculate facility-wide CO_2 emissions (rather than unit-by-unit emissions) when the same liquid or gaseous fuel is used across the facility and a common direct measurement of fuel consumed is available (e.g., a natural gas meter at the facility gate). This flexibility is consistent with existing protocols and methodologies allowed by EPA in existing programs. Please refer to the subsequent subsection on data reporting requirements for further information on the use of fuel data from common supply lines.

The required frequency for carbon content determinations for the Tier 3 calculation methodology would be monthly for natural gas, liquid fuels, and solid fuels (monthly molecular weight determinations are also required for gaseous fuels). Daily determinations for other gaseous fuels (e.g., refinery gas, process gas, etc.) would be required. The daily fuel sampling requirement for units that combust ''other'' gaseous fuels would likely not be overly burdensome, because the types of facilities that burn these fuels are likely to have equipment in place (e.g., on-line gas chromatographs) to continuously monitor the fuels' characteristics in order to optimize process operation. Solid fuel samples would be taken weekly and composited, but would only be analyzed once a month. Also, fuel sampling and analysis would be required only for those days or months when fuel is combusted in the unit.

For liquid and gaseous fuels, Tier 3 would require direct measurement of the amount of fuel combusted, using calibrated fuel flow meters. Alternatively, for fuel oil, tank drop measurements could be used. Solid fuel consumption would be quantified using company records. For quality-assurance purposes, EPA proposes that all oil and gas flow meters would have to be calibrated prior to the first reporting year. EPA recommends the use of the fuel flow meter calibration methods in 40 CFR part 75, but, alternatively, the manufacturer's recommended procedure could be used. Tank drop measurements and carbon content determinations would be made using the appropriate methods incorporated by reference.

Tier 2. The Tier 2 calculation methodology would require that the HHVs of each fuel combusted would be measured monthly. EPA is proposing that the Tier 2 method be used by units with heat input capacities of 250 mmBtu/hr or less, combusting fuels for which EPA has provided default CO_2 emission factors in the proposed rule. Fuel consumption would be based on company records. Please refer to the subsequent subsection on data reporting requirements for further information on the aggregation of units.

Tier 1. Under Tier 1, the annual CO_2 mass emissions would be calculated using the quantity of each type of fuel combusted during the year, in conjunction with fuel-specific default CO_2 emission factors and default HHVs. The amount of fuel combusted would be determined from company records. The default CO_2 emission factors and HHVs are national-level default factors. The Tier 1 method may be used by any small unit if EPA has provided the fuel-specific HHV and emission factors in proposed 40 CFR part 98, subpart C. However, if the owner or operator routinely performs fuel sampling and analysis on a monthly (or more frequent) basis to determine the HHV and other properties of the fuel, or if monthly HHV data are provided by the fuel supplier, Tier 1 could not be used but instead Tier 2 (or a higher tier) would have to be used.

EPA considered several alternative CO_2 emission calculation methods of varying stringency for stationary combustion units. The most stringent method would have required all combustion units at the affected facilities to use 40 CFR part 75 monitoring methodologies. However, this option was not pursued because it would have likely imposed an undue cost burden, particularly on smaller entities. For homogenous fuels, this additional cost burden would probably not lead to significant increases in accuracy compared with Tiers 1–3.

For coal combustion, EPA evaluated a number of calculation methods used in other mandatory and voluntary GHG emissions reporting programs. In general, these methods require relatively infrequent fuel sampling, do not take into account the heat input capacity of stationary combustion equipment, and use company records to estimate fuel consumption. Given the heterogeneous characteristics of coal, EPA determined that the procedures used in these other programs are not rigorous enough for this proposed rule and would introduce significant uncertainty into the CO_2 emissions estimates, especially for larger combustion units.

EPA considered allowing the use of default emission factors, default HHVs, and company records to quantify annual fuel consumption for all stationary combustion units, regardless of size or the type of fuel combusted. The Agency decided to limit the use of this type of calculation methodology to smaller combustion units. The proposed rule reflects this, by allowing use of the Tier 1 and Tier 2 calculation methodologies at units with a maximum heat input capacity of 250 mmBtu/hr or less.

For gaseous fuel combustion, EPA considered calculation methodologies based on an assumption that all gaseous fuels are homogeneous. However, the Agency decided against this approach because the characteristics of certain gaseous fuels can be quite variable, and mixtures of gaseous fuels are often heterogeneous in composition. Therefore, the proposed rule requires daily sampling for all gaseous fuels except for natural gas.

Finally, EPA considered allowing affected facilities to rely exclusively on the results of fuel sampling and analysis provided by fuel suppliers, rather than performing periodic on-site sampling for all variables. The Agency decided not to propose this because in most instances, only the fuel heating value, not the carbon content, is routinely provided by fuel suppliers. Therefore, EPA proposes to allow fuel suppliers to provide fuel HHVs for the Tier 2 calculation method. However, EPA is requesting comment on integrating the fuel supplier requirements of this proposed rule with both the Tier 1 and Tier 2 calculation methodologies.

b. CO_2 Emissions From Biomass Fuel Combustion

Today's proposed rule requires affected facilities with units that combust biomass fuels to report the annual biogenic CO_2 mass emissions separately. As previously described, this is consistent with the approach taken in the IPCC and national U.S. GHG inventory frameworks. EPA is proposing distinct methods to determine the biogenic CO_2 emissions from a stationary combustion source combusting a biomass or biomass-derived fuel depending upon which tier is used for reporting other fuel combustion CO_2 emissions.

Where Tier 4 is not required, EPA is allowing the Tier 1 method to be used to calculate biogenic CO_2 emissions for fuels in which EPA has provided default CO_2 emission factors and a default HHV in the proposed rule. If default values are not provided by EPA, the facility would use the Tier 2 or Tier 3 method, as appropriate, to calculate the biogenic CO_2 emissions.

For units required to use Tier 4, total CO_2 emissions are directly measured using CEMS. Except when MSW is combusted, EPA proposes that facilities perform a supplemental calculation to determine the biogenic CO_2 and non-biogenic CO_2 portions of the measured CO_2 emissions. The facility would use company records on annual fossil fuel combusted to calculate the annual volume of CO_2 emitted from that fossil fuel combustion. This value would then be subtracted from the total volume of CO_2 emissions measured to obtain the volume of biogenic CO_2 emissions. The volume ratio of biogenic CO_2 emissions to total CO_2 emissions would then be applied to the measured total CO_2 emissions to determine the biogenic CO_2 emissions.

c. CO_2 Emissions From MSW

EPA is proposing a separate calculation method for a unit that combusts MSW, which can include biomass components. For units subject to Tier 4, as described above, an additional analysis would be required to separately report any biogenic CO_2 emissions. The reporter would be required to use ASTM methods listed in the rule to sample and analyze the CO_2 in the flue gas once each quarter, in order to determine the relative percentages of fossil fuel-based carbon (e.g., petroleum-based plastics) and biomass carbon (e.g., newsprint) in the effluent when MSW is combusted in the unit. The measured ratio of biogenic to fossil CO_2 concentrations is then applied to the measured or calculated total CO_2 emissions to determine biogenic CO_2 emissions.

The GHG emission calculation methods for units combusting MSW would be used in conjunction with EPA's proposed calculation method for the annual unit heat input, based on steam production and the design characteristics of the combustion unit.

For units that combust MSW, EPA considered allowing a manual sorting approach to be used to determine the biomass and non-biomass fractions of the fuel, based on defined and traceable input streams. However, this approach is not considered practical, given the highly variable composition of MSW. To eliminate this uncertainty, EPA believes that more rigorous and standardized ASTM methods should be used to determine the biogenic percentage of the CO_2 emissions when MSW is combusted.

d. CH_4 and N_2O Emissions From All Fuel Combustion

As described previously, EPA is allowing simplified emissions calculation methods for CH_4 and N_2O. The annual CH_4 and N_2O emissions would be estimated using EPA-provided default emission factors and annual heat input values. The calculation would either be done at the unit level or the facility level, depending upon the tier required for estimating CO_2 emissions (and using the same heat input value reported from the CO_2 calculation method).

A CEMS methodology was not selected for measuring N_2O primarily because the cost impacts of requiring the installation of CEMS is high in comparison to the relatively low amount of N_2O emissions (even on a CO_2e basis) that would be emitted from stationary combustion equipment.

EPA considered requiring periodic stack testing to derive site-specific emission factors for CH_4 and N_2O. This approach has the advantage of ensuring a higher level of accuracy and consistency among reporters. However, it was decided that this option was too costly for the small improvement in data quality that it might achieve. The CH_4 and N_2O emissions from stationary combustion are relatively low compared to the CO_2 emissions. The proposed approach, i.e., using fuel-specific default emission factors to calculate CH_4 and N_2O emissions, is in accordance with methods used in other programs and provides data of sufficient accuracy. However, given the unit-level approach for calculating CO_2 emissions, EPA is requesting comments on the use of more technology-specific CH_4 and N_2O emission factors that could be applied in unit-level calculations.

e. CO_2 Emissions From Sorbent

For fluidized bed boilers and for units equipped with flue gas desulfurization systems or other acid gas emission controls with sorbent injection, CO_2 emissions would be accounted for and reported using simplified methods. These methods are based on the quantity of limestone or other sorbent material used during the year, if not accounted for using the Tier 4 calculation methodology.

In summary, EPA is proposing to allow facilities flexibility in measuring and monitoring stationary fuel combustion sources by: (1) Allowing most smaller combustion units (depending upon facility-level considerations described above) to use the Tier 1 and Tier 2 calculation methods; (2) allowing Tier 3 to be widely used, with few restrictions; (3) limiting the requirement to use Tier 4 to certain solid fuel-fired combustion units located at facilities where there is an established monitoring infrastructure; and (4) allowing simplified methodologies to calculate CH_4 and N_2O emissions. In addition, EPA is using a maximum heat input capacity determination of 250 mmBtu/hr to distinguish between large and small units. This approach is common to many existing EPA programs.

EPA believes that the proposed default CO_2 emission factors and high heat values used in Tiers 1 and 2 and the ASTM methods incorporated by reference for the carbon content determinations required by Tier 3 are well-established and minimize uncertainty.

In proposing this tiered approach, EPA acknowledges that, in the case of solid fuels, a simple, standardized way of measuring the amount of solid fuel combusted in a unit is not proposed. In view of this, the proposed rule would require the owner or operator to keep detailed records explaining how company records are used to quantify solid fuel usage. These records would describe the procedures used to calibrate weighing equipment and other measurement devices, and would include scientifically-based estimates of the accuracy of these devices. EPA therefore solicits comment on ways to ensure that the feed rate of solid fuel to a combustion device is accurately measured.

4. Selection of Procedures for Estimating Missing Data

The proposed rule requires the use of substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable, commonly referred to as ''missing data.'' For units using the CO_2 calculation methodologies in Tiers 2 and 3, when HHV, fuel carbon content, or fuel molecular weight data are missing, the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. When Tier 3 or Tier 4 is used and fuel flow rate or stack gas flow rate data is missing, the substitute data values would be the best available estimates of these parameters, based on process and operating data (e.g., production rate, load, unit operating time, etc.). This same substitute data approach would be used when fuel usage data and sorbent usage data are missing. The proposed rule provides that the reporter would be required to document and keep record of the procedures used to determine the appropriate substitute data values.

EPA considered more conservative missing data procedures for the proposed rule, such as requiring higher substitute data values for longer missing data periods, but decided against proposing these procedures out of concern that GHG emissions might be significantly overestimated.

5. Selection of Data Reporting Requirements

In addition to the facility-level information that would be reported under proposed 40 CFR part 98, subpart A, the proposed rule would require the reporter to submit certain unit-level data for the stationary combustion units at each affected facility. This additional information would require reporting of the unit type, its maximum rated heat input, the type of fuel combusted in the unit during the report year, the methodology used to calculate CO_2 emissions for each type of fuel combusted, and the total annual GHG emissions from the unit.

To reduce the reporting burden, the proposed rule would allow reporting of the combined GHG emissions from multiple units at the facility instead of requiring emissions reporting for each individual unit, in certain instances. Three types of emissions aggregation would be allowed. First, the combined GHG emissions from a group (or groups) of small units at a facility could be reported, provided that the combined maximum rated heat input of the units in the group does not exceed 250 mmBtu/hr. Second, the combined GHG emissions from units in a common stack configuration could be reported, if CEMS are used to continuously monitor the CO_2 emissions at the common stack. Third, if a facility combusts the same type of homogeneous oil or gaseous fuel through a common supply line, and the total amount of fuel consumed through that supply line is accurately measured using a calibrated fuel flow meter, the combined GHG emissions from the facility could be reported.

Different levels of verification data are required depending upon which tier is used for reporting. For Tier 1, only the total quantity of each type of fuel combusted during the report year would be reported. For Tier 2, the quantity of each type of fuel combusted during each measurement period would be reported, along with all high heat values used in the emissions calculations, the methods used to determine the HHVs, and information indicating which HHVs (if any) are substitute data values.

For Tier 3, the quantity of each type of fuel combusted during each measurement period (day or month) would be reported, along with all carbon content values and, if applicable, molecular weight measurements used in the emissions calculations, with information indicating which ones (if any) are substitute data values. In addition, the results of all fuel flow meter calibrations would be reported along with information indicating which analytical methods were used for the carbon content determinations, flow meter calibrations and (if applicable) oil tank drop measurements.

For Tier 4, the number of unit operating days and hours would be reported, along with daily CO_2 mass emission totals, the number of hours of substitute data used in the annual emissions calculations, the results of the initial CEMS certification tests and the major ongoing QA tests.

If MSW is combusted in the unit, the owner or operator would be required to report the results of the quarterly sample analyses used to determine the biogenic percentage of CO_2 emissions in the effluent. If combinations of fossil and biomass fuels are combusted and CEMS are used to measure CO_2 emissions, the annual volumes of biogenic and fossil CO_2 would be reported, along with the F-factors and fuel gross calorific values used in the calculations, and the biogenic percentage of the annual CO_2 emissions.

Finally, for units that use acid gas scrubbing with sorbent injection but are not equipped with CEMS, the owner or operator would be required to report information on the type and amount of sorbent used.

6. Selection of Records That Must Be Retained

In addition to meeting the general recordkeeping requirements in proposed 40 CFR part 98, subpart A, whenever company records are used to estimate fuel consumption (e.g., when the Tier 1 or 2 emissions calculation methodology is used) and sorbent consumption, EPA proposes to require the owner or operator to keep on file a detailed explanation of how fuel usage is quantified, including a description of the QA procedures that are used to ensure measurement accuracy (e.g., calibration of weighing devices and other instrumentation).

As discussed in Section IV of this preamble and proposed 40 CFR part 98, subpart A, there are a number of facilities that are not part of a source category listed in 40 CFR 98.2(1)(a) or (2) but have stationary combustion equipment emitting GHG emissions. In 2010, those facilities would have to determine whether or not they are subject to the requirements of this rule (i.e., if their emissions are 25,000 metric tons CO_2e/yr or higher). In order to reduce the burden on those facilities, we are proposing that facilities with an aggregate maximum heat input capacity of less than 30 mmBtu/hr from stationary combustion units are automatically exempt from the proposed 40 CFR part 98. Based on our assessment of the maximum amount of GHG emissions likely from units of that size that burn fossil fuels (e.g, coal, oil or gas) and operate continuously through the year, such a facility would still be below the 25,000 metric tons CO_2e threshold. The purpose for having this provision is to exempt small facilities from having to estimate emissions to determine if they are subject to the rule, and re-estimate whenever there are process changes.

D. Electricity Generation

1. Definition of the Source Category

This section of the preamble addresses GHG emissions reporting for facilities with EGUs that are in the ARP, and are subject to the CO_2 emissions reporting requirements of Section 821 of the CAA Amendments of 1990. All other facilities using stationary fuel combustion equipment to generate electricity should refer to Section V.C of this preamble (General Stationary Fuel Combustion Sources) to understand EPA's proposed approach for GHG emissions reporting.

Electricity generating units in the ARP reported CO_2 emissions of 2,262 million metric tons CO_2e in 2006. This represents almost one third of total U.S. GHG emissions and over 90 percent of CO_2 emissions from electricity generation. EPA has been receiving these CO_2 data since 1995.[64]

2. Selection of Reporting Threshold

If a facility includes within its boundaries at least one EGU that is subject to the ARP, the facility would be subject to the mandatory GHG emissions reporting of proposed 40 CFR part 98, subpart D. Facilities with EGUs in the ARP would not be expected to report any new CO_2 data. Therefore, EPA expects that the GHG emissions reporting requirements of this rule would not be overly burdensome for facilities already reporting to the ARP.

For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

For ARP units, the CO_2 mass emissions data already reported to EPA under 40 CFR part 75 would be used in the annual GHG emissions reports required under this proposed rule. The annual CO_2 mass emissions (i.e., English short tons) reported for an ARP unit would simply be converted to metric tons and then included in the GHG emissions report for the facility.

As CH_4 and N_2O emissions are not required to be reported under 40 CFR part 75, the facility would consult the proposed methods in proposed 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources) for calculating CH_4 and N_2O from the ARP units.

The additional units at an affected facility that are not in the ARP would use the GHG calculation methods specified and required in proposed 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

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[64] This data can be accessed at: *http://epa.gov/camdataandmaps.*

4. Selection of Procedures for Estimating Missing Data

The proposed missing data substitution procedures for CH_4 and N_2O emissions from ARP units and all GHG emissions from units at the facility not in ARP are discussed in Section V.C.4 of this preamble, under General Stationary Fuel Combustion Sources.

5. Selection of Data Reporting Requirements

The proposed data reporting requirements are discussed in Section V.C.5 of this preamble, under General Stationary Fuel Combustion Sources.

6. Selection of Records That Must Be Retained

The records that must be retained regarding CH_4 and N_2O emissions from ARP units and all GHG emissions from units at the facility not in the ARP are discussed in Section V.C.6 of this preamble, under General Stationary Fuel Combustion Sources.

E. Adipic Acid Production

1. Definition of the Source Category

Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters. Adipic acid is also used in food applications.

Adipic acid is produced through a two-stage process. The first stage usually involves the oxidation of cyclohexane to form a cyclohexanone/cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid.

National emissions from adipic acid production were estimated to be 9.3 million metric tons CO_2e (less than 0.1 percent of U.S. GHG emissions) in 2006. These emissions include both process-related emissions (N_2O) and on-site stationary combustion emissions (CO_2, CH_4, and N_2O). The main GHG emitted from adipic acid production is N_2O, which is generated as a by-product of the nitric acid oxidation stage of the manufacturing process, and it is emitted in the waste gas stream. Process N_2O emissions alone were estimated at 5.9 million metric tons CO_2e, or 64 percent of the total GHG emissions in 2006, while on-site stationary combustion emissions account for the remaining 3.4 million metric tons CO_2e, or 36 percent of the total.

Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. DE for N_2O emissions can vary from 90 to 98 percent using abatement technologies such as nonselective catalytic reduction. In 1998, the three major adipic acid production facilities in the U.S. had control systems in place. Only one small facility, representing approximately two percent of adipic acid production, does not control for N_2O.

As part of this proposed rule, stationary combustion emissions would be estimated and reported according to the applicable procedures in proposed 40 CFR part 98, subpart C. For additional background information on adipic acid production, please refer to the Adipic Acid Production TSD (EPA–HQ–OAR–2008–0508–005).

2. Selection of Reporting Threshold

In developing the threshold for adipic acid production, we considered emissions-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. Table E–1 of this preamble illustrates that the various thresholds do not affect the amount of emissions or number of facilities that would be covered.

TABLE E–1. THRESHOLD ANALYSIS FOR ADIPIC ACID PRODUCTION

Threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	9,300,000	4	9,300,000	100	4	100
10,000	9,300,000	4	9,300,000	100	4	100
25,000	9,300,000	4	9,300,000	100	4	100
100,000	9,300,000	4	9,300,000	100	4	100

Facility-level emissions estimates based on known facility capacities for the four known adipic acid facilities suggests that each of the facilities would be at least five times over the 100,000 metric tons CO_2e threshold based on just process-related emissions. Because all adipic acid production facilities would have to report under any of the emission thresholds that were examined, we propose that all adipic acid production facilities be required to report. This would simplify rule applicability and avoid any burden for the source to perform unnecessary calculations.

For a full discussion of the threshold analysis, please refer to the Adipic Acid Production TSD (EPA–HQ–OAR–2008–0508–005). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating adipic acid production process emissions (e.g., 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), and TRI). These methodologies coalesce around the four options discussed below.

Option 1. Default emission factors would be applied to total facility production of adipic acid. The emissions would be calculated using the total production of adipic acid and the highest international default emission factor available in the 2006 IPCC Guidelines. This option assumes no abatement of N_2O emissions. This approach is consistent with IPCC Tier 1 and the DOE 1605(b) ''C'' rated estimation method.

Option 2. Default emission factors would be applied on a site-specific basis using the specific type of abatement technology used and the adipic acid production activity. The amount of N_2O emissions would be determined by multiplying the technology-specific emission factor by the production level of adipic acid. This approach is consistent with 1605(b) ''B'' rated estimation method, IPCC Tier 2, and TCR's ''B'' rated estimation method.

Option 3. Periodic direct emission measurement of N_2O emissions would be used to determine the relationship between adipic acid production and the amount of N_2O emissions; i.e., to develop a facility-specific emissions factor. The facility-specific emissions factor and production rate (activity level) would be used to calculate the emissions. The facility-specific emission factor would be developed from a single annual test. Production rate is most likely already measured at facilities. Existing procedures would be followed to measure the production rate during the performance test and on a quarterly basis thereafter. After the initial test, annual testing of N_2O emissions would be required each year to estimate the emission factor and applied to production to estimate emissions. The yearly testing would assist in verifying the emission factor. Testing would also be required whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test. Option 3 and the following Option 4 are approaches consistent with IPCC Tier 3, DOE 1605(b) ''A'' and TCR's ''A2'' rated estimation methods.

Option 4. CEMS would be used to directly measure the N_2O process emissions. CEMS would be used to directly measure N_2O concentration and flow rate to directly determine N_2O emissions. Measuring N_2O emissions directly with CEMS is feasible, but adipic acid production facilities are currently only using NO_X CEMS to comply with State programs (e.g. Texas). Half of the adipic acid production facilities are located in Texas where NO_X CEMS are required in O_3 nonattainment areas under Control of Air Pollution from Nitrogen Compounds (TX Chap 117 (Reg 7)).

Proposed option: We propose Option 3 to quantify process emissions from all adipic acid facilities. In addition, you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion.

We identified Options 3 and 4 as the approaches providing the lowest uncertainty and the best site-specific estimates based on differences in process operation and abatement technologies. Option 3 requires annual monitoring of N_2O emissions and the establishment of a facility-specific emissions factor that relates N_2O emissions with adipic acid production rate.

Option 4 was not chosen as the required method because, while N_2O CEMS are available, there is no existing EPA method for certifying N_2O CEMS, and the cost impact of requiring the installation of CEMS is high in comparison to the relatively low amount of emissions that would be quantified from the adipic acid production sector. NO_X CEMS only capture emissions of NO and NO_2 and not N_2O. Although the amount of NO_X and N_2O emissions from adipic acid production may be directly related, direct measurement of NO_X does not automatically correlate to the amount of N_2O in the same exhaust stream. Periodic testing of N_2O emissions (Option 3) would not indicate changes in emissions over short periods of time, but it does offer direct measurement of GHGs.

We request comment on the advantages and disadvantages of using Options 3 and 4. After consideration of public comments, we may promulgate one or more of these options or a combination based on the additional information that is provided.

We decided against Options 1 and 2 because facility-specific emission factors are more appropriate for reflecting differences in process design and operation. According to IPCC, the default emission factors for adipic acid are relatively certain because they are derived from the stoichiometry of the chemical reaction employed to oxidize nitric acid. However, there is still uncertainty in the amount of N_2O that is generated. This variability is a result of differences in the composition of cyclohexanone and cyclohexanol feedstock. Variability also arises if adipic acid is produced from use of other feedstocks, such as phenol or hydrogen peroxide. Facility-specific emission factors would be based on actual feedstock composition rather than an assumed composition.

The various approaches to monitoring GHG emissions are elaborated in the Adipic Acid Production TSD (EPA–HQ–OAR–2008–0508–005).

4. Selection of Procedures for Estimating Missing Data

For process sources that use Option 3 (facility-specific emission factor), no missing data procedures would apply because the facility-specific emission factor is derived from an annual performance test and used in each calculation. The emission factor would be multiplied by the production rate, which is readily available. If the test data are missing or lost, the test would have to be repeated. Therefore, 100 percent data availability would be required.

5. Selection of Data Reporting Requirements

We propose that facilities submit their total annual N_2O emissions from adipic acid production, as well as any stationary fuel combustion emissions. In addition we propose that facilities submit the following data, which are the basis of the calculations and are needed to understand the emissions data and verify the reasonableness of the reported emissions. The data submitted on an annual basis should include annual adipic acid production capacity, total adipic acid production, facility-specific emission rate factor used, abatement technology used, abatement technology efficiency, abatement utilization factor, and number of facility operating hours in calendar year.

Capacity, actual production, and operating hours support verification of the emissions data provided by the facility. The production rate can be determined through sales records or by direct measurement using flow meters or weigh scales. This industry generally measures the production rate as part of normal operating procedures.

A list of abatement technologies would be helpful in assessing the widespread use of abatement in the adipic acid source category, cataloging any new technologies that are being used, and documenting the amount of time that the abatement technologies are being used.

A full list of data to be reported is included in the proposed 40 CFR part 98, subparts A and E.

6. Selection of Records That Must Be Retained

We propose that facilities maintain records of annual testing of N_2O emissions, calculation of the facility-specific emission rate factor, hours of operation, annual adipic acid production, adipic acid production capacity, and N_2O emissions. These records hold values directly used to calculate the emissions that are reported and are necessary to allow determination of whether the GHG emissions monitoring calculations were done correctly. A full list of records that must be retained on site is included in the proposed 40 CFR part 98, subparts A and E.

F. Aluminum Production

1. Definition of the Source Category

This source category includes primary aluminum production facilities. Secondary aluminum production facilities would not be required to report emissions under Subpart F. Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in manufactured products in many sectors including transportation, packaging, building and construction. As of 2005, the U.S. was the fourth largest producer of primary aluminum, with approximately eight percent of the world total (Aluminum Production TSD

(EPA–HQ–OAR–2008–0508–006)). The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of CO_2 and two PFCs: perfluoromethane (CF_4) and perfluoroethane (C_2F_6). Only these process-related emissions are discussed here. Stationary fuel combustion source emissions must be monitored and reported according to proposed 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), which is discussed in Section V.C of this preamble.

CO_2 is emitted during the primary aluminum smelting process when alumina (aluminum oxide, Al_2O_3) is reduced to aluminum using the Hall-Héroult reduction process. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na_3AlF_6). The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a carbon mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During reduction, most of the carbon in the anode is oxidized and released to the atmosphere as CO_2. In addition, a smaller amount of CO_2 is released during the baking of anodes for use in smelters using prebake technologies.

In addition to CO_2 emissions, the primary aluminum production industry is also a source of PFC emissions. During the smelting process, if the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed ''anode effects.'' These anode effects cause carbon from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing emissions of CF_4 and C_2F_6. For any particular individual smelter, the magnitude of emissions for a given level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase. In addition, even at constant levels of production and anode effect minutes, emissions vary among smelter technologies (e.g., Center-Work Prebake vs. Side-Work Prebake) and among individual smelters using the same smelter technology due to differing operational practices.

Total U.S. Emissions. According to the U.S. GHG Inventory total process-related GHG emissions from primary aluminum production in the U.S. are estimated to be 6.4 million metric tons CO_2e in 2006. Process emissions of CO_2 from the 14 aluminum smelters in the U.S. were estimated to be 3.9 million metric tons CO_2e in 2006. Process emissions of CF_4 and C_2F_6 from aluminum smelters were estimated to be 2.5 million metric tons CO_2e in 2006. In 2006, 13 of the 14 primary aluminum smelters in the U.S. accounted for the vast majority of primary aluminum emissions. The remaining smelter was idle through most of 2006, restarting at the end of the year.

Emissions to be reported. We propose to require reporting of the following types of emissions from primary aluminum production: Process emissions of PFCs, process emissions of CO_2 from consumption of the anode during electrolysis (for both Prebake and Søderberg cells), and process emissions of CO_2 from the anode baking process (for Prebake cells only).

Another potential source of process CO_2 emissions is coke calcining. We request comment on whether any U.S. smelters operate calcining furnaces and the extent of these process emissions.

2. Selection of Reporting Threshold

We propose to require all owners or operators of primary aluminum facilities to report the total quantities of PFC and CO_2 process emissions. In 2006, 5 companies operated 14 primary aluminum for at least part of the year. (One of these smelters operated only briefly at the end of the year.) All primary aluminum smelters that operated throughout 2006 would be covered at all capacity and emissions-based thresholds considered in this analysis.

In developing the threshold for primary aluminum, we considered the emissions thresholds 1,000, 10,000, 25,000, and 100,000 metric tons CO_2e per year (metric tons CO_2e/yr). These emissions thresholds translate to 64, 640, 1,594, and 6,378 metric tons primary aluminum produced, respectively, based on use of the 2006 IPCC default emission factors and assuming side-worked prebake cells and 100 percent capacity utilization as shown in Table F–1 of this preamble.

TABLE F–1. THRESHOLD ANALYSIS FOR ALUMINUM PRODUCTION BASED ON 2006 EMISSIONS AND FACILITY PRODUCTION CAPACITY

Emission threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	6,402,000	14	6,402,000	100	14	100
10,000	6,402,000	14	6,397,000	99.9	13	93
25,000	6,402,000	14	6,397,000	99.9	13	93
100,000	6,402,000	14	6,397,000	99.9	13	93
Production Capacity Threshold metric tons Al/year						
64	6,402,000	14	6,402,000	100	14	100
640	6,402,000	14	6,402,000	100	14	100
1,594	6,402,000	14	6,402,000	100	14	100
6,378	6,402,000	14	6,402,000	100	14	100

We propose that all primary aluminum facilities be subject to reporting. All smelters that operated in 2006 would be required to report if a 10,000, 25,000, or 100,000 metric tons CO_2e per year threshold were used. Requiring all facilities to report would simplify the rule, avoid the need for facilities to estimate emissions to determine applicability, and ensure complete coverage of emissions from this source category. It results in little extra burden for the industry since few if any additional facilities would be required to report (compared to the thresholds considered). Significant fluctuations in capacity utilization do occur; aluminum smelters sometimes shut down for long periods. Under the proposed rule, facilities that did not operate at all during the previous year would still have to submit a report; however, reporting would be minimal. (Zero production implies zero emissions.)

For a full discussion of the threshold analysis, please refer to the Aluminum Production TSD (EPA–HQ–OAR–2008–0508–006). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

This section of this preamble provides monitoring methods for calculating and reporting process CO_2 and PFC emissions only. If a facility has stationary fuel combustion it would need to also refer to proposed 40 CFR part 98, subpart C for methods for CO_2, CH_4 and N_2O and would be required to follow the calculation procedures, monitoring and QA/QC methods, recordkeeping requirements as described.

Protocols and guidance reviewed for this analysis include the 2006 IPCC Guidelines, EPA's Voluntary Aluminum Industrial Partnership, the Inventory of U.S. Greenhouse Gas Emissions and Sinks, the International Aluminum Institute's Aluminum Sector Greenhouse Gas Protocol, the Technical Guidelines for the Voluntary Reporting of Greenhouse Gases (1605(b)) Program, EPA's Climate Leaders Program, and TRI.

The methods described in these protocols and guidance coalesce around the methods described by the International Aluminum Institute's Aluminum Sector Greenhouse Gas Protocol and the 2006 IPCC Guidelines. These methods range from Tier 1 approaches based on aluminum production to Tier 3 approaches based primarily on smelter-specific data. The IPCC Tier 3 and International Aluminum Institute methods are essentially the same.

Proposed Method for Monitoring PFC Emissions. The proposed method for monitoring PFC emissions from aluminum processing is similar to the Tier 3 approach in the 2006 IPCC Guidelines for primary aluminum production. The proposed method requires smelter-specific data on aluminum production, anode effect minutes per cell day (anode effect-mins/cell-day), and recently measured slope coefficients. The slope coefficient represents kg of CF_4/metric ton of aluminum produced divided by anode effect minutes per cell-day. The cell-day is the number of cells operating multiplied by the number of days of operation, per the 2006 IPCC Guidelines. The following describes how to calculate CF_4 and C_2F_6 emissions based on the slope method. CF_4 emissions equal the slope coefficient for CF_4 (kg CF_4/metric ton Al)/anode effect-Mins/cell-day) times metal production (metric tons Al). Annual anode effect calculations and records should be the sum of anode effect minutes per cell day and production by month. C_2F_6 emissions equal emissions of CF_4 times the weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

Both the IPCC Tier 3 method and the less accurate IPCC Tier 2 method are based on these equations and parameters. The critical distinction between the two methods is that the Tier 3 method requires smelter-specific slope coefficients while the Tier 2 method relies on default, technology-specific slope coefficients. Of the currently operating U.S. smelters, all but one has measured a smelter-specific coefficient at least once. However, as discussed below, some smelters may need to update these measurements if they occurred more than 3 years ago.

Use of the Tier 3 approach significantly improves the precision of a smelter's PFC emissions estimate. For individual facilities using the most common smelter technology in the U.S., the uncertainty (95 percent confidence interval) of estimates developed using the Tier 2 approach is ±50 percent,[65] while the uncertainty of estimates developed using the Tier 3 approach is approximately ±15 percent (Aluminum Production TSD (EPA–HQ–OAR–2008–0508–006)). For a typical U.S. smelter emitting 175,000 metric tons CO_2e in PFCs, these errors result in absolute uncertainties of ±88,000 metric tons CO_2e and ±26,000 metric tons CO_2e, respectively. The reduction in uncertainty associated with moving from the Tier 2 to the Tier 3 approach, 62,000 metric tons CO_2e, is as large as the emissions from many of the sources that would be subject to the rule. We concluded the extra burden to facilities of measuring the smelter-specific slope coefficients is justified by the considerable improvement in the precision of the reported emissions.

Measurement of Slope Coefficients. We propose that slope coefficients be measured using a method similar to the USEPA/International Aluminum Institute Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane from Primary Aluminum Production. The protocol 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). These guidelines include recommendations for documenting the frequency and duration of anode effects, measuring aluminum production, sampling design, measurement instruments and methods, calculations, QA/QC, and measurement frequency.

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.[66] 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.

We understand that two smelting companies in the U.S., Rio Tinto Alcan and Alcoa, have the necessary equipment and teams in-house to measure smelter-specific slope factors. These two companies account for 11 out of 15 of the operating smelters in the U.S. The remaining facilities would need to hire a consultant to conduct a measurement study once every three years to accurately determine their slope coefficients. The cost of hiring a consultant to conduct the measurement study is probably significantly lower than the capital, labor and O&M costs of the equipment, training, and maintenance required to conduct the measurements in-house. While the cost to implement a Tier 3 approach is significantly greater than the cost to implement a Tier 2 approach, the benefit of reduced uncertainty is considerable (approximately 40 percent), as noted above.

We request comment on the proposal that all smelters be required to measure their smelter-specific slope coefficients at least once every three years. We considered, but are not proposing, to exempt ''high performing'' smelters, as defined by the 2006 IPCC Guidelines, from the requirement to measure their smelter-specific slope coefficients more

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[65] The most common smelter technology in the U.S. is the center-worked prebake technology. The 2006 IPCC Guidelines provide a 95 percent confidence interval of ±6 percent for the center-worked prebake technology default slope coefficient. However, this range is not the range within which the slope coefficient from a single center-worked prebake technology has a 95 percent chance of falling. Instead, it is the range within which the true mean of all center-worked prebake technology slope factors has a 95 percent chance of falling. This appears to depart from the usual convention for expressing the uncertainties related to the use of default coefficients in the Guidelines.

[66] Aluminum Production TSD (EPA–HQ–OAR–2008–0508–006).

than once. The Guidelines define ''high-performing'' smelters as those that operate with less than 0.2 anode effect minutes per cell day or less than 1.4 millivolt overvoltage. The Guidelines state, ''no significant improvement can be expected in the overall facility GHG inventory by using the Tier 3 method rather than the Tier 2 method.'' (IPCC, page 4.53, footnote 1). However, EPA believes there is benefit to EPA and to industry of periodic evaluation of the correlation of the smelter-specific slope coefficient and actual emissions, even in situations of low anode effect minutes per cell day or overvoltage.

The Overvoltage Method. Another Tier 3 method included in the IPCC Guidelines is the Overvoltage Method. This 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. We request comment on whether any U.S. smelters are using the Pechiney technology and, if so, on whether these smelters should be permitted to use the Overvoltage Method.

Proposed Method for Monitoring Process CO_2 *Emissions.* If you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate stationary fuel combustion CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate process and stationary fuel combustion CO_2 emissions from the industrial source. Also, refer to proposed 40 CR part 98, subpart C to estimate combustion-related CH_4 and N_2O.

If your facility does not have stationary combustion, or if you do not currently have CEMS that meet the requirements outlined in proposed 40 CR part 98, subpart C, or where the CEMS would not adequately account for process CO_2 emissions, the proposed monitoring method for process CO_2 emissions is similar to the IPCC Tier 2 approach, which relies on industry defaults rather than smelter-specific values for concentrations of minor anode components.

CO_2 emitted during electrolysis. We propose to require that CO_2 emitted during electrolysis be calculated based on metal production and net anode consumption using a mass balance approach that assumes all carbon from net anode consumption is ultimately emitted as CO_2. Since the concentrations of the non-carbon components are small (typically less than one percent to five percent), facility-specific data on them is not as critical to the precision of emission estimates as is facility-specific data on net anode consumption. Tier 3 improves the accuracy of the results but the improvement in accuracy is not expected to exceed 5 percent per the 2006 IPCC Guidelines. Although we do not propose to require the use of the Tier 3 approach, we would allow and encourage smelter operators to use facility-specific data on anode non-carbon components when that data were available.

For prebake cells, CO_2 emissions are equal to net prebaked anode consumption per metric ton aluminum times total metal production times the percent weight of sulfur and ash content in the baked anode times the molecular mass of CO_2.

CO_2 emissions from Søderberg cells are a function of total metal production, paste consumption, emissions of cyclohexane soluble matter, percent binder and sulfur content in paste, percent ash and hydrogen content in pitch, percent weight of sulfur and ash content in calcined coke, carbon in skimmed dust from Søderberg cells, and the carbon atomic mass ratio.

The data reported by companies participating in EPA's Voluntary Aluminum Industrial Partnership has generally not included smelter-specific values for each of these variables. However, most participants in the Voluntary Aluminum Industrial Partnership have used either data on paste consumption (for Søderberg cells) or on net anode consumption (for Prebake cells), along with some smelter-specific data on impurities, to develop a hybrid IPCC Tier 2/3 estimate (i.e., combination of smelter-specific and default factors).

CO_2 emitted during anode baking. We propose that CO_2 emitted during anode baking be calculated based on a mass balance approach involving chemical contents of the anodes and packing materials. No anode baking emissions occur when using Søderberg cells, since these cells are not baked before aluminum smelting, but rather, bake in the electrolysis cell during smelting.

CO_2 emissions from pitch volatiles combustion equal the initial weight from green anode minus hydrogen content minus baked anode production minus waste tar collected times the molecular weight of CO_2. CO_2 emissions from bake furnace packing material are a function of packing coke consumption times baked anode production times the percent weight sulfur and ash content in packing coke.

As is the case for CO_2 emitted during electrolysis, the IPCC Tier 2 approach for anode baking relies on industry-wide defaults for minor anode components, requiring smelter-specific data only for the initial weight of green anodes and for baked anode production. The IPCC Tier 3 approach requires smelter-specific values for all parameters. Again, the concentrations of minor components are small, limiting their impact on the estimate of CO_2 emissions from anode baking. In addition, anode baking emissions account for approximately 10 percent of total CO_2 process emissions, so reducing the uncertainty in this estimate would have only a minor impact on the overall CO_2 process estimate. For EPA's Voluntary Aluminum Industrial Partnership program, many smelters report only some smelter-specific values for the concentrations of minor anode components. In light of these considerations, we propose to require the Tier 2 method for estimating CO_2 emissions from anode baking, with the option to use facility-specific data on impurity concentrations when that data is available.

Other Options Considered. We are not proposing IPCC's Tier 1 methodology for calculating PFC emissions. Although this methodology is simple, the default emission factors for PFCs have large uncertainties due to the variability in anode effect frequency and duration. Since 1990, all U.S. smelters have sharply reduced their anode effect frequency and duration; through 2006, average anode minutes per cell day have declined by approximately 85 percent, lowering U.S. smelter emission rates well below those of the IPCC Tier 1 defaults. Consequently, as discussed above, the Tier 3 methodology has been proposed.

For CO_2, we are not proposing IPCC's Tier 1 methodology for calculating emissions. The difference in uncertainty between emission estimates developed using IPCC Tier 1 and Tier 2/3 approaches for U.S. smelters is notably lower than the difference for the PFC estimates. However, as part of typical operations, facilities regularly monitor inputs to higher Tier methods (e.g., consumption of anodes); consequently, the incremental cost to use the IPCC Tier 2 or a Tier 2/3 hybrid estimate are small.

4. Selection of Procedures for Estimating Missing Data

Where anode effect minutes per cell day data points are missing, the average anode effect minutes per cell day of the remaining measurements within the same reporting period may be applied. These parameters are typically logged by the process control system as part of the operations of nearly all aluminium production facilities and the uncertainties in these data are low.

It is likely that aluminum production levels would be well known, since businesses rely on accurate monitoring and reporting of production levels. The 2006 IPCC Guidelines specify an uncertainty of less than 1 percent in the data for the annual production of aluminum. The likelihood for missing data is low.

For CO_2 emissions, the uncertainty in recording anode consumption as baked anode consumption or coke consumption is estimated to be only slightly higher than for aluminium production, less than 2 percent per the 2006 IPCC Guidelines. This is also an important parameter in smelter operations and is routinely/continuously monitored. Again, the likelihood for missing data is low.

5. Selection of Data Reporting Requirements

In addition to annual GHG emissions data, facilities would be required to submit annual aluminum production and smelter technology used. The following PFC-specific information would also be required to be reported on an annual basis: Anode effect minutes per cell-day, and anode effect frequency and duration. Smelters would also be required to submit smelter-specific slope coefficient; the last date when smelter-specific slope coefficient was measured; certification that measurements of slope coefficients were conducted in accordance with the method identified in proposed 40 CFR part 98, subpart F; and the parameters used by the smelter to measure the frequency and duration of anode effects.

The following CO_2-specific information would be reported on an annual basis: Anode consumption for pre-bake cells, paste consumption for Søderberg cells, and smelter-specific inputs to the CO_2 process equations (e.g., levels of impurities) that were used in the calculation. Exact data elements required would vary depending on smelter technology.

These records consist of values that are used to calculate the emissions and are necessary to enable verification that the GHG emissions monitoring and calculations were done correctly.

6. Selection of Records That Must Be Retained

In addition to the data reported, we propose that facilities maintain records on monthly production by smelter, anode effect minutes per cell-day or anode effect overvoltage by month, facility specific emission coefficient linked to anode effect performance, and net anode consumption for Prebake cells or paste consumption for Søderberg cells.

These records consist of data that would be used to calculate the GHG emissions and are necessary to verify that the emissions monitoring and calculations are done correctly.

G. Ammonia Manufacturing

1. Definition of the Source Category

Ammonia is a major industrial chemical that is mainly used as fertilizer, directly applied as anhydrous ammonia, or further processed into urea, ammonium nitrates, ammonium phosphates, and other nitrogen compounds. Ammonia also is used to produce plastics, synthetic fibers and resins, and explosives.

Ammonia can be produced through three processes: Steam reforming, solid fuel gasification, and brine electrolysis. The production of ammonia typically uses conventional steam reforming or solid fuel gasification and generates both combustion and process-related greenhouse gas emissions. The production of ammonia through the brine electrolysis process does not produce process GHG emissions, although it releases GHGs from combustion of fuels to support the electrolysis process. We have not identified any facilities in the U.S. producing ammonia through the brine electrolysis process.

Catalytic steam reforming of ammonia generates process-related CO_2, primarily through the use of natural gas as a feedstock. One plant located in Kansas is manufacturing ammonia from petroleum coke feedstock. This and other natural gas-based and petroleum coke-based feedstock processes produce CO_2 and hydrogen, the latter of which is used in the manufacture of ammonia.

Not all of the CO_2 produced in the manufacture of ammonia is emitted directly to the atmosphere. Both ammonia and CO_2 are used as raw materials in the production of urea ($CO(NH_2)_2$), which is another type of nitrogenous fertilizer that contains carbon (C) and nitrogen (N). The carbon from ammonia production that is used to manufacture urea is assumed to be released into the environment as CO_2 during urea use. Therefore, the majority of CO_2 emissions associated with urea consumption are those that result from its use as a fertilizer. For CO_2 collected and used onsite or transferred offsite, you must follow the methodology provided in proposed 40 CFR part 98, subpart PP (Suppliers of CO_2).

Some facilities produce for sale a combination of ammonia, methanol, and hydrogen. We propose that facilities report their process-related GHG emissions in the source category corresponding to the primary NAICS code for the facility. For example, a facility that primarily produces ammonia but also produces methanol would report in the ammonia manufacturing source category. Since CO_2 is used to produce methanol, it does not get emitted directly into the atmosphere. These facilities would account for the CO_2 used to produce methanol through the methodology provided in proposed 40 CFR part 98, subpart G (Ammonia Manufacturing).

National emissions from ammonia manufacturing were estimated to be 14.6 million metric tons CO_2 equivalent (<0.25 percent of U.S. GHG emissions in 2006). These emissions include both process related CO2 emissions and on-site stationary combustion emissions (CO_2, CH_4, and N_2O) from 24 manufacturing facilities across the U.S. Process-related emissions account for 7.6 million metric tons CO_2, or 52 percent of the total, while on-site stationary combustion emissions account for the remaining 7.0 million metric tons CO_2 equivalent emissions.

For additional background information on ammonia manufacturing, please refer to the Ammonia Manufacturing TSD (EPA–HQ–OAR–2008–0508–007).

2. Selection of Reporting Threshold

In developing the reporting threshold for ammonia manufacturing, we considered emissions-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. Table G–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE G–1. THRESHOLD ANALYSIS FOR AMMONIA MANUFACTURING

Threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	14,543,007	24	14,543,007	100	24	100
10,000	14,543,007	24	14,543,007	100	24	100
5,000	14,543,007	24	14,543,007	100	24	100
100,000	14,543,007	24	14,449,519	99	22	92

Facility-level emissions estimates based on known plant capacities suggest that all known facilities, except two, exceed the 100,000 metric tons CO_2e threshold. Where information was available, emission estimates were adjusted to account for CO_2 consumption during urea production, and this was taken into account in the threshold analysis. In order to simplify the proposed rule and avoid the need for the source to calculate and report whether the facility exceeds the threshold value, we propose that all ammonia manufacturing facilities are required to report.

For a full discussion of the threshold analysis, please refer to the Ammonia Manufacturing TSD (EPA–HQ–OAR–2008–0508–007). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international monitoring guidelines and protocols include methodologies for estimating both combustion and process-related emissions from ammonia manufacturing (e.g., 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), and TCR). These methodologies coalesce around the following four options which we considered for quantifying emissions from ammonia manufacture:

Option 1. The first method found in existing protocols estimates emissions by applying a default emission factor to total ammonia produced. This approach estimates only process-related emissions. This approach is consistent with IPCC Tier 1 and DOE 1605(b) ‘‘C’’ rated estimation methods.

Option 2. A second method consists of performing a mass balance calculation using default carbon content values for feedstock (from the U.S. DOE). Using default carbon content for fuel would not provide the same level of accuracy as using facility-specific carbon contents. This approach is consistent with IPCC Tier 2, DOE 1605(b) and TCR's ‘‘B’’ rated estimation methods.

Option 3. The third option is based on the IPCC Tier 3 method for determining CO_2 emissions from ammonia manufacture. This method calculates emissions based on the monthly measurements of the total feedstock consumed (quantity of natural gas or other feedstock) and the monthly carbon content of the feedstock. All carbon in the feedstock is assumed to be oxidized to CO_2. The accuracy and certainty of this approach is directly related to the accuracy of the feedstock usage and the carbon content of the feedstock. If the measurements or readings are made and verified according to established QA/QC methods, the resulting emission calculations are as accurate as possible. For CO_2 collected and used onsite or transferred offsite, you must follow the methodology provided in proposed 40 CFR part 98, subpart PP of this part (Suppliers of CO_2). This approach is also consistent with DOE's 1605(b) ‘‘A’’ rated method and TCR's ‘‘A2’’ rated estimation methods.

Option 4. The fourth option is using CEMS to directly measure CO_2 emissions. While this method does tend to provide the most accurate emissions measurements, it is likely the costliest of all the monitoring methods.

Proposed Option. Under the proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C and the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS does not measure CO_2 process emissions, the proposed monitoring method is Option 3. You would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2, CH_4 and N_2O emissions from stationary combustion.

The proposed monitoring method is Option 3. Options 3 and 4 provide the most accurate estimates from site-specific conditions. Option 3 is consistent with current feedstock monitoring practices at facilities within this industry, thereby minimizing costs. For CO_2 collected and used onsite or transferred offsite, you must follow the methodology provided in proposed 40 CFR part 98, subpart PP (Suppliers of CO_2).

In general, we decided against existing methodologies that relied on default emission factors or default values for carbon content of materials because the differences among facilities could not be discerned, and such default approaches are inherently inaccurate for site-specific determinations. 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.

The various approaches to monitoring GHG emissions are elaborated in the Ammonia Manufacturing TSD (EPA–HQ–OAR–2008–0508–007).

4. Selection of Procedures for Estimating Missing Data

The proposed rule requires the use of substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable, or ‘‘missing.’’ For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure. There are no missing data procedures for carbon content. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

5. Selection of Data Reporting Requirements

We propose that facilities that estimate their process CO_2 emissions under proposed 40 CFR part 98, subpart G, submit their process CO_2 emissions data and the following additional data on an annual basis. These data are the basis for calculations and are needed for us to understand the emissions data and verify the reasonableness of the reported emissions. We propose facilities submit the following data on an annual basis for each process unit: The total quantity of feedstock consumed for ammonia manufacturing, the monthly analyses of carbon content for each feedstock used in ammonia manufacturing. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and G.

6. Selection of Records That Must Be Retained

We propose that each ammonia manufacturing facility maintain records of monthly carbon content analyses, and the method used to determine the quantity of feedstock used. These records consist of values that are directly used to calculate the emissions that are reported and are necessary to enable verification that the GHG emissions monitoring and calculations were done correctly.

H. Cement Production

1. Definition of the Source Category

Hydraulic Portland cement, the primary product of the cement industry, is a fine gray or white powder produced by heating a mixture of limestone, clay, and other ingredients at high temperature. Limestone is the single largest ingredient required in the cement-making process, and most cement plants are located near large limestone deposits. CO_2 from the chemical process of cement production is the second largest source of industrial CO_2 emissions in the U.S.

During the cement production process, calcium carbonate ($CaCO_3$) (usually from limestone and chalk) is combined with silica-containing materials (such as sand and shale) and is heated in a cement kiln at a temperature of about 1,450 °C (2,400 °F). The $CaCO_3$ forms calcium oxide (or CaO) and CO_2 in a process known as calcination or calcining. Very small amounts of carbonates other than $CaCO_3$, such as magnesium carbonates and non-carbonate organic carbon may also be present in the raw materials, both of which contribute to generation of additional CO_2. The product from the cement kiln is clinker, an intermediate product, and the CO_2 generated as a by-product. The CO_2 is released to the atmosphere.

Additional CO_2 emissions are generated with the formation of partially calcinated cement kiln dust. During clinker production, some of the clinker precursor materials (instead of forming clinker) are entrained in the flue gases exiting the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust[67]. Cement Kiln Dust is collected from the flue gas in dust collection equipment and can either be recycled back to the kiln or be sent offsite for disposal, depending on its quality. Organic carbon in raw materials is also emitted as CO_2 as raw material is heated.

National GHG emissions from cement production were estimated to be 86.83 million metric tons CO_2e in 2006. These emissions include both process-related emissions (CO_2) and on-site stationary combustion emissions (CO_2, CH_4, and N_2O) from 107 cement production facilities. Process-related emissions account for over half of emissions (45.7 million metric tons CO_2), while on-site stationary combustion emissions account for the remaining 41.1 million metric tons CO_2e emissions.

For additional background information on cement production, please refer to the Cement Production TSD (EPA–HQ–OAR–2008–0508–008).

2. Selection of Reporting Threshold

In developing the threshold for cement manufacturing, we considered emissions-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. Table H–1 of this preamble illustrates the emissions and facilities that would be covered under these thresholds.

TABLE H–1. THRESHOLD ANALYSIS FOR CEMENT MANUFACTURING

Threshold level metric tons CO_2e/yr	Total national emissions ($MMTCO_2e$)	Total number of facilities	Emissions Covered		Facilities Covered	
			Million metric tons CO_2e/yr	Percent	Number	Percent
1,000	86.83	107	86.83	100	107	100
10,000	86.83	107	86.83	100	107	100
25,000	86.83	107	86.83	100	107	100
100,000	86.83	107	86.74	99.9	106	99.9

All emissions thresholds examined covered over 99.9 percent of CO_2e emissions from cement facilities. Only one plant out of 107 in the dataset would be excluded by a 100,000 metric tons CO_2e threshold. All facilities would be included under a 25,000 metric tons CO_2e threshold. Therefore, EPA is proposing that all cement production facilities are required to report. Having no threshold covers all of the cement production process emissions without increasing the number of facilities that must report and simplifies the rule.

For a full discussion of the threshold analysis, please refer to the Cement Production TSD (EPA–HQ–OAR–2008–0508–008). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from cement manufacturing (e.g., the 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), CARB mandatory GHG emissions reporting program, EPA's Climate Leaders, the EU Emissions Trading System, and the Cement Sustainability Initiative Protocol). These

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[67] Cement Production TSD (EPA–HQ–OAR–2008–0508–008).

methodologies coalesce around four different options.

Option 1. Apply a default emission factor to the total quantity of clinker produced at the facility. The quantity of clinker produced could be directly measured, or a clinker fraction could be applied to the total quantity of cement produced.

Option 2. Apply site-specific emission factors to the quantity of clinker produced.

Option 3. Measure the carbonate inputs to the furnace. Under this ''kiln input'' approach, emissions are calculated by weighing the mass of individual carbonate species sent to the kiln, multiplying by the emissions factor (relating CO_2 emissions to carbonate content in the kiln feed), and subtracting for uncalcined cement kiln dust.

Option 4. Direct measurement of emissions using CEMS.

Proposed Option. Based on the agency's review of the above approaches, we propose two different methods for quantifying GHG emissions from cement manufacturing, depending on current emissions monitoring at the facility.

CEMS Method. Under the proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate all CO_2 emissions from the industrial source. Also, refer to proposed 40 CFR part 98, subpart C (discussed in Section V.C of this preamble) to estimate combustion-related CH_4 and N_2O.

Calculation Method (Option 2). For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, we propose that these facilities calculate emissions following Option 2 outlined below. You would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. The cement production section provides only those procedures for calculating and reporting process-related emissions.

Under Option 2, we propose that facilities develop facility-specific emission factors relating CO_2 emissions to clinker production for each individual kiln. The emission factor relating CO_2 emissions to clinker production would be based on the percent of measured carbonate content in the clinker (measured on a monthly basis) and the fraction of calcination achieved. The clinker emission factor is then multiplied by the monthly clinker production to estimate monthly process-related CO_2 emissions from cement production. Annual emissions are calculated by summing CO_2 emissions over 12 months across all kilns at the facility.

Most current protocols propose this method, but allow facilities to apply a national default emission factor. We propose the development of a facility-specific emission factor based on the understanding that facilities analyze the carbonate contents of their raw materials to the kiln on a frequent basis, either on a daily basis or every time there is a change in the raw material mix.

Cement Kiln Dust. The CO_2 emissions attributable to calcined material in the cement kiln dust not recycled back to the kiln must be added to the estimate of CO_2 emissions from clinker production. To establish a cement kiln dust adjustment factor, we propose that facilities conduct a chemical analysis on a quarterly basis to estimate the plant-specific fraction of uncalcined carbonate in the cement kiln dust from each kiln, that is not recycled to the kiln each quarter. Again, this method provides reasonable accuracy and is highly consistent with the prevailing methods presented in existing protocols.

TOC Content in Raw Materials. The CO_2 emissions attributable to the TOC content in raw material must be added to the estimate of CO_2 emissions from clinker production and cement kiln dust. We propose that facilities conduct an annual chemical analysis to determine the organic content of the raw material on an annual basis. The emissions are calculated from the TOC content by multiplying the organic content by the amount of raw material consumed annually.

Other Options Considered. We considered three alternative options to estimate process-related emissions from cement production. The first method considered was to apply default emission factors to clinker production (either based on measurement of clinker, or by applying a clinker fraction to cement production). Applying default emission factors to clinker production is one of the most common approaches in existing protocols. However, 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.

In some protocols, this method requires correcting for purchases and sales of clinker, such that a facility is only accounting for emissions from the clinker that is manufactured on site. This approach provides better emissions data than protocols where the method does not correct for clinker purchases and sales. In some protocols, the method requires reporters to start with cement production, estimate the clinker fraction, and then estimate the carbonate input used to produce the clinker. Conceptually, this might not be any different than the kiln input approach as the facility would ultimately have to identify and quantify the carbonate inputs to the kiln.

The kiln input approach was considered, but not proposed, because it would not lead to significantly reduced uncertainty in the emissions estimate over the clinker based approach, where a site-specific emission factor is developed using periodic sampling of the carbonate mix into the kiln. The primary difference is the proposed clinker-based approach requires a monthly analysis of the degree of calcination achieved in the clinker in order to develop the facility-specific emissions factor, whereas the kiln input approach would require monthly monitoring of the inputs and outputs of the kiln. We concluded that although the kiln input does not improve certainty estimates significantly, it could potentially be more costly depending on the carbonate input sampling frequency.

Early domestic and international guidance documents for estimating process CO_2 emissions from cement production offered the option of applying a default emission factor to cement production (e.g. IPCC Tier 1, DOE 1605(b) ''C'' rated approach). This is no longer considered an acceptable method in national inventories therefore we did not consider it further for developing a mandatory GHG reporting rule.

The various approaches to monitoring GHG emissions are elaborated in the Cement Production TSD (EPA–HQ–OAR–2008–0508–008).

4. Selection of Procedures for Estimating Missing Data

For facilities with CEMs, we propose that facilities follow the missing data procedures in proposed 40 CFR part 98, subpart C, which are also discussed in Section V.C of this preamble.

For facilities without CEMs, we propose that no missing data procedures would apply because the emission factors used to estimate CO_2 emissions from clinker and cement kiln dust production are derived from routine tests of carbonate contents. In the event data on carbonate content analysis is missing we propose that the facility undertake a new analysis of carbonate contents. We are not proposing any missing data allowance for clinker and cement kiln dust production data. The likelihood for missing input, clinker and cement kiln dust production data is low, as businesses closely track their purchase of production inputs, quantity of clinker produced, and quantity of cement kiln dust discarded.

5. Selection of Data Reporting Requirements

We propose that facilities submit annual CO_2 emissions from cement production, as well as any stationary fuel combustion emissions. In addition, facilities using CEMS would be required to follow the data reporting requirements in proposed 40 CFR part 98, subpart C. Facilities using the clinker-based approach would be required to report annual clinker production, annual cement kiln dust production, number of kilns, site-specific clinker emission factor, the total annual fraction of cement kiln dust recycled to the kiln, and the quantity of CO_2 captured for use and the end use, if known. In addition, we propose that facilities submit their annual analysis of carbonate composition, the total annual fraction of calcination achieved (for each carbonate), organic carbon content of the raw material, and the amount of raw material consumed annually. These data, used as the basis of the calculations, are needed for EPA to understand the emissions data and verify reasonableness of the reported emissions. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and H.

6. Selection of Records That Must Be Retained

In addition to the data reported, we propose that facilities using the clinker-based approach to calculate emissions keep records of monthly carbonate consumption, monthly cement production, monthly clinker production, results from monthly chemical analysis of carbonates, documentation of calculated site specific clinker emission factor, quarterly cement kiln dust production, total annual fraction calcination achieved, organic carbon content of the raw material, and the amount of raw material consumed annually. These records include values directly used to calculate the reported emissions; and these records are necessary to verify the estimated GHG emissions. A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and H.

I. Electronics Manufacturing

1. Definition of the Source Category

The electronics industry uses multiple long-lived fluorinated GHGs such as PFCs, HFCs, SF_6, and NF_3 during manufacturing of semiconductors, liquid crystal displays (LCDs), microelectrical mechanical systems (MEMs), and photovoltaic cells (PV). We are also seeking comment below on the inclusion of light-emitting diodes (LEDs), disk readers and other products as part of the electronics manufacturing source category.

The fluorinated gases (at room temperature) are used for plasma etching of silicon materials and cleaning deposition tool chambers. Additionally, semiconductor manufacturing employs fluorinated GHGs (typically liquids at room temperature) as heat transfer fluids. The most common fluorinated GHGs in use are HFC–23, CF_4, C_2F_6, NF_3 and SF_6, although other compounds such as perfluoropropane (C_3F_8) and perfluorocyclobutane (c-C_4F_8) are also used (EPA, 2008a).

Electronics manufacturers may also use N_2O as the oxygen source for chemical vapor deposition of silicon oxynitride or silicon dioxide. Besides dielectric film etching and chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and refractory metal films like tungsten. Table I–1 of this preamble presents the fluorinated GHGs typically used during manufacture of each of these electronics devices.

TABLE I–1. FLUORINATED GHGS USED BY THE ELECTRONICS INDUSTRY

Product type	Fluorinated GHGs used during manufacture
Electronics (e.g., Semiconductor, MEMS, LCD, PV) ..	CF_4, C_2F_6, C_3F_8, c–C_4F_8, c–C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6, and Heat Transfer Fluids (CF_3–(O–CF(CF3)–CF2)n–(O–CF2)m–O–CF3, CnF2n+2, CnF2n+1(O) CmF2m+1, CnF2nO, (CnF2n+1)3N)[a].

[a] IPCC Guidelines do not specify the fluorinated GHGs used by the MEMs industry. Literature reviews revealed that CF_4, SF_6, and the Bosch process (consisting of alternating steps of SF_6 and c–C_4F_8) are used to manufacture MEMs. For further information, see the Electronics Manufacturing TSD (EPA–HQ–OAR–2008–0508–009).

The etching process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission control systems are employed, into the atmosphere.

Chambers used for depositing dielectric films are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless emission control systems are employed, into the atmosphere.

In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated GHGs which are then exhausted, unless abated, into the atmosphere. For example, when C_2F_6 is used in cleaning or etching, CF_4 is generated and emitted as a process by-product.

Fluorinated GHG liquids (at room temperature) such as fully fluorinated linear, branched or cyclic alkanes, ethers, tertiary amines and aminoethers, and mixtures thereof are used as heat transfer fluids at several semiconductor facilities to cool process equipment, control temperature during device testing, and solder semiconductor devices to circuit boards. The fluorinated heat transfer fluid's high vapor pressures can lead to evaporative losses during use.[68] We are seeking comment on the extent of use and

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[68] Electronics Manufacturing TSD (EPA–HQ–OAR–2008–0508–009); 2006 IPCC Guidelines.

annual replacement quantities of fluorinated liquids as heat transfer fluids in other electronics sectors, such as their use for cooling or cleaning during LCD manufacture.

Total U.S. Emissions. Emissions of fluorinated GHGs from an estimated 216 electronics facilities were estimated to be 6.1 million metric tons CO_2e in 2006. Below is a breakdown of emissions by electronics product type.

Semiconductors. Emissions of fluorinated GHGs, including heat transfer fluids, from 175 semiconductor facilities were estimated to be 5.9 million metric tons CO_2e in 2006. Of the total estimated semiconductor emissions, 5.4 million metric tons CO_2e are from etching/chamber cleaning and 0.5 million metric tons CO_2e are from heat transfer fluid usage. Partners of the *PFC Reduction/Climate Partnership for Semiconductors* comprise approximately 80 percent of U.S. semiconductor production capacity. These partners have committed to reduce their emissions (exclusive of heat transfer fluid emissions) to 10 percent below their 1995 levels by 2010, and their emissions have been on a general decline toward attainment of this goal since 1999.

MEMs. Emissions of fluorinated GHGs from 12 facilities were estimated to be 0.03 million metric tons CO_2e in 2006.

LCDs. Emissions of fluorinated GHGs from 9 facilities were estimated to be 0.02 million metric tons CO_2e in 2006.

PVs. Emissions of fluorinated GHGs from 20 PV facilities were estimated to be 0.07 million metric tons CO_2e in 2006. We request comment on the number and capacity of thin film (i.e., amorphous silicon) and other PV manufacturing facilities in the U.S. using fluorinated GHGs.

Emissions To Be Reported. This section details our proposed requirements for reporting fluorinated GHG and N_2O emissions from the following processes and activities:

(1) Plasma etching;
(2) Chamber cleaning;
(3) Chemical vapor deposition using N_2O as the oxygen source; and
(4) Heat transfer fluid use.

Our understanding is that only semiconductor facilities use heat transfer fluids; we request comment on this assumption.

For additional background information on the electronics industry, refer to the Electronics Manufacturing TSD (EPA–HQ–OAR–2008–0508–009).

2. Selection of Reporting Threshold

For manufacture of semiconductors, LCDs, and MEMs, we are proposing capacity-based thresholds equivalent to an annual emissions threshold of 25,000 metric tons CO_2e. For manufacture of PVs for which we have less information on use and emissions of fluorinated GHGs, we are proposing an emissions threshold of 25,000 metric tons of CO_2e.

We are seeking comment on the inclusion of LEDs, disk readers and other products in the electronics manufacturing source category. Given that the manufacturing process for these devices is similar to other electronics, we are specifically interested in seeking feedback on the level of emissions from their manufacturer and whether subjecting these products to an emissions threshold of 25,000 metric ton CO_2e would be appropriate.

In our analysis, we considered emission 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 per year. Table I–2 of this preamble shows emissions and facilities that would be captured by the respective emissions thresholds.

TABLE I–2. THRESHOLD ANALYSIS FOR ELECTRONICS INDUSTRY

Emission threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
1,000	5,984,462	216	5,972,909	99.8	173	80
10,000	5,984,462	216	5,840,411	98	118	55
25,000	5,984,462	216	5,708,283	95	96	44
100,000	5,984,462	216	4,708,283	79	54	25

We selected the 25,000 metric tons CO_2e per year threshold because this threshold maximizes emissions reporting, while excluding small facilities that do not contribute significantly to the overall GHG emissions.

We propose to use a production-based threshold based on the rated capacities of facilities, as opposed to an emissions-based threshold, where possible, because it simplifies the applicability determination. Therefore, we derived production capacity thresholds that are approximately equivalent to metric tons CO_2e using IPCC Tier 1 default emissions factors and assuming 100 percent capacity utilization. Where IPCC Tier 1 default factors were unavailable (i.e., MEMs), the emissions factor was estimated based on those of semiconductors for the relevant fluorinated GHGs. The proposed capacity-based thresholds are 1,000 m^2 silicon for semiconductors; 4,000 m^2 silicon for MEMs; and 236,000 m2 LCD for LCDs. Table I–3 of this preamble shows the estimated emissions and number of facilities that would report for each source under the proposed capacity-based thresholds. PV is not shown in the table because we are proposing an emissions threshold due to lack of information.

TABLE I–3. SUMMARY OF RULE APPLICABILITY UNDER THE PROPOSED CAPACITY-BASED THRESHOLDS

Emissions source	Capacity-based threshold	Total national facilities	Total emissions of source (metric tons CO_2e)	Emissions covered		Facilities covered	
				Metric tons CO_2e/yr	Percent	Facilities	Percent
Semi-conductors	1,080 silicon m^2	175	5,741,676	5,492,066	96	91	52
MEMs	1,020 silicon m^2	12	146,115	96,164	66	2	17
LCD	235,700 LCD m^2	9	23,632	0	0	0	0

The proposed capacity-based thresholds are estimated to cover about 50 percent of semiconductor facilities and between 0 percent and 20 percent of the facilities manufacturing MEMs and LCDs. At the same time, the thresholds are expected to cover nearly 96 percent of fluorinated GHG emissions from semiconductor facilities, and 0 percent and 66 percent of fluorinated GHG emissions from facilities manufacturing LCDs and MEMs, respectively. Combined these emissions are estimated to account for close to 94 percent of fluorinated GHG emissions from electronics as a whole.

We are proposing capacity-based thresholds for the electronics industry, where possible, because electronics manufacturers may employ emissions control equipment (e.g., thermal oxidizers, fluorinated GHG capture recycle systems) to lower their fluorinated GHG emissions. In addition, capacity-based thresholds would permit facilities to quickly determine whether or not they must report under this rule.

When abatement equipment is used, electronics manufacturers often estimate their emissions using the manufacturer-published DRE for the equipment. However, abatement equipment may fail to achieve its rated DRE either because it is not being properly operated and maintained or because the DRE itself was incorrectly measured due to a failure to account for the effects of dilution. (For example, CF_4 can be off by as much as a factor of 20 to 50 and C_2F_6 can be off by a factor of up to 10 because of failure to properly account for dilution.) In either event, the actual emissions from facilities employing abatement equipment may exceed estimates based on the rated DREs of this equipment and may therefore exceed the 25,000 metric tons CO_2e threshold without the knowledge of the facility operators. Measuring and reporting emission control device performance is therefore important for developing an accurate estimate of emissions. As discussed below, we propose an emission estimation method that would account for destruction by abatement equipment only if facilities verified the performance of their abatement equipment using one of two methods. If facilities choose not to verify the performance of their abatement equipment, the estimation method would not account for any destruction by the abatement device.

For additional background information on the threshold analysis, refer to the Electronics Manufacturing TSD (EPA–HQ–OAR–2008–0508–009). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

a. Etching and Cleaning Emissions

Fluorinated GHG Emissions. Under the proposed rule, large semiconductor facilities (defined as facilities with annual capacities of greater than 10,500 m^2 silicon) would be required to estimate their fluorinated GHG emissions from etching and cleaning using an approach based on the IPCC Tier 3 method, and all other facilities would be required to use an approach based on the IPCC Tier 2b method. We have determined that large semiconductor facilities are already using Tier 3 methods and/or have the necessary data readily available either in-house or from suppliers to apply the highest tier method. The difference between the proposed approaches and the IPCC methods is that the proposed approaches include stricter requirements for quantifying the gas destroyed by abatement equipment, as described below. None of the IPCC methods require a standard protocol to estimate DREs of abatement equipment. Given that the actual DRE of the abatement equipment can be significantly smaller (by up to a factor of 50) compared to the manufacturer rated DRE, we are proposing verification of the DREs using a standard reporting protocol (Burton, 2007).

Under the proposed rule, we estimate that 17 percent of all semiconductor manufacturing facilities would be required to report using an IPCC Tier 3 approach (equivalent to 29 facilities out of 175 total facilities) and that 56 percent of total semiconductor emissions (equivalent 3.4 million metric tons CO_2e out of a total 5.9 million metric tons CO_2e emissions) would be reported using the IPCC Tier 3 approach.

Method for Large Facilities. The IPCC Tier 3 approach uses company-specific data on (1) gas consumption, (2) gas utilization, (3) by-product formation, and (4) DRE for all emission abatement processes at the facility.

Information on gas consumption by process is often gathered as business as usual,[69] and information on gas utilization, by-product formation, and DRE for each process is readily available from tool manufacturers and can also be experimentally measured on-site at the facility. We propose that the DRE for abatement equipment be experimentally measured using the protocol described below.

The guidance prepared by International SEMATECH Technology Transfer #0612485A–ENG (December 2006) must be followed when preparing gas utilization and by-product formation measurements. We have determined that electronics manufacturers commonly track fluorinated GHG consumption using flow metering systems calibrated to ±1 percent or better accuracy. Thus the equation for estimating emissions does not account for cylinder heels. However, a facility may choose to estimate consumption by weighing fluorinated GHG cylinders when placed into and taken out of service, as is common practice by the magnesium industry.

The use of the IPCC Tier 3 method and standard site-specific DRE measurement would provide the most certain and practical emission estimates for large facilities. The uncertainty associated with an IPCC Tier 3 approach is lower than any of the other IPCC approaches, and is on the order of ±30 percent at the 95 percent confidence interval. We estimate that the Tier 3 approach would not impose a significant burden on facilities because large semiconductor facilities are already using Tier 3 methods and/or have the necessary data to do so readily available, as noted above.

Method for Other Semiconductor, LCD, MEMS, and PV Facilities. The IPCC Tier 2b approach is based on gas consumption by process type (i.e., etch or chamber clean) multiplied by default factors for utilization, by-product formation, and destruction. We are proposing that site-specific DRE measurements be used for quantifying the amount of gas destroyed. The DRE measurements would be determined using the protocol described below.

The Tier 2b approach does not account for variation among individual processes or tools and, therefore, the estimated emissions have an uncertainty about twice as high as that of IPCC Tier 3 estimates. However, we have concluded that the IPCC Tier 3 method would be unduly burdensome to the estimated 146 facilities with annual production less than 10,500 m^2 silicon. We estimate that the IPCC Tier 2b approach would not impose a significant burden on facilities because it requires only minimal fluorinated gas usage tracking by major production process type. These production input

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[69] In the RIA for this rulemaking, we have conservatively included the costs of gathering, consolidating, and checking process-specific gas consumption information. However, we believe that this information is already gathered in many cases for purposes of internal process control and/or emissions reporting under EPA's voluntary PFC Reduction Program for the Semiconductor Industry.

data are readily available at all U.S. manufacturing facilities.

N_2O Emissions. We are proposing that electronics manufacturers use a simple mass-balance approach to estimate emissions of N_2O during etching and chamber cleaning. This methodology assumes N_2O is not converted or destroyed during etching or chamber cleaning, due to lack of N_2O utilization data. We request comment on utilization factors for N_2O during etching and chamber cleaning, and any data on N_2O by-product formation.

Verification of DRE. For facilities that employ abatement devices and wish to reflect the emission reductions due to these devices in their emissions estimates, two methods are proposed for verifying the DRE of the equipment. Either method may be followed.

The first method would require facilities (or their equipment suppliers) to test the DRE of the equipment using an industry standard protocol, such as the one under development by EPA as part of the *PFC Reduction/Climate Partnership for Semiconductors* (not yet published). This draft protocol requires facilities to experimentally determine the effective dilution through the abatement device and to measure abatement DRE during actual or simulated process conditions. The second method would require facilities to buy equipment that has been tested by an independent third party (e.g., UL) using an industry standard protocol such as the one under development by EPA. Under this approach, manufacturers would pay the third party to select random samples of each model and test them. Because testing would not need to be obtained for every piece of equipment sold, this approach would probably be less expensive than in-house testing by electronics manufacturers, but it may not capture the full range of conditions under which the abatement equipment would actually be used.

We believe that the proposed DRE measurement method is generally robust, but we are requesting comment on one aspect of that method. We are concerned that the DREs measured and calculated for CF_4 may vary depending on the mix of input gases used in the electronics manufacturing process. The calculated DRE for CF_4 may be influenced by the formation of CF_4 from other PFCs during the destruction process itself, and different input gases have different CF_4 byproduct formation rates. This means that a DRE for CF_4 calculated using one set of input gases might over- or under-estimate CF_4 emissions when applied to another set of input gases (or even the original set in different proportions). We request comment on the likelihood and potential severity of such errors and on how they might be avoided.

Facilities pursuing either DRE verification method would also be required to use the equipment within the manufacturer's specified equipment lifetime, operate the equipment within manufacturer specified limits for the gas mix and exhaust flow rate intended for fluorinated GHG destruction, and maintain the equipment according to the manufacturer's guidelines. We request comment on these proposed requirements.

b. Emissions of Heat Transfer Fluids

We propose that electronics manufacturers use the IPCC Tier 2 approach, which is a mass-balance approach, to estimate the emissions of each fluorinated heat transfer fluid. The IPCC Tier 2 approach uses company-specific data and accounts for differences among facilities' heat transfer fluids (which vary in their GWPs), leak rates, and service practices. It has an uncertainty on the order of ±20 percent at the 95 percent confidence interval according to the 2006 IPCC Guidelines. The Tier 2 approach is preferable to the IPCC Tier 1 approach, which relies on a default emissions factor to estimate heat transfer fluid emissions and has relatively high uncertainty compared to the Tier 2 approach.

c. Review of Existing Reporting Programs and Methodologies

We reviewed the PFC Reduction/Climate Partnership for the Semiconductor Industry, U.S. GHG Inventory, 1605(b), EPA Climate Leaders, WRI, TRI, and the World Semiconductor Council methods for estimating etching and cleaning emissions. All of the methods draw from both the 2000 and 2006 IPCC Guidelines.

Etching and Cleaning. For etching and cleaning emissions, we considered the 2006 IPCC Tier 1 and Tier 2a methods, as well as a Tier 2b/3 hybrid which would apply Tier 3 to the most heavily used fluorinated GHGs in all facilities.

The Tier 1 approach is based on the surface area of substrate (e.g., silicon, LCD or PV-cell) produced during manufacture multiplied by a default gas-specific emission factor. The advantages of the Tier 1 approach lie in its simplicity. However, this method does not account for the differences among process types (i.e., etching versus cleaning), individual processes, or tools, leading to uncertainties in the default emission factors of up to 200 percent at the 95 percent confidence interval.[70] Facilities routinely monitor gas consumption as part of business as usual, making it technically feasible to employ a method of at least IPCC Tier 2a complexity or higher without additional data collection efforts.

The Tier 2a approach is based on the gas consumption multiplied by default factors for utilization, by-product formation, and destruction. The Tier 2a approach is relatively simple, given that gas consumption data is collected as part of business as usual. However, due to variation in gas utilization between etching and cleaning processes, the estimated emissions using Tier 2a have greater uncertainty than Tier 2b estimated emissions.

Tier 2b/3 hybrid approach involves requiring Tier 3 reporting for all facilities, but only for the top three gases emitted at each facility. For all other gases, the Tier 2b approach would be required. The top three gases emitted, based on data in the Inventory of U.S. GHG Emissions and Sinks, are C_2F_6, CF_4, and SF_6 (EPA, 2008a). These top three gases accounted for approximately 80 percent of total fluorinated GHG emissions from semiconductor manufacturing during etching and chamber cleaning in 2006. The uncertainty associated with the Tier 2b/3 hybrid approach has not been determined, but is estimated to be between the uncertainty for a Tier 2b and Tier 3 approach.

We did not select the Tier 1 and Tier 2a methods due to the greater uncertainty inherent in these approaches. Although the Tier 2b/3 hybrid approach would provide more accurate emissions estimates for small facilities, we concluded that the Tier 2b method with site-specific DRE measurements would provide sufficient accuracy without the additional monitoring and recordkeeping requirements of the Tier 3 method.

We propose collecting emissions data from MEMS manufacturers meeting the threshold criterion although no IPCC default emission factors exist for MEMs and the IPCC emission factors for semiconductor and LCD manufacturing may not be reliable for MEMs. Therefore, we are seeking information on emissions and emission factors for both MEMs and LCD manufacturing.

Heat Transfer Fluids. For heat transfer fluid emissions, we reviewed both the IPCC Tier 1 and IPCC Tier 2 approaches. The Tier 1 approach for heat transfer fluid emissions is based on the

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[70] This uncertainty refers only to semiconductors and LCDs. Tier 1 emission factor uncertainty for PV was not estimated in the 2006 IPCC Guidelines.

utilization capacity of the semiconductor facility multiplied by a default emission factor. Although the Tier 1 approach has the advantages of simplicity, it is less accurate than the Tier 2 approach according to the 2006 IPCC Guidelines.

4. Selection of Procedures for Estimating Missing Data

Where facility-specific process gas utilization rates and by-product gas formation rates are missing, facilities can estimate etching/cleaning emissions by applying defaults from the next lower Tier (e.g., IPCC Tier 2b or Tier 2a) to estimate missing data. However, facilities must limit their use of defaults from the next lower Tier to less than 5 percent of their emissions estimate.

Default values for estimating DRE would not be permitted. DRE values must be estimated as zero in the absence of facility-specific DREs that have been measured using a standard protocol. Gas consumption is collected as business as usual and is not expected to be missing; therefore, it would not be permitted to revert to the Tier 1 approach for estimating emissions. When estimating heat transfer fluid emissions during semiconductor manufacture, the use of the mass-balance approach requires correct records for all inputs. Should the facility be missing records for a given input, it may be possible that the heat transfer fluid supplier has information in their records for the facility.

5. Selection of Data Reporting Requirements

Owners and operators would be required to report GHG emissions for the facility, for all plasma etching processes, all chamber cleaning, all chemical vapor deposition processes, and all heat tranfer fluid use. Along with their emissions, facilities would be required to report the following: Method used (i.e., 2b or 3), mass of each gas fed into each process type, production capacity in terms of substrate surface area (e.g., silicon, PV-cell, LCD), factors used for gas utilization, by-product formation and their sources/uncertainties, emission control technology DREs and their uncertainties, fraction of gas fed into each process type with emissions, control technologies, description of abatement controls, inputs in the mass-balance equation (for heat transfer fluid emissions), example calculation, and emissions uncertainty estimate.

These data form the basis of the calculations and are needed for us to understand the emissions data and verify the reasonableness of the reported emissions.

6. Selection of Records That Must Be Retained

We propose that facilities keep records of the following: Data actually used to estimate emissions, records supporting values used to estimate emissions, the initial and any subsequent tests of the DRE of oxidizers, the initial and any subsequent tests to determine emission factors for process, and abatement device calibration/maintenance records.

These records consist of values that are directly used to calculate the emissions that are reported and are necessary to enable verification that the GHG emissions monitoring and calculations are done correctly.

J. Ethanol Production

1. Definition of the Source Category

Ethanol is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar, starch, grain, and cellulosic biomass feedstocks, or produced synthetically from ethylene or hydrogen and carbon monoxide.

The sources of GHG emissions at ethanol production facilities that must be reported under the proposed rule are stationary fuel combustion, onsite landfills, and onsite wastewater treatment.

Proposed requirements for stationary fuel combustion emissions are set forth in proposed 40 CFR part 98, subpart C.

Proposed requirements for landfill emissions are set forth in Section V.HH of this preamble. Data is unavailable on landfilling at ethanol facilities, but it is our understanding that some of these facilities may have landfills with significant CH_4 emissions. For more information on landfills at industrial facilities, please refer to the Ethanol Production TSD (EPA–HQ–OAR–2008–0508–010). EPA is seeking comment on available data sources for landfilling practices at ethanol production facilities.

The wastewater generated at ethanol production facilities is handled in a variety of ways, with dry milling and wet milling facilities generally treating wastewaters differently. In 2006, CH_4 emissions from wastewater treatment at ethanol production facilities were 68,200 metric tons CO_2e. Proposed requirements for GHG emissions form wastewater treatment are set forth in Section V.II of this preamble. For more information on wastewater treatment at ethanol production facilities, please refer to the Ethanol Production TSD (EPA–HQ–OAR–2008–0508–010).

As noted in Section IV.B of this preamble under the heading ‘‘Reporting by fuel and industrial gas suppliers’’, ethanol producers and other suppliers of biomass-based fuel are not required to report GHG emissions from their products under this proposal, and we seek comment on this approach.

2. Selection of Reporting Threshold

The proposed threshold for reporting emissions from ethanol production facilities is 25,000 metric tons CO_2e total emissions from stationary fuel combustion, landfills, and onsite wastewater treatment. Table J–1 of this preamble illustrates the emissions and facilities that would be covered under various thresholds.

TABLE J–1. THRESHOLD ANALYSIS FOR ETHANOL PRODUCTION

Threshold level	National emissions mtCO_2e	Total number of facilities	Emissions covered		Facilities covered	
			mtCO_2e/year	Percent	Number	Percent
1,000 mtCO_2e	Not estimated	140	Not estimated	Not estimated	>101	>72
10,000 mtCO_2e	Not estimated	140	Not estimated	Not estimated	>94	>67
25,000 mtCO_2e	Not estimated	140	Not estimated	Not estimated	>86	>61
100,000 mtCO_2e	Not estimated	140	Not estimated	Not estimated	>43	>31

Data were unavailable to estimate emissions from landfills at ethanol refineries, or to estimate the combined wastewater treatment and stationary fuel combustion emissions at facilities. Data on stationary fuel combustion were used to estimate the minimum number of facilities that would meet each of the facility-level thresholds examined. The

25,000 metric tons CO_2e threshold results in a reasonable number of reporters, and is consistent with thresholds for other source categories.

For more information on this analysis, please refer to the Ethanol Production TSD (EPA–HQ–OAR–2008–0508–010). EPA is seeking comment on the analysis and on alternative data sources for stationary combustion at ethanol production facilities. For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Refer to Sections V.C, V.HH, and V.II of this preamble for monitoring methods for general stationary fuel combustion sources, landfills, and wastewater treatment occurring on-site at ethanol production facilities.

4. Selection of Procedures for Estimating Missing Data

Refer to Sections V.C, V.HH, and V.II of this preamble for procedures for estimating missing data for general stationary fuel combustion sources, landfills, and industrial wastewater treatment occurring on-site at ethanol production facilities.

5. Selection of Data Reporting Requirements

Refer to Sections V.C, V.HH, and V.II of this preamble for reporting requirements for general stationary fuel combustion sources, landfills, and industrial wastewater treatment occurring on-site at ethanol production facilities. In addition, you would be required to report the quantity of CO_2e captured for use (if applicable) and the end use, if known. For more information on reporting requirements for CO_2e capture, please refer to Section V.PP of this preamble.

6. Selection of Records That Must Be Maintained

Refer to Sections V.C, V.HH, and V.GG of this preamble for recordkeeping requirements for stationary fuel combustion, landfills, and industrial wastewater treatment occurring on-site at ethanol production facilities.

K. Ferroalloy Production

1. Definition of the Source Category

A ferroalloy is an alloy of iron with at least one other metal such as chromium, silicon, molybdenum, manganese, or titanium. For this proposed rule, we are defining the ferroalloy production source category to consist of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal. Ferroalloys are used extensively in the iron and steel industry to impart distinctive qualities to stainless and other specialty steels, and serve important functions during iron and steel production cycles. Silicon metal is included in the ferroalloy metals category due to the similarities between its production process and that of ferrosilicon. Silicon metal is used in alloys of aluminum and in the chemical industry as a raw material in silicon-based chemical manufacturing.

The basic process used at U.S. ferroalloy production facilities is a batch process in which a measured mixture of metals, carbonaceous reducing agents, and slag forming materials are melted and reduced in an electric arc furnace. The carbonaceous reducing agents typically used are coke or coal. Molten alloy tapped from the electric arc furnace is casted into solid alloy slabs which are further mechanically processed for sale as product or disposed in landfills.

Ferroalloy production results in both combustion and process-related GHG emissions. The major source of GHG emissions from a ferroalloy production facility are the process-related emissions from the electric arc furnace operations. These emissions, which consist primarily of CO_2e with smaller amounts of CH_4, result from the reduction of the metallic oxides and the consumption of the graphite (carbon) electrodes during the batch process.

Total nationwide GHG emissions from ferroalloy production facilities operating in the U.S. were estimated to be approximately 2.3 million metric tons CO_2e for the year 2006. Process-related GHG emissions were 2.0 million metric tons CO_2e (86 percent of the total emissions). The remaining 0.3 million metric tons CO_2e (14 percent of the total emissions) were combustion GHG emissions.

Additional background information about GHG emissions from the ferroalloy production source category is available in the Ferroalloy Production TSD (EPA–HQ–OAR–2008–0508–011).

2. Selection of Reporting Threshold

Ferroalloy production facilities in the U.S. vary in the specific types of alloy products produced. In developing the threshold for ferroalloy production facilities, we considered using annual GHG emissions-based threshold levels 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. Table K–1 of this preamble presents the estimated emissions and number of facilities that would be subject to GHG emissions reporting, based upon emission estimates using production capacity data for the nine U.S. facilities that produce either ferrosilicon, silicon metal, ferrochromium, ferromanganese, or silicomanganese alloys. We were unable to obtain production data for an estimated five additional facilities that produce ferromolybdenum and ferrotitanium alloys.

TABLE K–1. THRESHOLD ANALYSIS FOR FERROALLOY PRODUCTION FACILITIES

Threshold level (metric tons CO_2e/yr)	Total national emissions (metric tons CO_2e/yr)	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	2,343,990	9	2,343,990	100	9	100
10,000	2,343,990	9	2,343,990	100	9	100
25,000	2,343,990	9	2,343,990	100	9	100
100,000	2,343,990	9	2,276,639	97	8	89

Table K–1 of this preamble shows that all nine of the facilities would be required to report emissions at all thresholds except 100,000 metric tons CO_2e, when considering combustion and process-related emissions. The rule could be simplified for these facilities by making the rule applicable to all ferroalloy production facilities.

However, because the threshold analysis did not include all of the facilities in the ferroalloy source category that potentially could be subject to the rule, we have decided that it is appropriate to include a reporting threshold level. The proposed threshold selected for reporting emissions from ferroalloy production facilities is 25,000 metric tons CO_2e per year consistent with the threshold level being proposed for other source categories. This threshold level would avoid placing a reporting burden on any small specialty ferroalloy production facility which may operate as a small business while still requiring the reporting of GHG emissions from the ferroalloy production facilities releasing most of the GHG emissions in the source category. A full discussion of the threshold selection analysis is available in the Ferroalloy Production TSD (EPA–HQ–OAR–2008–0508–011). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We reviewed 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. In general, the methodologies used for estimating process related GHG emissions at the facility level coalesce around the following four options.

Option 1. Apply a default emission factor to ferroalloy production. This is a simplified emission calculation method using only default emission factors to estimate process-related CO_2 and CH_4 emissions. The method requires multiplying the amount of each ferroalloy product type produced by the appropriate default emission factors from the 2006 IPCC Guidelines.

Option 2. Perform a monthly carbon balance using measurements of the carbon content of specific process inputs and process outputs and the amounts of these materials consumed or produced during a specified reporting period. This option is applicable to estimating only CO_2 emissions from an electric arc furnace, and is the IPCC Tier 3 approach and the higher order methods in the Canadian and Australian reporting programs. Implementation of this method requires you to determine the carbon contents of carbonaceous material inputs to and outputs from the electric arc furnaces. Facilities determine carbon contents through analysis of representative samples of the material or from information provided by the material suppliers. In addition, the quantities of these materials consumed and produced during production would be measured and recorded. To obtain the CO_2 emissions estimate, the average carbon content of each input and output material is multiplied by the corresponding mass consumed and a conversion of carbon to CO_2. The difference between the calculated total carbon input and the total carbon output is the estimated CO_2 emissions to the atmosphere. This method assumes that all of the carbon is converted during the process. For estimating the CH_4 emissions from the electric arc furnace, selection of this option for estimating CO_2 emissions would still require using the Option 1 approach of applying default emission factors to estimate CH_4 emissions.

Option 3. Use CO_2 emissions data from a stack test performed using U.S. EPA test methods to develop a site-specific process emissions factor which is then applied to quantity measurement data of feed material or product for the specified reporting period. This monitoring method is applicable to electric arc furnace configurations for which the GHG emissions are contained within a stack or vent. Using site-specific emissions factors based on short-term stack testing is appropriate for those facilities where process inputs (e.g., feed materials, carbonaceous reducing agents) and process operating parameters remain relatively consistent over time.

Option 4. Use direct emission testing of CO_2 emissions. For electric arc furnace configurations in which the process off-gases are contained within a stack or vent, direct measurement of the CO_2 emissions can be made by continuously measuring the off-gas stream CO_2 concentration and flow rate using a CEMS. Using a CEMS, the total CO_2 emissions tabulated from the recorded emissions measurement data would be reported annually. If a ferroalloy production facility uses an open or semi-open electric arc furnace for which the CO_2 emissions are not fully captured and contained within a stack or vent (i.e., a significant portion of the CO_2 emissions escape capture by the hood and are release directly to the atmosphere), then another GHG emission estimation method other than direct measurement would be more appropriate.

Proposed Option. Under the proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C, to estimate CO_2 emissions from the industrial source. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where CEMS would not adequately account for process emissions, the proposed monitoring method is Option 2. You would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. This section of the preamble provides procedures only for calculating and reporting process-related emissions.

Given the variability of the alloy products produced and carbonaceous reducing agents used at U.S. ferroalloy production facilities, we concluded that using facility-specific information under Option 2 is preferred for estimating CO_2 emissions from electric arc furnaces. This method is consistent with IPCC Tier 3 methods and the preferred approaches for estimating emissions in the Canadian and Australian mandatory reporting programs. We consider the additional burden of the material measurements required for the carbon balance small in relation to the increased accuracy expected from using this site-specific information to calculate CO_2 emissions.

Emissions data collected under Option 3 would have the lowest uncertainty, expected to be less than 5 percent. For Option 2, the material-specific emission factors would be expected to be within 10 percent, which would provide less uncertainty overall than for Option 1, which may have uncertainty of 25 to 50 percent. The use of the default CO_2 emission factors under Option 1 would be more appropriate for GHG estimates from aggregated process information on a sector-wide or nationwide basis than for determining GHG emissions from specific facilities.

In comparison to the CO_2 emissions levels from an electric arc furnace, the CH_4 emissions compose a small fraction of the total GHG emissions from electric arc furnace operations at a ferroalloy production facility. The proposed Option 2 above doesn't account for CH_4. Considering the amount that CH_4 emissions contribute to the total GHG emissions and the absence of facility-specific methods in other reporting systems, we are proposing that facilities use Option 1 and the IPCC default emission factors to estimate CH_4 emissions from electric arc furnaces at ferroalloy production facilities. This method provides reasonable estimates of the magnitude of the CH_4 emissions from the units without the need for owners or operator to conduct on-site CH_4 emissions measurements.

We also decided against Option 3 because of the potential for significant variations at ferroalloy production facilities in the characteristics and quantities of the electric arc furnace inputs (e.g., metal ores, carbonaceous reducing agents) and process operating parameters. A method using periodic, short-term stack testing would not be practical or appropriate for those ferroalloy production facilities where the electric arc furnace inputs and operating parameters do not remain relatively consistent over the reporting period.

The various approaches to monitoring GHG emissions are elaborated in the Ferroalloy Production TSD (EPA–HQ–OAR–2008–0508–011).

4. Selection of Procedures for Estimating Missing Data

In cases when an owner or operator calculates CO_2 and CH_4 emissions using a carbon balance or an emission factor, the proposed rule would require the use of substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable, or ''missing.'' If the carbon content analysis of carbon inputs or outputs is missing or lost, the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. The likelihood for missing process input and output data is low, as businesses closely track their purchase of production inputs. In those cases when an owner or operator uses direct measurement by a CO_2 CEMS, the missing data procedures would be the same as the Tier 4 requirements described for general stationary combustion sources in Section V.C of this preamble.

5. Selection of Data Reporting Requirements

The proposed rule would require reporting of the total annual CO_2 and CH_4 emissions for each electric arc furnace at a ferroalloy production facility, as well as any stationary fuel combustion emissions. In addition we propose that additional information which forms the basis of the emissions estimates also be reported so that we can understand and verify the reported emissions. This additional information includes the total number of electric arc furnaces operated at the facility, the facility ferroalloy product production capacity, the annual facility production quantity for each ferroalloy product, the number of facility operating hours in calendar year, and quantities of carbon inputs and outputs if applicable. A complete list of data to be reported is included in the proposed 40 CFR part 98, subparts A and K.

6. Selection of Records That Must Be Retained

Maintaining records of the information used to determine the reported GHG emissions are necessary to enable us to verify that the GHG emissions monitoring and calculations were done correctly. We propose that all affected facilities maintain records of product production quantities, and number of facility operating hours each month. If you use the carbon balance procedure, you would record for each carbon-containing input material consumed or used and output material produced the monthly material quantity, monthly average carbon content determined for material, and records of the supplier provided information or analyses used for the determination. If you use the CEMS procedure, you would maintain the CEMS measurement records.

L. Fluorinated GHG Production

1. Definition of the Source Category

This source category covers emissions of fluorinated GHGs that occur during the production of HFCs, PFCs, SF_6, NF_3, and other fluorinated GHGs such as fluorinated ethers. Specifically, it covers emissions that are never counted as ''mass produced'' under the proposed requirements for suppliers of industrial GHGs discussed in Section OO of this preamble. These emissions include fluorinated GHG products that are emitted upstream of the production measurement and fluorinated GHG byproducts that are generated and emitted either without or despite recapture or destruction.[71] These emissions exclude generation and emissions of HFC–23 during the production of HCFC–22, which are discussed in Section O of this preamble.

Emissions can occur from leaks at flanges and connections in the production line, during separation of byproducts and products, during occasional service work on the production equipment, and during the filling of tanks or other containers that are distributed by the producer (e.g., on trucks and railcars). Fluorinated GHG emissions from U.S. facilities producing fluorinated GHGs are estimated to range from 0.8 percent to 2 percent of the amount of fluorinated GHGs produced, depending on the facility.

In 2006, 12 U.S. facilities produced over 350 million metric tons CO_2e of HFCs, PFCs, SF_6, and NF_3. These facilities are estimated to have emitted approximately 5.3 million metric tons CO_2e of HFCs, PFCs, SF_6, and NF_3, based on an emission rate of 1.5 percent. We estimate that an additional 6 facilities produced approximately 1 million metric tons CO_2e of fluorinated anesthetics. At an emission rate of 1.5 percent, these facilities would emit approximately 15,000 metric tons CO_2e of these anesthetics.

The production of fluorinated gases causes both combustion and fluorinated GHG emissions. Fluorinated GHG production facilities would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary fuel combustion. In addition, these facilities would be required to report their production of industrial GHGs under proposed 40 CFR part 98, subpart OO. This section of the preamble discusses only the procedures for calculating and reporting emissions of fluorinated GHGs.

2. Selection of Reporting Threshold

We propose that owners and operators of facilities estimate and report fluorinated GHG and combustion emissions if those emissions together exceed 25,000 metric tons CO_2e.

In developing the threshold, we considered emissions 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 and their capacity equivalents. Facility-specific emissions were estimated by multiplying an emission factor of 1.5 percent by the estimated production at each facility. The capacity thresholds were developed based on emissions of fluorinated GHGs, assuming full capacity utilization and an emission rate of 2 percent of production. Because EPA had little information on combustion-related emissions at fluorinated GHG production facilities, these emissions were not incorporated into the capacity thresholds or the threshold analysis. Table L–1 of this preamble illustrates the HFC, PFC, SF_6, and NF_3 emissions

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[71] Byproducts that are emitted or destroyed at the production facility are excluded from the proposed definition of ''produce a fluorinated GHG.'' Any HFC–23 generated during the production of HCFC–22 is also excluded from this definition, even if the HFC–23 is recaptured. However, other fluorinated GHG byproducts that are recaptured for any reason would be considered to be ''produced.''

and facilities that would be covered under these various thresholds.

Table L–1. Threshold Analysis for Fluorinated GHG Emissions From Production of HFCs, PFCs, SF_6, and NF_3

Threshold level (metric tons CO_2e/r)	Total national emissions (metric tons CO_2e)	Number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e	Percent	Number	Percent
Emission-Based Thresholds						
1,000	5,300,000	12	5,300,000	100	12	100
10,000	5,300,000	12	5,300,000	100	12	100
25,000	5,300,000	12	5,300,000	100	12	100
100,000	5,300,000	12	5,100,000	97	9	75
Production Capacity-Based Thresholds						
50,000	5,300,000	12	5,300,000	100	12	100
500,000	5,300,000	12	5,300,000	100	12	100
1,250,000	5,300,000	12	5,300,000	100	12	100
5,000,000	5,300,000	12	5,200,000	98	10	83

As can be seen from the tables, most HFC, PFC, SF_6, and NF_3 production facilities would be covered by all emission- and capacity-based thresholds. Although we do not have facility-specific production information for producers of fluorinated anesthetics, we believe that few or none of these facilities are likely to have emissions above the proposed threshold.

EPA requests comment on whether it should adopt a capacity-based threshold for this sector, and if so, what fluorinated GHG and combustion-related emission rates should be used to develop this threshold. Where EPA has reasonably good information on the relationship between production capacity and emissions, and where this relationship does not vary excessively from facility to facility, EPA is generally proposing capacity-based thresholds to make it easy for facilities to determine whether or not they must report. In this case, however, EPA has little data on combustion emissions and their likely magnitude compared to fluorinated GHG emissions from this source.

As noted above, the capacity thresholds in Table L–1 of this preamble were developed based on a fluorinated GHG emission rate of 2 percent of production. While EPA believes that this emission rate is an upper-bound for fluorinated GHGs, neither the rate nor the thresholds account for combustion-related emissions. Thus, it is possible that the production capacities listed in Table L–1 of this preamble are inappropriately high.

In the event that a capacity-based threshold were adopted, facilities would be required to multiply the production capacity of each production line by the GWP of the fluorinated GHG produced on that line. Facilities would then be required to sum the resulting CO_2e capacities across all lines. Where more than one fluorinated GHG could be produced by a production line, yielding more than one possible production capacity for that line in CO_2e terms, facilities would be required to use the highest possible production capacity (in CO_2e terms) in their threshold calculations.

A full discussion of the threshold selection analysis is available in the Fluorinated GHG Production TSD (EPA–HQ–OAR–2008–0508–012). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

In developing this proposed rule, we reviewed a number of protocols for estimating fluorinated GHG emissions from fluorocarbon production, such as the 2006 IPCC Guidelines. In general, these protocols present three methods. In the first approach, a default emission factor is applied to the total production of the plant. In the second approach, fluorinated GHG emissions are equated to the difference between the mass of reactants fed into the process and the sum of the masses of the main product and those of any by-products and/or wastes. In the third approach, the composition and mass flow rate of the gas streams actually vented to the atmosphere are monitored either continuously or during a period long enough to establish an emission factor.

If you produce fluorinated GHGs, we are proposing that you monitor fluorinated GHG emissions using the second approach, known as the mass-balance or yield approach. There are two variants of the mass-balance approach. In the first variant, only some of the reactants and products, including the fluorinated GHG product, are considered. In the second variant, all of the reactants, products, and by-products are considered. Both variants are discussed in more detail in the Fluorinated GHG Production TSD (EPA–HQ–OAR–2008–0508–012).

We are proposing that you monitor emissions using the first variant. In this approach, you would calculate the difference between the expected production of each fluorinated GHG based on the consumption of reactants and the measured production of that fluorinated GHG, accounting for yield losses related to byproducts (including intermediates permanently removed from the process) and wastes. Yield losses that could not be accounted for would be attributed to emissions of the fluorinated GHG product. This calculation would be performed for each reactant, and estimated emissions of the fluorinated GHG product would be equated to the average of the results obtained for each reactant. If fluorinated GHG byproducts were produced and were not completely recaptured or completely destroyed, you would also estimate emissions of each fluorinated GHG byproduct.

To carry out this approach, you would daily weigh or meter each reactant fed into the process, the primary fluorinated GHG produced by the process, any reactants permanently removed from the process (i.e., sent to the thermal oxidizer or other equipment, not immediately recycled back into the process), any byproducts generated, and any streams that contain the product or byproducts and that are recaptured or destroyed. For these measurements you would be required to use scales and/or flowmeters with an accuracy and precision of 0.2 percent of full scale. If monitored process streams included more than one component (product, byproducts, or other materials) in more than trace concentrations,[72] you would be required to monitor concentrations of products and byproducts in these streams at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. Finally, you would be required to perform daily mass balance calculations for each product produced.

In general, we understand that production facilities already perform these measurements and calculations to the proposed level of accuracy and precision in order to monitor their processes and yields. However, we request comment on this issue. We specifically request comment on the proposed scope and frequency of process stream concentration measurements. As noted above, concentration measurements would be triggered when products or byproducts occur in more than trace concentrations with other components in process streams (which include waste streams). However, it is possible that products or byproducts could occur in more than trace concentrations but still result in negligible yield losses (e.g., less than 0.2 percent). In this case, ignoring these losses may not significantly affect the accuracy of the overall GHG emission estimate. (This issue is discussed in more detail in the Fluorinated GHG Production TSD (EPA–HQ–OAR–2008–0508–012).) Similarly, decreasing the frequency of stream sampling may not have a significant impact on accuracy or precision if previous monitoring has shown that the concentrations of products and byproducts in process streams are stable or vary in a predictable and quantifiable way (e.g., seasonally due to differences in condenser cooling water temperature).

EPA recognizes that the proposed mass-balance approach would assume that all yield losses that are not accounted for are attributable to emissions of the fluorinated GHG product. In some cases, the losses may be untracked emissions or other losses of reactants or fluorinated by-products. In general, EPA understands that reactant flows are measured at the inlet to the reactor; thus, any losses of reactant that occur between the point of measurement and the reactor are likely to be small. However, reactants that are recovered from the process, whether they are recycled back into it or removed permanently, may experience some losses that the proposed method does not account for. EPA requests comment on the extent to which such losses occur, and how these might be measured.

Fluorocarbon by-products, according to the IPCC Guidelines, generally have ‘‘radiative forcing properties similar to those of the desired fluorochemical.’’ If this is always the case (with the exception of HFC–23 generated during production of HCFC–22, which is addressed in Section V.O of this preamble), then assuming by-product emissions are product emissions would not lead to large errors in estimating overall fluorinated GHG emissions. If the GWPs of emitted fluorinated by-products are sometimes significantly different from those of the fluorinated GHG product, and if the quantity of by-product emitted can be estimated (e.g., based on periodic or past sampling of process streams), then the quantity of emitted product could be adjusted to reflect this. EPA requests comment on whether it is necessary or practical to distinguish between emissions of fluorinated GHG products and emissions of fluorinated by-products, and if so, on the best approach for doing so.

We also request comment on the proposed accuracy and precision requirements for flowmeters and scales. If a waste or by-product stream is significantly smaller than the reactant and product streams, a less precise measurement of this stream (e.g., 0.5 percent) may not have a large impact on the precision of the fluorinated GHG emission estimate and may therefore be acceptable. Similarly, if a measurement is repeated multiple times over the course of the reporting period, the precision of individual measurements could be relaxed without seriously compromising the precision of the monthly or annual estimates. One way of adding flexibility to the precision requirements would be to require that the error of the fluorinated GHG emissions estimate be no greater than some fraction of the yield, e.g., 0.3 percent, on a monthly basis. Facilities could achieve this level of precision however they chose. We request comment on this issue and on the accuracy, precision, and cost of the proposed approach as a whole.

Analysis of Alternative Methods. EPA is not proposing the approach using the default emission factor. While this approach is simple, it is also highly imprecise; emissions in U.S. plants are estimated to vary from 0.8 percent to 2 percent of production, more than a factor of two.[73] Thus, applying a default factor (1.5 percent, for example) is likely to significantly overestimate emissions at some plants while significantly underestimating them at others.

EPA is not proposing the second variant of the mass-balance approach. This variant is implemented by comparing the total mass of reactants to the total mass of monitored products and byproducts, without regard for chemical identity. The drawbacks of this variant are that it is not the method currently used by facilities to track their production, and it would count losses of non-GHG products (e.g., HCl) as GHG emissions. EPA requests comment on this understanding and on the potential usefulness and accuracy of the second variant of the mass-balance approach for estimating fluorinated GHG emissions.

EPA is not proposing the third approach because it is our understanding that facilities do not routinely monitor their process vents, and therefore such monitoring is likely to be more expensive than the proposed mass-balance approach. However, the cost of monitoring may not be prohibitive, particularly if it is performed for a relatively short period of time for the purpose of developing an emission factor, similar to the approach for estimating smelter-specific slope coefficients for aluminum production.[74] Moreover, if the vent monitoring approach reduces the uncertainty of the emissions measurement by even 10 percent relative to the mass-balance approach, this would reduce the absolute uncertainty at the typical production facility by 40,000 metric tons CO_2e. (The extent to which uncertainty would be reduced would depend in part on the sensitivity and

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[72] EPA is proposing to define ‘‘trace concentration’’ as any concentration less than 0.1 percent by mass of the process stream.

[73] Fluorinated GHG Production TSD (EPA–HQ–OAR–2008–0508–012).

[74] Conversations with representatives of fluorocarbon producers indicate that robust emission factors could often be developed by monitoring emissions (and a related parameter, such as production) for one month under representative operating conditions. Where emissions vary seasonally (e.g., due to changes in condenser cooling water temperature), two separate monitoring periods of one month each would often suffice. However, the length and frequency of monitoring would depend on the variability of the process.

precision of the vent concentration measurements.)

For completeness, monitoring of process vents would need to be supplemented by monitoring of equipment leaks, whose emissions would not occur through process vents. To capture emissions from equipment leaks, we could require use of EPA Method 21 and the *Protocol for Equipment Leak Estimates* (EPA–453/R–95–017). The *Protocol* includes four methods for estimating equipment leaks. These are, from least to most accurate, the Average Emission Factor Approach, the Screening Ranges Approach, EPA Correlation Approach, and the Unit-Specific Correlation Approach. Most recent EPA leak detection and repair regulations require use of one of the Correlation Approaches in the *Protocol*. To use any approach other than the Average Emission Factor Approach, you would need to have (or develop) Response Factors relating concentrations of the target fluorinated GHG to concentrations of the gas with which the leak detector was calibrated. We understand that at least two fluorocarbon producers currently use methods in the *Protocol* to quantify their emissions of fluorinated GHGs with different levels of accuracy and precision.[75]

We request comment on the accuracies and costs of the approaches in the *Protocol* as they would be applied to fluorinated GHG production. We also request comment on the significance of equipment leaks compared to process vents as a source of fluorinated GHG emissions.

In addition, we request comment on whether we should require the vent monitoring approach, what sensitivity and precision would be appropriate for the vent concentration measurements, and on the increase in cost and improvements in accuracy and precision that would be associated with this approach relative to the proposed approach.

Emissions from Evacuation of Returned Containers. We request comment on whether you should be required to measure and report fluorinated GHG emissions associated with the evacuation of cylinders or other containers that are returned to the facility containing either residual GHGs (heels) or GHGs that would be reclaimed or destroyed. We are not proposing to require reporting of these emissions because they are not associated with new production; instead, they are downstream emissions associated with earlier production.[76] Requiring reporting of these emissions could therefore lead to double-counting.[77]

Nevertheless, according to the 2006 IPCC Guidelines, the overall emission rate of a production facility can increase by nearly an order of magnitude (up to 8 percent) if the residual GHG remaining in the cylinders is vented to the atmosphere. One method of tracking such emissions would be to subtract the quantities of GHG reclaimed (purified) and sold or otherwise sent back to users from the quantities of residual and used GHGs returned to the facility in cylinders by users. This approach would be similar to the mass-balance approach proposed for estimating SF_6 emissions from users and manufacturers of electrical equipment.

Emissions of Fluorinated GHGs Associated with Production of ODS. We request comment on whether you should be required to report emissions of fluorinated GHGs associated with production of ODS (other than emissions of HFC–23 associated with production of HCFC–22, which are discussed in Section O of this preamble). These emissions would be by-product emissions, for example of HFCs, since the definition of fluorinated GHGs excludes ODS. We specifically request comment on the likely magnitude of these emissions, both in absolute terms and relative to fluorinated GHG emissions from fluorinated GHG production. We believe that these emissions may occur due to the chemical similarities between HFCs, HCFCs, and CFCs and the common use of halogen replacement chemistry to produce them. Although production of HCFCs and CFCs is limited under the regulations implementing Title VI of the CAA, production of these substances for use as feedstocks is permitted to continue indefinitely.

4. Selection of Procedures for Estimating Missing Data

In the event that a scale or flowmeter normally used to measure reactants, products, by-products, or wastes fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, we are proposing that facilities be required to estimate these quantities using other measurements where these data are available. For example, facilities that ordinarily measure production by metering the flow into the day tank could use the weight of product charged into shipping containers for sale and distribution as a substitute. It is our understanding that the types of flowmeters and scales used to measure fluorocarbon production (e.g., Coriolis meters) are generally quite reliable, and therefore that it should rarely be necessary to rely solely on secondary production measurements. In general, production facilities rely on accurate monitoring and reporting of the inputs and outputs of the production process.

If concentration measurements are unavailable for some period, we are proposing that the facility use the average of the concentration measurements from just before and just after the period of missing data.

There is one proposed exception to these requirements: If either method would result in a significant under- or overestimate of the missing parameter, then the facility would be required to develop an alternative estimate of the parameter and explain why and how it developed that estimate.

We request comment on these proposed methods for estimating missing data.

5. Selection of Data Reporting Requirements

Under the proposed rule, owners and operators of facilities producing fluorinated GHGs would be required to report both their fluorinated GHG emissions and the quantities used to estimate them, including the masses of the reactants, products, by-products, and wastes, and, if applicable, the quantities of any product in the by-products and/or wastes (if that product is emitted at the facility). We are proposing that owners and operators report annual totals of these quantities.

Where fluorinated GHG production facilities have estimated missing data, you would be required to report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing

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[75] One producer estimates HFC and other fluorocarbon emissions by using the Average Emission Factor Approach. This approach simply assigns an average emission factor to each component without any evaluation of whether or how much that component is actually leaking. The second producer estimates emissions using the Screening Ranges Approach, which assigns different emission factors to components based on whether the concentrations of the target chemical are above or below 10,000 ppmv. This producer has developed a Response Factor for HCFC–22, which is present in the same streams as the HFC–23 whose leaks are being estimated. (HFC–23 emissions are discussed in Section O of this preamble.)

[76] Emissions from the filling or refilling of containers with new product may or may not be covered by proposed 40 CFR part 98, subpart L, depending on where production is measured. If production is measured upstream of filling, then the emissions would not be covered by proposed 40 CFR part 98, subpart L. If production is measured downstream of filling, then the emissions would be covered by subpart L.

[77] However, this double-counting could be avoided if the emissions from returned cylinders were clearly distinguished from other production facility emissions in the emissions report.

data, and the estimates of those data. Where the missing data was estimated by a method other than one of those specified, the owner or operator would be required to report why the specified method would lead to a significant under- or overestimate of the parameter(s) and the rationale for the methods used to estimate the missing data.

We propose that facilities report these data because the data are necessary to verify facilities' calculations of fluorinated GHG emissions. We request comment on these proposed reporting requirements.

6. Selection of Records That Must Be Retained

Under the proposed rule, owners and operators of facilities producing fluorinated GHGs would be required to retain records documenting the data reported, including records of daily and monthly mass-balance calculations and calibration records for flowmeters, scales, and gas chromatographs. These records are necessary to verify that the GHG emissions monitoring and calculations were performed correctly.

M. Food Processing

1. Definition of the Source Category

Food processing facilities prepare raw ingredients for consumption by animals or humans. Many facilities in the meat and poultry, and fruit, vegetable, and juice processing industries have on-site wastewater treatment. This can include the use of anaerobic and aerobic lagoons, screening, fat traps and dissolved air flotation. These facilities can also include onsite landfills for waste disposal. In 2006, CH_4 emissions from wastewater treatment at food processing facilities were 3.7 million metric tons CO_2e, and CH_4 emissions from onsite landfills were 7.2 million metric tons CO_2e. Data are not available to estimate stationary fuel combustion-related GHG emissions at food processing facilities.

Proposed requirements for stationary fuel combustion emissions are set forth in proposed 40 CFR part 98, subpart C.

Wastewater GHG emissions are described and considered in Section V.II of this preamble. For more information on wastewater treatment at food processing facilities, please refer to the Food Processing TSD (EPA–HQ–OAR–2008–0508–013).

Landfill GHG emissions are described and considered in Section V.HH of this preamble. For more information on landfills at food processing facilities, please refer to the Landfills TSD (EPA–HQ–OAR–2008–0508–034).

The sources of GHG emissions at food processing facilities that must be reported under the proposed rule are stationary fuel combustion, onsite landfills and onsite wastewater treatment.

2. Selection of Reporting Threshold

We considered using annual GHG emissions-based threshold levels 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 for food processing facilities. The proposed threshold for reporting emissions from food processing facilities is 25,000 metric tons CO_2e total emissions from combined stationary fuel combustion, on-site landfills, and on-site wastewater treatment. Table M–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE M–1. THRESHOLD ANALYSIS FOR FOOD PROCESSING FACILITIES

Threshold	National	Total	Emissions covered		Facilities covered	
			Metric tons CO_2e/year	Percent	Number	Percent
1,000 mtCO_2e	NE	5,719	NE	NE	802	14.0
10,000 mtCO_2e	NE	5,719	NE	NE	170	3.0
25,000 mtCO_2e	NE	5,719	NE	NE	100	1.7
100,000 mtCO_2e	NE	5,719	NE	NE	10	0.2

NE = Not Estimated.

Data were unavailable at the time of this analysis to estimate stationary combustion emissions onsite, or the co-location of landfills and wastewater treatment at food processing faculties. Facility coverage based on onsite wastewater GHG emissions and landfill GHG emissions was estimated as described in the Wastewater Treatment TSD and Landfills TSD (EPA–HQ–OAR–2008–0508–035) and (EPA–HQ–OAR–2008–0508–034). We estimate that at the 25,000 metric tons CO_2e threshold, a small percentage of facilities are covered by this rule, resulting in potentially a large percentage of emissions data reporting from this significant emissions source but avoiding small facilities.

For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Refer to Sections V.C, V.HH, and V.II of this preamble for monitoring methods for general stationary fuel combustion sources, landfills, and wastewater treatment, respectively, occurring on-site at food production facilities.

4. Selection of Procedures for Estimating Missing Data

Refer to Sections V.C, V.HH, and V.II of this preamble for procedures for estimating missing data for general stationary fuel combustion sources, landfills, and wastewater treatment, respectively, occurring on-site at food processing facilities.

5. Selection of Data Reporting Requirements

Refer to Sections V.C, V.HH, and V.II of this preamble for reporting requirements for general stationary fuel combustion, landfills, and wastewater treatment, respectively, occurring on-site at food processing facilities. In addition, you would be required to report the quantity of CO_2 captured for use (if applicable) and the end use, if known.

6. Selection of Records That Must Be Maintained

Refer to Sections V.C, V.HH, and V.II of this preamble for recordkeeping requirements for general stationary fuel combustion sources, landfills, and wastewater treatment, respectively, occurring on-site at food processing facilities.

N. Glass Production

1. Definition of the Source Category

Glass is a common commercial item that is produced by melting a mixture of minerals and other substances, then cooling the molten materials in a manner that prevents crystallization. Glass is typically classified as container glass, flat (or window) glass, or pressed and blown glass. Pressed and blown glass includes textile fiberglass, which is used primarily as a reinforcement material in a variety of products, as well as other types of glass. Wool fiberglass, which is commonly used for insulation, is generally classified separately from textile fiberglass and other pressed and blown glass. However, for the purposes of GHG reporting, wool fiberglass production is included in the glass manufacturing source category.

Glass can be produced using a variety of raw material formulations. Most commercial glass is made using a soda-lime glass formulation, which consists of silica (SiO_2), soda (Na_2O), and lime (CaO), with small amounts of alumina (Al_2O_3), magnesia (MgO), and other minor ingredients. Several specialty glasses, including fiberglass, are made using borosilicate or aluminoborosilicate recipes, which can consist primarily of silica and boric oxides, along with varying amounts of soda, lime, alumina, and other minor ingredients. Other formulations used in the production of specialty glasses include aluminosilicate and lead silicate formulations.

Major carbonates used in the production of glass are limestone ($CaCO_3$), dolomite ($CaMg(CO_3)_2$), and soda ash (Na_2CO_3). The use of these carbonates in the furnace during glass manufacturing results in a complex high-temperature reaction that leads to process-related GHG emissions. Glass manufacturers may also use recycled scrap glass (cullet) in the production of glass, thereby reducing the carbonate input to the process and resulting GHG emissions.

National emissions from glass manufacturing were estimated to be 4.43 million metric tons CO_2e (0.1 percent of U.S. GHG emissions) in 2005. These emissions include both process-related emissions (CO_2) and on-site stationary combustion emissions (CO_2, CH_4, and N_2O) from 374 glass manufacturing facilities across the U.S. and Puerto Rico. Process-related emissions account for 1.65 million metric tons CO_2, or 37 percent of the total, while on-site stationary combustion sources account for the remaining 2.78 million metric tons CO_2e emissions.

For additional background information on glass manufacturing, refer to the Glass Manufacturing TSD (EPA–HQ–OAR–2008–0508–014).

2. Selection of Reporting Threshold

In developing the threshold for glass manufacturing, we considered an emissions-based threshold 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. Table N–1 of this preamble summarizes the emissions and number of facilities that would be covered under these various thresholds.

TABLE N–1. THRESHOLD ANALYSIS FOR GLASS MANUFACTURING

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	4,425,269	374	4,336,892	98	217	58
10,000	4,425,269	374	4,012,319	91	158	42
25,000	4,425,269	374	2,243,583	51	55	15
100,000	4,425,269	374	207,535	5	1	0.3

The glass manufacturing industry is heterogeneous in terms of the types of facilities. There are some relatively large, emissions-intensive facilities, but small artisan shops are common as well. For example, at a 1,000 metric tons CO_2e threshold, 98 percent of emissions would be covered, with only 58 percent of facilities being required to report.

The proposed threshold for reporting emissions from glass manufacturing is 25,000 metric tons CO_2e. We are proposing a 25,000 metric tons CO_2e threshold to reduce the compliance burden on small businesses, while still including half of the GHG emissions from the industry. In comparison to the 100,000 metric tons CO_2e threshold, the 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 number of reporters. We consider this a significant coverage of the emissions, while impacting a relatively small portion of the industry.

For a full discussion of the threshold analysis, please refer to the Glass Manufacturing TSD (EPA–HQ–OAR–2008–0508–014). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many of the domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related CO_2 emissions from glass manufacturing (e.g., the 2006 IPCC Guidelines, U.S. Inventory, the Technical Guidelines for the DOE 1605(b), and the EU Emissions Trading System). These methodologies coalesce around four different options. Two options are output-based (production-based): One applies appropriate emission factors to the type of glass produced, and the other applies a default emission factor to total glass production. A third option is based on measuring the carbonate input to the furnace. The final option uses direct measurement to estimate emissions.

Option 1. The first production-based option we considered applies a default emission factor to the total quantity of all glass produced, correcting for the amount of cullet supplied to the process.

Option 2. The second production-based approach we considered applies default emission factors to each of the types of glass produced at the facility (e.g., container, flat, pressed and blown, and fiberglass).

Option 3. The carbonate-input approach calculates emissions based on actual input data and the mass fractions of the carbonates that are volatilized and emitted as CO_2. More specifically, this option considers the type, quantity, and mass fraction of carbonate inputs to the furnace and develops a facility-specific emission factor.

Option 4. This approach directly measures emissions using a CEMS. CEMS can be used to measure both combustion-related and process-related CO_2 emissions from glass melting furnaces. These emissions generally are exhausted through a common furnace stack. Therefore, separate CEMS would not be needed to quantify both types of emissions from glass melting furnaces.

Proposed Option. Under the proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions, you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, the proposed monitoring method would require estimating combustion emissions and process emissions separately. For combustion emissions, you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. For process emissions, the carbonate input approach (Option 3) is proposed. This section of the preamble provides only those procedures for calculating and reporting process-related emissions.

To estimate process CO_2 emissions from glass melting furnaces, we propose that facilities measure the type, quantity, and mass fraction of carbonate inputs to each furnace and apply the appropriate emission factors for the carbonates consumed. This method for determining process emissions is consistent with the IPCC Tier 3 method.

The proposed rule distinguishes between carbonate-based minerals and carbonate-based raw materials used in glass production. Carbonate-based raw materials are fired in the furnace during glass manufacturing. These raw materials are typically limestone, which is primarily $CaCO_3$; dolomite, which is primarily $CaMg(CO_3)CO_2$; and soda ash, which is primarily $NaCO_2CO_3$. Because it is the calcination of the mineral fraction of the raw material (e.g., $CaCO_3$ fraction in limestone) that leads to CO_2 emissions, the purity of the limestone or other carbonate input is important for emissions estimation.

In order to assess the composition of the carbonate input, we propose that facilities use data from the raw material supplier to determine the carbonate-based mineral mass fraction of the carbonate-based raw materials charged to an affected glass melting furnace. As an alternative to using data provided by the supplier, facilities can assume a value of 1.0 for the mass fraction of the carbonate-based mineral in the carbonate-based raw material. We also propose that emissions are estimated under the assumption that 100 percent of the carbon in the carbonate-based raw materials is volatilized and released from the furnace as CO_2. Using the carbonate-based mineral mass fractions, the carbonate-based raw material feed rates, and the emission factors, the mass emissions of CO_2 emitted from a glass melting furnace can be determined.

Using values of 1.0 for the carbonate-based mineral mass fractions is based on the assumption that the raw materials consist of 100 percent of the respective carbonate-based mineral (i.e., the limestone charged to the furnace consists of 100 percent $CaCO_3$, the dolomite charged consists of 100 percent $CaMg(CO_3)_2$, and the soda ash consists of 100 percent Na_3CO_3). Using this assumption generally overestimates CO_2 emissions. However, given the relative purity of the raw materials used to produce glass, this method provides accurate estimates of process CO_2 emissions from glass melting furnaces, while avoiding the costs associated with sampling and analysis of the raw materials.

We have concluded that the carbonate input method specified in the proposed option is more certain as it involves measuring the consumption of each carbonate material charged to a glass melting furnace. According to the 2006 IPCC Guidelines, the uncertainty involved in the proposed carbonate input approach is 1 to 3 percent; in contrast, the uncertainty with using the default emission factor and cullet ratio for the production-based approach is 60 percent.

We considered use of a CO_2 CEMS which does tend to provide the most accurate CO_2 emissions measurements and can measure both the combustion- and process-related CO_2 emissions. However, given the limited variability in the process inputs and outputs contributing to emissions from glass production, installation of CEMS would require significant additional burden to facilities given that few glass facilities currently have CO_2 CEMS.

We also considered, but decided not to propose, the production-based default emission factor-based approach referenced above for quantifying process-related CO_2 emissions based on the quantity of glass produced. In general, the default emission factor method results in less certainty because the method involves multiplying production data by emission factors that are based on default assumptions regarding carbonate-based mineral content and degree of calcination.

As part of normal business practices, glass manufacturing plants maintain the records that would be needed to calculate emissions under the proposed option. Given the greater accuracy associated with the input method and the minimal additional burden, we have determined that this requirement would not add additional burden to current practices at the facility, while providing accurate estimates of process-based CO_2 emissions.

The various approaches to monitoring GHG emissions are elaborated in the Glass Manufacturing TSD (EPA–HQ–OAR–2008–0508–014).

4. Selection of Procedures for Estimating Missing Data

To estimate process emissions of CO_2 based on carbonate input, data are needed on the carbonate chemical analysis of the carbonate-based raw materials and the carbonate-based raw material input rate (process feed rate). Glass manufacturing facilities must monitor raw material feed rate carefully in order to maintain product quality. Therefore, we do not expect missing data on raw material input to be an issue. However, if these data were missing, we propose requiring facilities to use average data from the previous and following months for the mass of carbonate-based raw materials charged to the furnace. Given that glass furnaces generally operate continuously at a relatively constant production rate, we do not expect much variation in the amounts of carbonates charged to the furnace from month to month. Furthermore, it would be unusual for a glass manufacturing plant to change its glass formulation. Therefore, we believe using average data from the previous and following months would provide a reliable estimate of raw materials charged.

For missing data on carbonate-based mineral mass fractions, we propose requiring facilities to assume that the mass fraction of each carbonate-based mineral in the carbonate-based raw materials is 1.0. This assumption may result in a slight overestimate of emissions, but should still provide a reasonably accurate estimate of emissions for the period with missing data.

5. Selection of Data Reporting Requirements

We propose that facilities report total annual emissions of CO_2 from each affected continuous glass melting furnace, as well as any stationary fuel combustion emissions. The proposed rule would also require facilities to report the quantity of each carbonate-based raw material charged to each continuous glass melting furnace in tons per year, and the quantity of glass produced by each continuous glass melting furnace. For facilities that calculate process emissions of CO_2 based on the mass fractions of carbonate-based minerals, the proposed rule would require facilities to report those values. These data are requested because they provide the basis for calculating process-based CO_2 emissions and are needed for us to understand the emissions data and verify the reasonableness of the reported emissions. The data on raw material composition and charge rates are needed to verify process-based emissions of CO_2. The data on glass production are needed to verify that the reported quantities of raw materials charged to continuous furnaces are reasonable. The production data also can be used to identify potential outliers.

A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and N.

6. Selection of Records That Must Be Retained

In addition to the data to be reported, we propose that facilities retain monthly records of the data used to calculate GHG emissions. This would include records of the amounts of each carbonate-based raw material charged to a continuous glass melting furnace and glass production (by type). This requirement would be consistent with current business practices and the reporting requirements for emissions of other pollutants for the glass manufacturing industry.

The proposed rule also would require facilities to retain the results of all tests used to determine carbonate-based mineral mass fractions, as well as any other supporting information used in the calculation of GHG emissions. These data are directly used to calculate emissions that are reported and are necessary to enable verification that the GHG emissions monitoring and calculations were performed correctly.

A full list of records that must be retained on site is included in proposed 40 CFR part 98, subparts A and N.

O. HCFC–22 Production and HFC–23 Destruction

1. Definition of the Source Category

This source category includes the generation, emissions, sales, and destruction of HFC–23. The source category includes facilities that produce HCFC–22, generating HFC–23 in the process. This source category also includes facilities that destroy HFC–23, which are sometimes, but not always, also facilities that produce HCFC–22.

HFC–23 is generated during the production of HCFC–22. HCFC–22 is primarily employed in refrigeration and A/C systems and as a chemical feedstock for manufacturing synthetic polymers. Because HCFC–22 depletes stratospheric O_3, its production for non-feedstock uses is scheduled to be phased out by 2020 under the CAA. Feedstock production, however, is permitted to continue indefinitely.

HCFC–22 is produced by the reaction of chloroform ($CHCl_3$) and hydrogen fluoride (HF) in the presence of a catalyst, $SbClB_5$. In the reaction, the chlorine in the chloroform is replaced with fluorine, creating HCFC–22. Some of the HCFC–22 is over-fluorinated, producing HFC–23. Once separated from the HCFC–22, the HFC–23 may be vented to the atmosphere as an unwanted by-product, captured for use in a limited number of applications, or destroyed.

2006 U.S. emissions of HFC–23 from HCFC–22 production were estimated to be 13.8 million metric tons CO_2e. This quantity represents a 13 percent decline from 2005 emissions and a 62 percent decline from 1990 emissions despite an 11 percent increase in HCFC–22 production since 1990. Both declines are primarily due to decreases in the HFC–23 emission rate. The ratio of HFC–23 emissions to HCFC–22 production has decreased from 0.022 to 0.0077 since 1990, a reduction of 66 percent. These decreases have occurred because an increasing fraction of U.S. HCFC–22 production capacity has adopted controls to reduce HFC–23 emissions. Three HCFC–22 production facilities operated in the U.S. in 2006, two of which used recapture and/or thermal oxidation to significantly lower their HFC–23 emissions. All three plants are part of a voluntary agreement to report and reduce their collective HFC–23 emissions.

The production of HCFC–22 and destruction of HFC–23 causes both combustion and HFC–23 emissions. HCFC–22 production and HFC–23 destruction facilities are required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary fuel combustion. This section of the preamble provides only those procedures for calculating and reporting generation, emissions, sales, and destruction of HFC–23.

For additional background information on HCFC–22 production, please refer to the HCFC–22 Production and HFC–23 Destruction TSD (EPA–HQ–OAR–2008–0508–015).

2. Selection of Reporting Threshold

We propose that all facilities producing HCFC–22 be required to report under this rule. Facilities destroying HFC–23 but not producing HCFC–22 would be required to report if they destroyed more than 25,000 metric tons CO_2e of HFC–23.

For HCFC–22 production facilities, 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 and capacity-based thresholds equivalent to these. The capacity-based thresholds are shown in Table O–1 of this preamble, and are based on full utilization of HCFC–22 capacity and the emission rate given for older plants in the 2006 IPCC Guidelines. (One plant is relatively new, but the emission rate for older plants was used to be consistent and somewhat conservative.)

TABLE O–1. CAPACITY-BASED THRESHOLDS

Threshold level (HCFC–22 capacity in tons)	Total national emissions (metric tons CO_2e)	Total national facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
2	13,848,483	3	13,848,483	100	3	100
21	13,848,483	3	13,848,483	100	3	100
53	13,848,483	3	13,848,483	100	3	100
214	13,848,483	3	13,848,483	100	3	100

Our analysis showed that all of the facilities, which have capacities ranging from 18,000 to 100,000 metric tons of HCFC–22, exceeded all of the capacity-based thresholds by wide margins. The smallest plant exceeded the largest capacity-based threshold by a factor of 85.

We are not presenting a table for emission-based thresholds because we do not have facility-specific emissions information. (Under the voluntary emission reduction agreement, total emissions from the three facilities are aggregated by a third party, who submits only the total to us.) Since two of the three facilities destroy or capture most or all of their HFC–23 by-product, one or both of them probably have emissions below at least some of the emission-based thresholds discussed above. However, if the thermal oxidizers malfunctioned, were not operated properly, or were unused for some other reason, emissions of HFC–23 from each of the plants could easily exceed all thresholds. Reporting is therefore important both for tracking the considerable emissions of facilities that do not use thermal oxidation and for verifying the performance of thermal oxidation where it is used. For this reason, we propose that all HCFC–22 manufacturers report their HFC–23 emissions.

We are aware of one facility that destroys HFC–23 but does not produce HCFC–22. Although we do not know the precise quantity of HFC–23 destroyed by this facility, the Agency has concluded that the facility destroys a substantial share of the HFC–23 generated by the largest HCFC–22 production facility in the U.S. If the destruction facility destroys even one percent of this HFC–23, it is likely to destroy considerably more than the proposed threshold of 25,000 metric tons CO_2e.

For additional background information on the threshold analysis for HCFC–22 production, please refer to the HCFC–22 Production and HFC–23 Destruction TSD (EPA–HQ–OAR–2008–0508–015). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

a. Review of Monitoring Methods

In developing these proposed requirements, we reviewed several protocols and guidance documents, including the 2006 IPCC Guidelines, guidance developed under our voluntary program for HCFC–22 manufacturers, the WRI/WBCSD protocols, the TRI, the TSCA Inventory Update Rule, The DOE 1605(b) Voluntary Reporting Program, EPA Climate Leaders, and TRI.

We also considered the findings and conclusions of a recent report that closely reviewed the methods that facilities use to estimate and assure the quality of their estimates of HCFC–22 production and HFC–23 emissions. As noted above, the production facilities currently estimate and report these quantities to us (across all three plants) under a voluntary agreement. The report, by RTI International, is entitled ‘‘Verification of Emission Estimates of HFC–23 from the Production of HCFC–22: Emissions from 1990 through 2006’’ and is available in the docket for this rulemaking.

The 2008 Verification Report found that the estimation methods used by the three HCFC–22 facilities currently operating in the U.S. were all equivalent to IPCC Tier 3 methods. Under the Tier 3 methodology, facility-specific emissions are estimated based on direct measurement of the HFC–23 concentration and the flow rate of the streams, accounting for the use of emissions abatement devices (thermal oxidizers) where they are used. In general, Tier 3 methods for this source category yield far more accurate estimates than Tier 2 or Tier 1 methods. Even at the Tier 3 level, however, the emissions estimation methods used by the three facilities differed significantly in their levels of absolute uncertainty. The uncertainty of the one facility that does not thermally destroy its HFC–23 emissions dominates the uncertainty for the national emissions from this source category.

In general, the methods proposed in this rule are very similar to the procedures already being undertaken by the facilities to estimate HFC–23 emissions and to assure the quality of these estimates. The differences (and the rationale for them) are discussed in the HCFC–22 Production and HFC–23 Destruction TSD (EPA–HQ–OAR–2008–0508–015).

b. Proposed Monitoring Methods

This section of the preamble includes two proposed monitoring methods for HCFC–22 production facilities and one for HFC–23 destruction facilities. The proposed monitoring methods differ for HCFC–22 facilities that do and do not use a thermal oxidizer connected to the HCFC–22 production equipment. All the monitoring methods rely on measurements of HFC–23 concentrations in process or emission streams and on measurements of the flow rates of those streams, although the proposed frequency of these measurements varies.

Proposed Methods for Estimating HFC–23 Emissions from Facilities that Do Not Use a Thermal Oxidizer or Facilities that Use a Thermal Oxidizer that is Not Directly Connected to the HCFC–22 Production Equipment. Under the proposed rule, you would be required to:

(1) Monitor the concentration of HFC–23 in the reaction product stream containing the HFC–23 (which could be either the HCFC–22 or the HCl product stream) on at least a daily basis. This proposed requirement is intended to account for day-to-day fluctuations in the rate at which HFC–23 is generated; this rate can vary depending on process conditions.

(2) Monitor the mass flow of the product stream containing the HFC–23 either directly or by weighing the other reaction product. The other product could be either HCFC–22 or HCl. Plants would be required to make or sum these measurements on at least a daily basis. If the HCFC–22 or HCl product were measured significantly downstream of the reactor (e.g., at storage tanks or the shipping dock), facilities would be required to add a factor that accounted for losses to the measurement. This factor would be 1.5 percent or another factor that could be demonstrated, to the satisfaction of the Administrator, to account for losses. This adjustment is intended to account for upstream product losses, which are estimated to range from one to two percent. Without the adjustment, HCFC–22 production and therefore HFC–23 generation at affected facilities would be systematically underestimated (negatively biased). A one-to two-percent underestimate could translate into an underestimate of HFC–23 emissions of 100,000 metric tons CO_2e or more for each affected facility.

We request comment on this proposed approach for compensating for the negative bias caused by HCFC–22 emissions. We specifically request comment on the 1.5 percent factor, which is the midpoint of the one-to-two-percent range of product loss rates cited by the affected facility. We also request comment on what methods and data would be required to verify a loss rate other than 1.5 percent, if a facility wished to demonstrate a lower loss rate. One option would be a mass-balance approach using measurements with very fine precisions (e.g., 0.2 percent or better).

(3) Facilities that do not use a thermal oxidizer connected to the HCFC–22

production equipment would also be required to estimate the mass of HFC–23 produced either by multiplying the HFC–23 concentration measurement by the mass flow of the stream containing both the HFC–23 and the other product or by multiplying the ratio of the concentrations of HFC–23 and of the other product by the mass of the other product.

(4) Facilities would also be required to measure the masses of HFC–23 sold or sent to other facilities for destruction. This step would ensure that any losses of HFC–23 during filling of containers were included in the HFC–23 emission estimates for facilities that capture HFC–23 for use as a product or for transfer to a destruction facility.

(5) Facilities would also be required to estimate the HFC–23 emitted by subtracting the masses of HFC–23 sold or sent for destruction from the mass of HFC–23 generated.

This calculation assumes that all production that is not sold or sent to another facility for destruction is emitted. Such emissions may be the result of the packaging process; additional emissions can be attributed to the number of flanges in a line and other on-site equipment that is specific to each facility.

Proposed Methods for Estimating HFC–23 Emissions from Plants that Use a Thermal Oxidizer Connected to the HCFC–22 Production Equipment. Under the proposed rule, you would be required to estimate HFC–23 emissions from equipment leaks, process vents, and the thermal oxidizer. To estimate emissions from leaks, you would be required to estimate the number of leaks using EPA Method 21 of 40 CFR part 60, Appendix A–7 and a leak definition of 10,000 ppmv. Leaks registering above and below 10,000 ppmv would be assigned different default emission rates, depending on the component and service (gas or light liquid). These leak rates would be drawn from Table 2–5 from the *Protocol for Equipment Leak Estimates* (EPA–453/R–95–017) and data on the concentration of HFC–23 in the process stream.[78] (The relevant portions of Table 2–5 are included in the proposed regulatory text for this rule.) To estimate emissions from process vents, you would be required to use the results of annual emissions tests at process vents, adjusting for changes in HCFC–22 production rates since the measurements occurred. Tests would have to be conducted in accordance with EPA Method 18 of 40 CFR part 60, Appendix A–6, *Measurement of Gaseous Organic Compounds by Gas Chromatography.* Although HFC–23 emissions from process vents are believed to be quite low, this monitoring would ensure that any year-to-year variability in the emission rate was captured by the reporting. Finally, to estimate emissions from the thermal oxidizer, you would be required to apply the DE of the oxidizer to the mass of HFC–23 fed into the oxidizer.

Destruction. Under the proposed rule, if you use thermal oxidation to destroy HFC–23 you would be required to measure the quantities of HFC–23 fed into the oxidizer. You would also be required to account for any decreases in the DE of the oxidizer that occurred when the oxidizer was not operating properly (as defined in State or local permitting requirements and/or oxidizer manufacturer specifications). Finally, you would be required to perform annual HFC–23 concentration measurements by gas chromatography to confirm that emissions from the oxidizer were as low as expected based on the rated DE of the device. If emissions were found to be higher, then facilities would have the option of using the DE implied by the most recent measurements or of conducting more extensive measurements of the DE of the device.

As discussed in the HCFC–22 Production and HFC–23 Destruction TSD (EPA–HQ–OAR–2008–0508–015), the initial testing and parametric monitoring that facilities currently perform on their oxidizers provides general assurance that the oxidizer is performing correctly. However, the proposed requirement to measure HFC–23 concentrations at the oxidizer outlet would provide additional assurance at relatively low cost. Even a one- or two-percent decline in the DE of the oxidizer could lead to emissions of over 100,000 metric tons CO_2e, making this a particularly important factor to monitor accurately.

Startups, shutdowns, and malfunctions. Under the proposed rule, if you produce HCFC–22 you would be required to account for HFC–23 production and emissions that occur as a result of startups, shutdowns, and malfunctions. This would be done either by recording HFC–23 production and emissions during these events, or documenting that these events do not result in significant HFC–23 production and/or emissions. Depending on the circumstances, startups, shutdowns, and malfunctions (including both the process equipment and any thermal oxidation equipment) can be significant sources of emissions, and the Agency believes that emissions during these process disturbances should therefore be tracked.

Precision and Accuracy Requirements. We are proposing to require that HCFC–22 production facilities and HFC–23 destruction facilities monitor the masses that would be reported under this rule using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. Our understanding is that some HCFC–22 production facilities currently use devices with this level of accuracy and precision. However, flowmeters with considerably better precisions are available, e.g., 0.2 percent. We request comment on the option of requiring plants to use flowmeters or scales with an accuracy and precision of 0.2 percent or some other precision better than 1 percent. Given the large quantities of HFC–23 generated by each plant, this higher precision may be appropriate.

We are also proposing to require that HCFC–22 production facilities and HFC–23 destruction facilities measure concentrations using equipment and methods with an accuracy and precision of 5 percent or better at the concentrations of the samples.

Calibration Requirements. Under the proposed rule, if you produce HCFC–22 or destroy HFC–23 you would be required to perform the following activities to assure the quality of their measurements and estimates:

(1) Calibrate gas chromatographs used to determine the concentration of HFC–23 by analyzing, on a monthly basis, certified standards with known HFC–23 concentrations that are in the same range (percent levels) as the process samples. This proposed requirement is intended to verify the accuracy and precision of gas chromatographs at the concentrations of interest; calibration at other concentrations does not verify this accuracy with the same level of assurance. The proposed requirement is similar to requirements in protocols for the use of gas chromatography, such as EPA Method 18, *Measurement of Gaseous Organic Compound Emissions by Gas Chromatography.*

(2) Initially verify each weigh scale, flow meter, and combination of volumetric and density measurements used to measure quantities that are to be reported under this rule, and calibrate it thereafter at least every year. We request comment on these proposed requirements.

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[78] Although EPA recognizes that the proposed method for estimating emissions from equipment leaks is rather uncertain, EPA believes that the level of precision is not unreasonable given the small size of the HFC–23 emissions that would be estimated using the method. These emissions are estimated to account for a fraction of a percent of U.S. HFC–23 emissions from this source.

4. Selection of Procedures for Estimating Missing Data

We are proposing that in the cases when an upstream flow meter (i.e., near reactor outlet) is ordinarily used but is not available for some period, the facility can compensate by using downstream production measures (e.g., quantity shipped) and adding 1.5 percent to account for product losses. If HFC–23 concentration measurements are unavailable for some period, we propose that the facility use the average of the concentration measurements from just before and just after the period of missing data.

There is one proposed exception to these requirements: If either method would result in a significant under- or overestimate of the missing parameter (e.g., because the monitoring failure was linked to a process disturbance that is likely to have significantly increased the HFC–23 generation rate), then the facility would be required to develop an alternative estimate of the parameter and explain why and how it developed that estimate.

We request comment on these methods for estimating missing data. We also request comment on the option of estimating missing production data based on consumption of reactants, assuming complete stoichiometric conversion.

5. Selection of Data Reporting Requirements

If you produce HCFC–22 and do not use a thermal oxidizer connected to the HCFC–22 production equipment, you would be required to report the total mass of the HFC–23 generated in metric tons, the mass of any HFC–23 packaged for sale in metric tons, the mass of any HFC–23 sent off site for destruction in metric tons, and the mass of HFC–23 emitted in metric tons. If you produce HCFC–22 and destroy HFC–23 using a thermal oxidizer connected to the HCFC–22 production equipment, you would be required to report the mass of HFC–23 emitted from the thermal oxidizer, the mass of HFC–23 emitted from process vents, and the mass of HFC–23 emitted from equipment leaks, in metric tons.

In addition, if you produce HCFC–22 you would also be required to submit the following supplemental data, as applicable, for QA purposes: Annual HCFC–22 production, annual consumption of reactants (including factors to account for quantities that typically remain unreacted), by reactant, annual mass of materials other than HCFC–22 and HFC–23 (i.e., unreacted reactants, HCl and other byproducts) that are permanently removed from the process, and the method for tracking startups, shutdowns, and malfunctions and HFC–23 generation/emissions during these events. You would also be required to report the names and addresses of facilities to which any HFC–23 was sent for destruction, and the quantities sent to each.

Where HCFC–22 production facilities have estimated missing data, you would be required to report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data. Where the missing data was estimated by a method other than one of those specified, the owner or operator would be required to report why the specified method would lead to a significant under- or overestimate of the parameter(s) and the rationale for the methods used to estimate the missing data.

If you destroy HFC–23, you would be required to report the mass of HFC–23 fed into the thermal oxidizer, the mass of HFC–23 destroyed, and the mass of HFC–23 emitted from the thermal oxidizer. You would also be required to submit the results of your annual HFC–23 concentration measurements at the outlet of the oxidizer. In addition, you would be required to submit a one-time report similar to that required under EPA's stratospheric protection regulations at 40 CFR 82.13(j).

We propose that facilities report these data either because the data are necessary to verify facilities' calculations of HFC–23 generation, emissions, or destruction or because the data allow us to implement other QA checks (e.g., calculation of an HFC–23/HCFC–22 generation factor that can be compared across facilities and over time). We request comment on these proposed reporting requirements.

6. Selection of Records That Must Be Retained

If you produce HCFC–22, you would be required to keep records of the data used to estimate emissions and records documenting the initial and periodic calibration of the gas chromatographs, scales, and flowmeters used to measure the quantities reported under this rule.

If you destroy HFC–23, you would be required to keep records of information documenting your one-time and annual reports.

These records are necessary to enable verification that the GHG emissions monitoring and calculations were performed correctly.

P. Hydrogen Production

1. Definition of the Source Category

Approximately nine million metric tons of hydrogen are produced in the U.S. annually. Hydrogen is used for industrial applications such as petrochemical production, metallurgy, and food processing. Some of the largest users of hydrogen are ammonia production facilities, petroleum refineries, and methanol production facilities.

About 95 percent of all hydrogen produced in the U.S. today is made from natural gas via steam methane reforming. This process consists of two basic chemical reactions: (1) Reformation of the CH_4 feedstock with high temperature steam supplied by burning natural gas to obtain a synthesis gas ($CH_4 + H_2O = CO + 3H_2$); and (2) Using a water-gas shift reaction to form hydrogen and CO_2 from the carbon monoxide produced in the first step ($CO + H_2O = CO_2 + H_22$).

Other processes used for hydrogen production include steam naptha reforming, coal or biomass gasification, partial oxidation of coal or hydrocarbons, autothermal reforming, electrolysis of water, recovery of byproduct hydrogen from electrolytic cells used to produce chlorine and other products, and dissociation of ammonia.

Hydrogen is produced in large quantities at approximately 77 merchant hydrogen production facilities (which produce hydrogen to sell) and 145 captive hydrogen production facilities (which consume hydrogen at the site where it is produced, e.g. petroleum refineries, ammonia, and methanol facilities). Hydrogen is also produced in small quantities at numerous other locations.

National emissions from hydrogen production were estimated to be approximately 60 million metric tons CO_2 (1 percent of U.S. GHG emissions) annually.

The source category covered by the hydrogen production subpart of the proposed rule is merchant hydrogen production. CO_2 emissions from captive hydrogen production facilities at ammonia facilities, petrochemical facilities, and petroleum refineries are covered in proposed 40 CFR part 98, subparts G, X, and Y, respectively.

For additional background information on hydrogen production, please refer to the Hydrogen Production TSD (EPA–HQ–OAR–2008–0508–016).

2. Selection of Reporting Threshold

In developing the threshold for hydrogen production, we considered emissions-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. This threshold is based on combined combustion and process CO_2 emissions at the hydrogen production facility.

In selecting a threshold, we considered emissions data from merchant hydrogen facilities only, which together account for an estimated 15.2 million metric tons CO_2e in 2006.

Table P–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE P–1. THRESHOLD ANALYSIS FOR HYDROGEN PRODUCTION

CO_2 Threshold level (metric tons CO_2e/year)	H_2 Production capacity (tons H_2/year)	Emissions covered		Facilities covered	
		Tons CO_2e/year	Percent	Number	Percent
No threshold	0	15,226,620	100.0	77	100
1,000	116	15,225,220	100.0	73	95
10,000	1,160	15,130,255	99.4	51	66
25,000	2,900	14,984,365	98.4	41	53
100,000	11,600	14,251,265	93.6	30	39

The hydrogen production industry is heterogeneous in terms of the types of facilities. There are some relatively large, emissions intensive facilities, but small facilities are common as well. At a 25,000 ton threshold, although 98.4 percent of emissions would be covered, only 53 percent of facilities would be required to report.

The proposed threshold for reporting emissions from hydrogen production is 25,000 metric tons CO_2e. We are proposing a 25,000 metric tons CO_2e threshold to reduce the compliance burden on small businesses, while still including a majority of GHG emissions from the industry.

For a full discussion of the threshold analysis, please refer to the Hydrogen Production TSD (EPA–HQ–OAR–2008–0508–016). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Several domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from hydrogen production (e.g., the American Petroleum Institute Compendium, the DOE 1605(b), and the CARB Mandatory GHG Emissions Reporting Program). These methods coalesce around variants of two methods for merchant hydrogen production facilities: Direct measurement of CO_2 emissions by CEMS, and the feedstock material balance method.

Option 1. Direct measurement. The CEMS would capture both combustion and process-related CO_2 emissions from a hydrogen facility. Facilities that do not currently employ a CEMS could voluntarily elect to install CEMS for reporting under this subpart. This approach is consistent with DOE's 1605(b) ''A'' rated method and the CARB Mandatory GHG Emissions Reporting Program.

Option 2. Feedstock material balance method. This method accounts for the difference between the quantity and carbon content of all feedstock delivered to the facility and of all products leaving the facility. This approach is consistent with IPCC Tier 3 methods for similar processes (i.e., steam reformation in ammonia production), the DOE 1605(b) ''A'' rated method, and the CARB Mandatory GHG Emissions Reporting Program.

Based on our review of the above approaches, we propose both methods for quantifying GHG emissions from hydrogen production, to be implemented depending on current circumstances at your facility. If you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture combustion- and process-related CO_2 emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related emissions from fuels not captured in the CEMS, as well as CH_4 and N_2O.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS does not measure process emissions, the proposed monitoring method is Option 2. You would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate combustion-related emissions from each hydrogen production unit and any other stationary combustion units. This section of the preamble provides only those procedures for calculating and reporting process-related CO_2 emissions. For CO_2 collected and used onsite or transferred offsite, you must follow the methodology provided in proposed 40 CFR part 98, subpart PP of this part (Suppliers of CO_2).

The feedstock material balance method entails measurements of the quantity and carbon content of all feedstock delivered to the facility and of all products leaving the facility, with the assumption that all the carbon entering the facility in the feedstock that is not captured and sold outside the facility is converted to CO_2 and emitted. The quantity of feedstock consumed must be measured continuously using a flowmeter. The carbon fraction in the feedstock may be provided as part of an ultimate analysis performed by the supplier (*e.g.*, the local gas utility in the case of natural gas feedstock). If the feedstock supplier does not provide the gas composition or ultimate analysis data, the facility would be required to analyze the carbon content of the feedstock on a monthly basis using the appropriate test method in proposed 40 CFR 98.7.

We also considered three other methods for quantifying process-related emissions. The first method requires direct measurement of emissions by CEMS from all reporting facilities. The second method applies a constant proportionality factor, based on the facility's historical data on natural gas consumption, to the facility's hydrogen production rate. The third method we considered applies a national default emission factor to the natural gas consumption rate at a facility.

The first method would generally increase accuracy of reported data. We invite comment on the practicality of adopting the first method. In general, the latter two methods are less certain, as they involve multiplying production and feedstock consumption data by default emission factors based on purity assumptions.

In contrast, the feedstock material balance method is more certain as it involves measuring the consumption and carbon content of the feedstock input. Because 95 percent of hydrogen is produced using steam methane reforming, and the carbon content of natural gas is always within 1 percent of the ratio: One mole of carbon per mole of natural gas, the local utility QA/QC requirements should be more than adequate.

Given the increase in accuracy of the direct measurement and feedstock material balance methods coupled with the minimal additional burden for facilities that already employ CEMS, we propose that facilities utilize the direct measurement method where currently employed, and the feedstock material balance method for all facilities that do not employ CEMS. We have concluded that this requirement does not add additional burden to current practices at the facilities, thereby minimizing costs. The primary additional burden for facilities associated with this method would be in conducting a gas composition analysis of the feedstock on a monthly basis, in cases where this information is not provided by the supplier.

The various approaches to monitoring GHG emissions are elaborated in the Hydrogen Production TSD (EPA–HQ–OAR–2008–0508–016).

4. Selection of Procedures for Estimating Missing Data

Sources using CEMS to comply with this rule would be required to comply with the missing data requirements of proposed 40 CFR part 98, subpart C.

In the event that a facility lacks feedstock supply rates for a certain time period, we propose that facilities use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure. In the event that a monthly value for carbon content is determined to be invalid, an additional sample must be collected and tested. The likelihood for missing data is small, since the fuel meter and carbon content data are needed for financial accounting purposes.

5. Selection of Data Reporting Requirements

We propose that facilities submit their annual CO_2, and N_2O emissions data. Facilities that use CEMS must comply with the procedures specified in proposed 40 CFR 98.36(d)(iv). In addition, we propose that facilities submit the following data on an annual basis for each process unit. These data are needed for us to understand the emissions data and verify the reasonableness of the reported emissions, and are the basis of the feedstock material balance calculation.

The data should include the total quantity of feedstock consumed for hydrogen production, the quantity of CO_2 captured for use and the end use, if known, the monthly analyses of carbon content for each feedstock used in hydrogen production, the annual quantity of hydrogen produced, and the annual ammonia produced, if applicable.

A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and P.

6. Selection of Records That Must Be Retained

We propose that each hydrogen production facility comply with the applicable recordkeeping requirements for stationary combustion units in proposed 40 CFR part 98, subpart C, which are also discussed in Section V.C of this preamble.

Also, we propose that each hydrogen production facility maintain records of feedstock consumption and the method used to determine the quantity of feedstock consumption, QA/QC records (including calibration records and any records required by the QAPP), monthly carbon content analyses, and the method used to determine the carbon content. A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and P. These records consist of values that are directly used to calculate the emissions that are reported and are necessary to enable verification that the GHG emissions monitoring and calculations were done correctly.

Q. Iron and Steel Production

1. Definition of the Source Category

The iron and steel industry in the U.S. is the third largest in the world, accounting for about 8 percent of the world's raw iron and steel production and supplying several industrial sectors, such as construction (building and bridge skeletons and supports), vehicle bodies, appliances, tools, and heavy equipment. In this proposed rule, we are defining the iron and steel production source category to be taconite iron ore processing facilities, integrated iron and steelmaking facilities, electric arc furnace steelmaking facilities that are not located at integrated iron and steel facilities, and cokemaking facilities that are not located at integrated iron and steel facilities. Coke, sinter, and electric arc furnace steel production operations at integrated iron and steel facilities are part of integrated iron and steel facilities. Direct reduced iron furnaces are located at and are part of electric arc furnace steelmaking facilities.

Currently, there are 18 integrated iron and steel steelmaking facilities that make iron from iron ore and coke in a blast furnace and refine the molten iron (and some ferrous scrap) in a basic oxygen furnace to make steel. In addition, there are over 90 electric arc furnace steelmaking facilities that produce steel primarily from recycled ferrous scrap. There are also eight taconite iron ore (pellet) processing facilities, 18 cokemaking facilities, seven of which are co-located at integrated iron and steel facilities, and one direct reduced iron furnace located at an electric arc furnace steelmaking facility.

The primary operation units that emit GHG emissions are blast furnace stoves (24 million metric tons CO_2e/yr), taconite indurating furnaces, basic oxygen furnaces, electric arc furnaces (about 5 million metric tons CO_2e/yr each), coke oven battery combustion stacks (6 million metric tons CO_2e/yr), and sinter plants (3 million metric tons CO_2e/yr). Smaller amounts of GHG emissions are produced by coke pushing (160,000 metric tons CO_2e/yr) and direct reduced iron furnaces (140,000 metric tons CO_2e/yr).

Based on production in 2007, GHG emissions from the source category are estimated at about 85 million metric tons CO_2e/yr or just over 1 percent of total U.S. GHG emissions. Emissions from both process units (47 million metric tons CO_2e/yr) and miscellaneous combustion units (38 million metric tons CO_2e/yr) are significant. Small amounts of N_2O and CH_4 are also emitted during the combustion of different types of fuels.

Although by-product recovery coke batteries and blast furnaces operations produce coke and pig iron, respectively, we are proposing that their emissions be reported as required for combustion units in proposed 40 CFR part 98, subpart C because the majority of their GHG emissions originate from fuel combustion. Emissions from the blast furnace operation occur primarily from the combustion of blast furnace gas and natural gas in the blast furnace stoves. Emissions from by-product recovery coke batteries are generated from the combustion of coke oven gas in the coke battery's underfiring system. In addition to the blast furnace stoves and by-product coke battery underfiring systems, the other combustion units where fuel is the only source of GHG emissions include boilers, process heaters, reheat and annealing furnaces, flares, flame suppression systems, ladle reheaters, and other miscellaneous sources. Emissions from these other combustion sources in 2007 are estimated at 16.8 million metric tons CO_2e/yr for integrated iron and steel facilities, 18.6 million metric tons CO_2e/yr for electric arc furnace steelmaking facilities, and 2.7 million metric tons CO_2e/yr for coke facilities not located at integrated iron and steel facilities. As noted, the proposed requirements for combustion units in proposed 40 CFR part 98, subpart C would apply for estimating the CO_2, CH_4, and N_2O emissions from the following combustion units:

- By-product recovery coke oven battery combustion stacks.
- Blast furnace stoves.
- Boilers.
- Process heaters.
- Reheat furnaces.
- Annealing furnaces.
- Flares.
- Ladle reheaters.
- Other miscellaneous combustion sources.

Emissions from the remaining operation units are generated from the carbon in process inputs and in some cases, from fuel combustion in the process. The process-related CO_2, CH_4 and N_2O emissions from the operation units listed below except for coke pushing would be reported according to the proposed requirements in this section:

- Taconite indurating furnaces.
- Nonrecovery coke oven battery combustion stacks.
- Coke pushing.
- Basic oxygen furnaces.
- Electric arc furnaces.
- Direct reduced iron furnaces.
- Sinter plants.

Emissions from nonrecovery coke batteries do not result from the combustion of a fuel input. In the nonrecovery battery, the volatiles that evolve as the coal is heated are ignited in the crown above the coal mass and in flues used to heat the oven. All of the combustible compounds distilled from the coal are burned, and the exhaust gases containing CO_2 are emitted through the battery's combustion stack. For all types of coke batteries, a small amount of CO_2 is formed when the incandescent coke is pushed from the oven, and prior to quenching with water, some of the coke burns. The CO_2 emissions from taconite plants come primarily from the indurating furnaces where coal and/or natural gas are burned in the pelletizing process, and carbon in the process feed materials (iron ore, limestone, bentonite) is converted to CO_2. The CO_2 emissions from direct reduced iron furnaces result from the combustion of natural gas in the furnace and from the process inputs, primarily from the carbonaceous materials (such as coal or coke) that is mixed with iron ore. During steelmaking in the basic oxygen furnace, most of the GHGs result from blowing oxygen into the molten iron to produce steel by removing carbon, primarily as CO_2. CO_2 emissions also result from the addition of fluxing materials and other process inputs that may contain carbon. Emissions from electric arc furnaces are produced by the same mechanisms as for basic oxygen furnaces, and in addition, the consumption of carbon electrodes during the melting and refining stages contribute to CO_2 emissions.

Emissions of CH_4 and N_2O occur from the combustion of fuels in both combustion units and process units. For fuels that contain CH_4, combustion of CH_4 is not complete, and a small amount of CH_4 is not burned and is emitted. In addition, a small amount of N_2O can be formed as a by-product of combustion from the air (nitrogen and oxygen) that is required for combustion.

Additional background information about GHG emissions from the iron and steel production source category is available in the Iron and Steel Production TSD (EPA–HQ–OAR–2008–0508–017).

2. Selection of Reporting Threshold

In evaluating potential thresholds for iron and steel production, we considered emissions-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 per year. This threshold is based on combined combustion and process CO_2 emissions at an iron and steel production facility.

Table Q–1 of this preamble illustrates that the various thresholds do not have a significant effect on the amount of emissions that would be covered. To avoid placing a reporting burden on the smaller specialty stainless steel producers which may operate as small businesses while still requiring the reporting of GHG emissions from those facilities releasing most of the GHG emissions in this source category, we are proposing a threshold of 25,000 metric tons CO_2e per year for reporting of emissions. This threshold level is consistent with the threshold level being proposed for other source categories with similar facility size characteristics. We are proposing that facilities emitting greater than 25,000 in the iron and steel production source category would be subject to the proposed rule because of the magnitude of their emissions. All integrated iron and steel facilities and taconite facilities exceed the highest emissions threshold considered. Most electric arc furnace facilities (with the possible exception of about 9 facilities) exceed the 25,000 metric tons CO_2e emissions threshold. Requiring facilities that emit 25,000 metric tons CO_2e a year or more to report would capture nearly 100 percent of the emissions without significantly increasing the number of affected facilities.

For a full discussion of the threshold analysis, refer to the Iron and Steel Production TSD (EPA–HQ–OAR–2008–0508–017). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

TABLE Q–1. THRESHOLD ANALYSIS FOR IRON AND STEEL PRODUCTION

Threshold level metric tons CO_2e	Total national emissions (metric tons CO_2e)	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
all in	85,150,877	130	85,150,877	100	130	100
1,000	85,150,877	130	85,150,877	100	130	100
10,000	85,150,877	130	85,141,500	100	128	98
25,000	85,150,877	130	85,013,059	100	121	93

TABLE Q–1. THRESHOLD ANALYSIS FOR IRON AND STEEL PRODUCTION—Continued

Threshold level metric tons CO_2e	Total national emissions (metric tons CO_2e)	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
100,000	85,150,877	130	84,468,696	99.2	111	85

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating emissions from process and combustion sources (e.g. 2006 IPCC Guidelines, U.S. Inventory, the WBCSD/WRI GHG protocol, DOE 1605(b), TCR, EU Emissions Trading System, the American Iron and Steel Institute Protocol, International Iron and Steel Institute Protocol, and Environment Canada's mandatory reporting guidelines). We considered these methodologies for measuring or estimating GHG emissions from the iron and steel source category. The following five options were considered for reporting process-related CO_2 emissions from these sources.

Option 1. Apply a default emission factor based on the type of process and an annual activity rate (e.g. quantity of raw steel, sinter, or direct reduced iron produced). This option is the same as the IPCC Tier 1 approach.

Option 2. Perform a carbon balance of all inputs and outputs using default or typical values for the carbon content of the inputs and outputs. Facility production and other records would be used to determine the annual quantity of process inputs and outputs. CO_2 emissions from the difference of carbon-in minus carbon-out, assuming all is converted to CO_2, would be calculated. This option is the same as the IPCC Tier 2 approach, the WRI default approach, and the DOE 1605(b) approach that is rated ''B.'' It is similar to the approach recommended by American Iron and Steel Institute except that the carbon balance for Option 2 is based on the individual processes rather than the entire plant.

Option 3. Perform a monthly carbon balance of all inputs and outputs using measurements of the carbon content of specific process inputs and process outputs and measure the mass rate of process inputs and process outputs. Calculate CO_2 emissions from the difference of carbon-in minus carbon-out assuming all is converted to CO_2. This is consistent with an IPCC Tier 3 approach (if direct measurements are not available), the WRI/WBCSD preferred approach, the approach used in the EU Emissions Trading System, and the DOE 1605(b) approach that is rated ''A.''

Option 4. Develop a site-specific emission factor based on simultaneous and accurate measurements of CO_2 emissions and production rate or process input rate during representative operating conditions. Multiply the site-specific factor by the annual production rate or appropriate periodic production rate (or process input rate, as appropriate). This approach is included in Environment Canada's methodologies and might be considered a form of direct measurement consistent with the IPCC's Tier 3 approach.

Option 5. Direct and continuous measurement of CO_2 emissions using CEMS for CO_2 concentration and stack gas volumetric flow rate based on the requirements in 40 CFR part 75. This is the IPCC Tier 3 approach (direct measurement).

Proposed option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source. Also, you would use proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O.

If you do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, we propose that Options 3, 4 or 5 could be implemented. You would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. This section of the preamble provides procedures only for calculating and reporting process-related emissions.

We identified Options 3, 4, and 5 as the approaches that have acceptable uncertainty for facility-specific estimates. All of these options would provide insight into different levels of emissions caused by facility-specific differences in feedstock or process operation. Options 3, 4, and 5 are forms of the IPCC's highest tier methodology (Tier 3), therefore, we propose these options as equal options. After consideration of public comments, we may promulgate one or more of the options or a combination based on the additional information that is provided.

We considered but decided against Options 1 and 2 because the use of default values and lack of direct measurements results in a very high level of uncertainty in the emission estimates. These default approaches would not provide site-specific estimates of emissions that would reflect differences in feedstocks, operating conditions, fuel combustion efficiency, variability in fuels and other differences among facilities. In general, we decided against proposing existing 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, and such default approaches are inherently inaccurate for site-specific determinations. 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. According to the IPCC's 2006 guidelines, the uncertainty associated with default emission factors for Options 1 and 2 is ±25 percent, and the uncertainty in the production data used with the default emission factor is ±10 percent, which results in a combined overall uncertainty greater than ±25 percent. If process-specific carbon contents and actual mass rate data for the process inputs and outputs are used (i.e., Option 3) or if direct measurements are used (i.e., Options 4 and 5), the guidelines state that the uncertainty associated with the emission estimates would be reduced.

For Option 3, we are proposing that facilities may estimate process emissions based on a carbon balance that uses facility-specific information on the carbon content of process inputs and outputs and measurements of the mass rate of process inputs and outputs. Monthly determinations of the mass of process inputs and outputs other than fuels would be required. These data are readily available for almost all process inputs and outputs on a monthly basis from purchasing, accounting, and production records that are routinely maintained by each facility. The mass rates of fuels would be measured according to the procedures for fuels in combustion units in proposed 40 CFR part 98, subpart C. The carbon content of each process input and output other than fuels would also be measured each month. A sample would be taken each week, composited for the monthly analysis, and sent to an independent laboratory for analysis of carbon content using the test methods in proposed 40 CFR part 98, subpart A. The carbon content of fuels would be determined using the procedures for fuels in combustion units in proposed 40 CFR part 98, subpart C. The CO_2 emissions would be estimated each month using the carbon balance equations in the proposed rule and then summed to provide the totals for the quarter and for the year.

While this proposed approach is consistent with how iron and steel production facilities are currently developing facility level GHG inventories, there are three components of this approach for which the Agency is requesting comment and supporting information. One issue is the ability to obtain accurate measurements of the process inputs and outputs, especially materials that are bulk solids and molten metal and slag. A second issue is the ability to obtain representative samples of the process inputs and outputs to determine the carbon content, especially for non-homogenous materials such as iron and steel scrap. The third issue is the level of uncertainty in the emission estimates for processes where there is a significant amount of carbon leaving the process with product (such as coke plants). These and other factors may result in an unacceptable level of uncertainty, especially for certain processes, when using the carbon balance approach to estimate emissions.

While we are proposing that emissions from blast furnace stoves and coke battery combustion stacks be reported as would be required for combustion sources under proposed 40 CFR part 98, subpart C, we are also requesting comment on how the carbon balance approach (Option 3) could be implemented as an alternative monitoring option for the entire blast furnace operation and the entire coke plant operation at integrated iron and steel facilities. Comments should address the advantages, disadvantages, types and frequency of measurements that should be required, and whether (and if so, how) the emissions can be determined with reasonable certainty. Comments must demonstrate that the procedures produce results that are reproducible and clearly specify the sampling methods and QA procedures that would ensure accurate results.

For the site-specific emission factor approach (Option 4), the owner or operator may conduct a performance test and determine CO_2 emissions from all exhaust stacks for the process using EPA reference methods to continuously measure the CO_2 concentration and stack gas volumetric flow rate during the test. In addition, either the feed rate of materials into the process or the production rate during the test would be measured. The performance test would be conducted under normal process operating conditions and at a production rate no less than 90 percent of the process rated capacity. For continuous processes (taconite indurating furnaces, non-recovery coke batteries, and sinter plants), the testing would cover at least nine hours of continuous operation. For batch or cyclic processes (basic oxygen furnaces, electric arc furnaces, and direct reduction furnaces), the testing would cover at least nine complete production cycles that start when the furnace is being charged and end after steel or iron and slag have been tapped. We are proposing testing for nine hours or nine production cycles, as applicable, because nine tests should provide a reasonable measure of variability (i.e., the standard deviation for nine production cycles or nine 1-hour runs). If an electric arc furnace is used to produce both carbon steel and low carbon steel (including stainless or specialty steel), separate emission factors would be developed for carbon steel and low carbon steel.

The site-specific emission factor for the process would be calculated in metric tons CO_2 per metric ton of feed or production, as applicable, by dividing the CO_2 emission rate by the feed or production rate. The CO_2 emissions for the process would be calculated by multiplying the emission factor by the total amount of feed or production, as applicable. A new performance test would be required each year to develop a new site-specific emission factor. Whenever there is a significant change in fuel type or mix, change in the process in a manner that affects energy efficiency by more than 10 percent, or a change in the process feed materials in a manner that changes the carbon content of the feed or fuel by more than 10 percent, a new performance test would be conducted and a new site-specific emission factor calculated.

We are also requesting comment on the advantages and disadvantages of Option 4, along with supporting documentation. We have concluded that there may be situations in which the site-specific emission factor approach may result in an uncertainty lower than that associated with the carbon balance approach and provide more reasonable emission estimates. An example is nonrecovery coke plants, where a carbon balance approach may result in an unacceptably high level of uncertainty from subtracting two very large numbers (carbon in with coal and carbon out with coke) to estimate emissions that could instead be accurately and directly measured at the combustion stack.

The primary sources of variability that affect CO_2 emissions from process sources in general are the carbon content of the process inputs and fuel and any changes to the process that alter energy efficiency. For most processes, the carbon content of process inputs and fuels is consistent and stable, and if a process change alters energy efficiency, a re-test could be performed to develop a new emission factor that reflected the change. We are requesting comment and supporting information on the minimum time or number of production cycles needed for testing to develop a representative emission factor, and how often periodic re-testing should be required (e.g., annually, quarterly, or only when there is a process change). We are also requesting that any comments on Option 4 address how changes in process inputs, fuels, or process energy efficiency should be accounted for, such as requiring a re-test if the carbon content of inputs change by more than some specified percent, if the type or mix of fuel is changed, or if there is a significant change in fuel consumption due to a process change.

We are also proposing that you may use direct measurements, noting that CEMS (Option 5) provide the lowest uncertainty of the three options. This approach overcomes many of the limitations associated with other options considered such as accounting for the variability in emissions due to changes in the process, feed materials, or fuel over time. It would be applied to stacks that are already equipped with sampling ports and access platforms; consequently, it is technically feasible and cost effective. For those emission sources already equipped with CEMS, we are proposing that they be modified (if necessary) and used to determine CO_2 emissions for that emission source. We are proposing this requirement because it provides direct emission measurements that have low uncertainty with only a minimal additional cost burden. We also request comment, along with supporting documentation, on the advantages and disadvantages of Option 5.

We are also proposing that CH_4 and N_2O emissions from the combustion of fuels in both combustion units and process units be determined and reported. All of the fuels used at iron and steel production processes are included in the methodologies in proposed 40 CFR part 98, subpart C for N_2O and CH_4. Consequently, EPA is proposing to use the same methodology as in proposed 40 CFR part 98, subpart C for determining and reporting emissions of N_2O and CH_4 from both stationary combustion units and process units.

Miscellaneous Emissions Sources. Emissions may also occur when the incandescent coke is pushed from the coke oven and transported to the quench tower where it is cooled (quenched) with water. A small portion of the coke burns during this process prior to quenching. We updated the coke oven section of the AP–42[79] compilation of emission factors in May 2008, and the update included an emission factor for CO_2 emissions developed from 26 tests for particulate matter from pushing operations. The emissions factor (0.008 metric tons CO_2e per metric ton of coal charged) was derived to account for emissions from the pushing emission control device and those escaping the capture system. We are proposing that coke facilities use the AP–42 emission factor to estimate CO_2 emissions from coke pushing operations.

There are dozens of emission points and various types of fugitive emissions, not collected for emission through a stack, from the production processes and materials handling and transfer activities at integrated iron and steel facilities. These emissions from iron and steel plants have been of environmental interest primarily because of the particulate matter in the emissions. Examples include ladle metallurgy operations, desulfurization, hot metal transfer, sinter coolers, and the charging and tapping of furnaces. The information we have examined to date indicates that these emissions contribute very little to the overall GHG emissions from the iron and steel sector (probably on the order of one percent or less). For example, emissions of blast furnace gas may be emitted during infrequent process upsets (called ''slips'') when gas is vented for a short period or from leaks in the ductwork that handles the gas. However, the mass of GHG emissions is expected to be small because most of the carbon in blast furnace gas is from carbon monoxide, which is not a GHG. Fugitive emissions and emissions from control device stacks may also occur from blast furnace tapping, the charging and tapping of basic oxygen furnaces and electric arc furnaces, ladle metallurgy, desulfurization, etc. However, we have no information that indicates CO_2 is generated from these operations, and a review of test reports from systems that capture these emissions show that CO_2 concentrations are very low (at ambient air levels). Fugitive emissions containing CH_4 may occur from leaks of raw coke oven gas from the coke oven battery during the coking cycle. However, the mass of these emissions is expected to be small based on the small number of leaks that are now allowed under existing Federal and State standards that regulate these emissions. In addition, since these emissions are not captured in a conveyance, there is no practical way to measure them. Consequently, we are not proposing that fugitive emissions be reported because we believe their GHG content is negligible and because there is no practical way of measuring them. However, we welcome public comment, along with supporting data and documentation, on whether fugitive emissions should be included, and if so, how these emissions can be estimated.

4. Selection of Procedures for Estimating Missing Data

For process sources that use Option 3 (carbon balance) or Option 4 (site-specific emission factor), no missing data procedures would apply because 100 percent data availability would be required. For process sources that use Option 5 (direct measurement by CEMS), the missing data procedures would be the same as for units using Tier 4 in the general stationary fuel combustion source category in proposed 40 CFR part 98, subpart C.

5. Selection of Data Reporting Requirements

We are proposing that facilities submit annual emission estimates for CO_2 presented by calendar quarters for coke oven battery combustion stacks, coke pushing, blast furnace stoves, taconite indurating furnaces, electric arc furnaces, argon-oxygen decarburization vessel, direct reduced iron furnaces, and sinter plants.

In addition we propose that facilities submit the following data to assist in checks for reasonableness and for other data quality considerations: Total mass for all process inputs and outputs when the carbon balance is used for specific processes by calendar quarters, site-specific emission factor for all processes for which the site-specific emission factor approach is used, annual production quantity for taconite pellets, coke, sinter, iron, raw steel by calendar quarters, annual production capacity for taconite pellets, coke, sinter, iron, raw steel, annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces, and the quantity of CO_2 captured for use and the end use, if known.

A full list of data that would be reported is included in proposed 40 CFR part 98, subparts A and Q.

6. Selection of Records That Must Be Retained

In addition to the recordkeeping requirements for general stationary fuel combustion sources, we propose that the following additional records be kept to assist in QA/QC and verification purposes: GHG emission estimates from the iron and steel production process by calendar quarter, monthly total for all process inputs and outputs when the carbon balance is used for specific processes, documentation of calculation of site-specific emission factor for all processes for which the site-specific emission factor approach is used, monthly analyses of carbon content, and monthly production quantity for taconite pellets, coke, sinter, iron, and raw steel.

R. Lead Production

1. Definition of the Source Category

Lead is a metal used to produce various products such as batteries, ammunition, construction materials, electrical components and accessories, and vehicle parts. For this proposed rule, we are defining the lead production source category to consist of primary lead smelters and secondary lead smelters. A primary lead smelter produces lead metal from lead sulfide ore concentrates through the use of pyrometallurgical processes. A secondary lead smelter produces lead and lead alloys from lead-bearing scrap metal.

For the primary lead smelting process used in the U.S., lead sulfide ore concentrate is first fed to a sintering process to burn sulfur from the lead ore. The sinter is smelted with a

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[79] See Compilation of Air Pollutant Emission Factors, Fifth Edition: *http://www.epa.gov/ttn/chief/ap42/ch12/final/c12s02_may08.pdf.*

carbonaceous reducing agent in a blast furnace to produce molten lead bullion. From the furnace, the bullion is transferred to dross kettle furnaces to remove primarily copper and other metal impurities. Following further refining steps, the lead is cast into ingots or alloy products.

The predominate feed materials processed at U.S. secondary lead smelters are used automobile batteries, but these smelters can also process other lead-bearing scrap materials including wheel balance weights, pipe, solder, drosses, and lead sheathing. These incoming lead scrap materials are first pre-treated to partially remove metal and nonmetal contaminants. The resulting lead scrap is smelted (U.S. secondary lead smelters typically use either a blast furnace or reverberatory furnace). The molten lead from the smelting furnace is refined in kettle furnaces, and then cast into ingots or alloy products.

Lead production results in both combustion and process-related GHG emissions. Combustion-related CO_2, CH_4, and N_2O emissions are generated from metallurgical process equipment used at primary and secondary lead smelters when natural gas or another fuel is burned in the unit to produce heat for drying, roasting, sintering, calcining, melting, or casting operations. Process-related CO_2 emissions are released from the lead smelting process due to the addition of a carbonaceous reducing agent such as metallurgical coke or coal to the smelting furnace. The reduction of lead oxide to lead metal during the process produces the CO_2 emissions.

Currently there is one primary lead smelter operating in the U.S. There are 26 secondary lead smelters in the U.S. with widely varying annual lead production capacities ranging from approximately 1,000 metric tons to more than 100,000 metric tons. Total national GHG emissions from lead production in the U.S. were estimated to be approximately 0.9 million metric tons CO_2e in 2006. These emissions include both on-site stationary combustion emissions (CO_2, CH_4, and N_2O) and process-related emissions (CO_2). The majority of these emissions were from the combustion of carbon-based fuels. Combustion GHG emissions were 0.6 million metric tons CO_2e emissions (69 percent of the total emissions). The remaining 0.3 million metric tons CO_2e (31 percent of the total emissions) were process-related GHG emissions.

Additional background information about GHG emissions from the lead production source category is available in the Lead Production TSD (EPA–HQ–OAR–2008–0508–018).

2. Selection of Reporting Threshold

In developing the threshold for lead production facilities, we considered using annual GHG emissions-based threshold levels 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. This threshold is based on combined combustion and process CO_2 emissions at the lead production facility. Table R–1 of this preamble presents the estimated emissions and number of facilities that would be subject to GHG emissions reporting, based on existing facility lead production capacities, under these various threshold levels.

TABLE R–1. THRESHOLD ANALYSIS FOR LEAD SMELTERS

Threshold level metric tons CO_2e/yr	Total nationwide emissions	Nationwide number of facilities	Emissions covered		Facilities covered	
			metric tons CO_2e/yr	Percent	Facility number	Percent
1,000	866,000	27	859,000	99	17	63
10,000	866,000	27	853,000	98	16	59
25,000	866,000	27	798,000	92	13	48
100,000	866,000	27	0	0	0	0

Secondary lead smelters in the U.S. vary greatly in production capacity and include 10 small facilities with production capacities less than 4,000 tons per year. Table R–1 of this preamble shows approximately 92 percent of the GHG emissions that result from lead production are released from the one primary smelter and 12 secondary smelters that emit more than 25,000 metric tons CO_2e annually. Of the facilities with annual GHG emissions below 25,000 metric tons CO_2e, 10 secondary smelters are estimated to emit less than 1,000 metric tons CO_2e annually.

To avoid placing a reporting burden on the smaller secondary lead smelters which may operate as small businesses while still requiring the reporting of GHG emissions from those facilities releasing most of the GHG emissions in this source category, we are proposing a threshold of 25,000 metric tons CO_2e per year for reporting of emissions. This threshold level is consistent with the threshold level being proposed for other source categories with similar facility size characteristics. More discussion of the threshold selection analysis is available in the Lead Production TSD (EPA–HQ–OAR–2008–0508–018). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We reviewed existing domestic and international GHG monitoring guidelines and protocols including the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, U.S. GHG Inventory, the EU Emissions Trading System, the Canadian Mandatory Greenhouse Gas Reporting Program, and the Australian National Greenhouse Gas Reporting Program. These methods coalesce around the following four options for estimating process-related CO_2 emissions from lead production facilities. A full summary of methods reviewed is available in the Lead Production TSD (EPA–HQ–OAR–2008–0508–018).

Option 1. Apply a default emission factor for the process-related emissions to the facility's lead production rate. This is a simplified emission calculation method using only default emission factors to estimate process-related CO_2 emissions. The method requires multiplying the amount of lead produced by the appropriate default emission factors from the 2006 IPCC Guidelines. This method is consistent with the IPCC Tier 1 method.

Option 2. Perform monthly measurements of the carbon content of specific process inputs and measure the mass rate of these inputs. This is the IPCC Tier 3 approach and the higher order methods in the Canadian and Australian reporting programs. Implementation of this method requires owners and operators of affected lead smelters to determine the carbon contents of materials added to the smelting furnace by analysis of representative samples collected of the material or from information provided by the material suppliers. In addition, you must measure and record the quantities of these input materials consumed during production. To obtain the process-related CO_2 emission estimate, the material carbon content would be multiplied by the corresponding mass of the carbon-containing input material consumed and a conversion factor of carbon to CO_2. This method assumes that all of the carbon is converted to CO_2 during the reduction process. The facility owner or operator would determine the average carbon content of the material for each calendar month using information provided by the material supplier or by collecting a composite sample of material and sending it to an independent laboratory for chemical analysis.

Option 3. Use CO_2 emissions data from a stack test performed using EPA reference test methods to develop a site-specific process emissions factor which is then applied to quantity measurement data of feed material or product for the specified reporting period. This monitoring method is applicable to furnace configurations for which the GHG emissions are contained within a stack or vent. Using site-specific emissions factors based on short-term stack testing is appropriate for those facilities where process inputs (*e.g.*, feed materials, carbonaceous reducing agents) and process operating parameters remain relatively consistent over time.

Option 4. Use direct emission measurement of CO_2 emissions. For furnace configurations in which the process off-gases are contained within a stack or vent, direct measurement of the CO_2 emissions can be made by continuously measuring the off-gas stream CO_2 concentration and flow rate using a CEMS. For a smelting furnace used for lead production where both combustion and process-related emissions are released by a source (*e.g.* blast furnace) emissions reported by using a CEMS would be total CO_2 emissions including both combustion and process-related CO_2 emissions.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where CEMS would not adequately account for combustion and process related CO_2 emissions, the proposed monitoring method for process-related CO_2 from lead production is Option 2. You would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. This section of the preamble provides procedures only for calculating and reporting process-related emissions.

We propose Option 2, due to the operating variations between the individual U.S. lead production facilities, including differences in equipment configurations, mix of lead feedstocks charged, and types of carbon materials used. Further, Option 2 would result in lower uncertainty as compared to applying a default emissions factor based approach to these units.

Although we are not proposing to require you to directly measure process emissions, unless you meet the requirements of proposed 40 CFR part 98, subpart C and the CEMS account for both combustion and process-relate emissions, you could opt to use direct measurement of CO_2 emissions as an alternative GHG emissions estimation method because it would best reflect actual operating practices at your facility, and therefore, reduce uncertainty. While we recognize that the costs for conducting direct measurements may be higher than other methods, we are proposing to include this alternative because it provides GHG emissions data that have low uncertainty. The additional cost burden may be acceptable to owners and operators with site-specific reasons for choosing this alternative.

We decided not to propose the use of the default CO_2 emission factors (Option 1) because their application is more appropriate for GHG estimates from aggregated process information on a sector-wide or nationwide basis than for determining GHG emissions from specific facilities. We considered the additional burden of the material measurements required for the carbon calculations under Option 2 small in relation to the increased accuracy expected from using this site-specific information to calculate the process-related CO_2 emissions.

We also decided not to propose Option 3 because of the potential for significant variations at lead smelters in the characteristics and quantities of the furnace inputs (e.g., lead scrap materials, carbonaceous reducing agents) and process operating parameters. A method using periodic, short-term stack testing would not be practical or appropriate for those lead smelters where the furnace inputs and operating parameters do not remain relatively consistent over the reporting period.

Further details about the selection of the monitoring methods for GHG emissions is available in the Lead Production TSD (EPA–HQ–OAR–2008–0508–018).

4. Selection of Procedures for Estimating Missing Data

For smelting furnaces for which the owner or operator calculates process GHG emissions using site-specific carbonaceous input material data, the proposed rule requires the use of substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable, or ''missing.'' If the carbon content analysis of carbon inputs is missing or lost the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. In those cases when an owner or operator uses direct measurement by a CO_2 CEMS, the missing data procedures would be the same as the Tier 4 requirements described for general stationary fuel combustion sources in proposed 40 CFR part 98, subpart C. The likelihood for missing data is low, as businesses closely track their purchase of production inputs.

5. Selection of Data Reporting Requirements

The proposed rule would require annual reporting of the total annual CO_2 process-related emissions from each smelting furnace at lead production facilities, as well as any stationary fuel combustion emissions. In addition, we are proposing that additional information that forms the basis of the emissions estimates also be reported so that we can understand and verify the reported emissions. This addition information includes the total number of smelting furnaces operated at the facility, the facility lead product production capacity, the annual facility production quantity, annual quantity and type of carbon-containing input materials consumed or used, annual weighted average carbon contents by material type, and the number of facility operating hours in the calendar year. A complete list of data to be reported is included in proposed 40 CFR part 98, subparts A and R.

6. Selection of Records That Must Be Retained

Maintaining records of the information used to determine the reported GHG emissions is necessary to enable us to verify that the GHG emissions monitoring and calculations were done correctly. In addition to the information reported as described in Section V.R.5 of this preamble, we propose that all facilities estimating emissions according to the carbon input method maintain records of each carbon-containing input material consumed or used (other than fuel) the monthly material quantity, monthly average carbon content determined for material, and records of the supplier provided information or analyses used for the determination. If you use the CEMS procedure, you would maintain the CEMS measurement records according to the procedures in proposed 40 CFR part 98, subpart C. These records would be required to be maintained onsite for 5 years. A complete list of records to be retained is included in the proposed rule.

S. Lime Manufacturing

1. Definition of the Source Category

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Its major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. Lime is used for the following purposes: Metallurgical uses (36 percent), environmental uses (29 percent), chemical and industrial uses (21 percent), construction uses (13 percent), and to make dolomite refractories (1 percent).

For U.S. operations, the term ''lime'' actually refers to a variety of chemical compounds. These compounds include calcium oxide (CaO), or high-calcium quicklime; calcium hydroxide ($Ca(OH)_2$), or hydrated lime; dolomitic quicklime ($(CaO \bullet MgO)$); and dolomitic hydrate ($(Ca(OH)_2 \bullet MgO)$ or $(Ca(OH)_2 \bullet Mg(OH)_2)$). Lime manufacturing involves three main processes: Stone preparation, calcination, and hydration. During the calcination process, the carbonate in limestone is sufficiently heated and reduced to CO_2 gas. In certain applications, lime reabsorbs CO_2 during use thereby reducing onsite GHG emissions.

National emissions from the lime industry were estimated to be 25.4 million metric tons CO_2e in 2004 (or <0.4 percent of national emissions). These emissions include both process-related emissions and on-site stationary combustion emissions from 89 lime manufacturing facilities across the U.S. and Puerto Rico. Process-related emissions account for 14.3 million metric tons CO_2e, or 56 percent of the total, while on-site stationary combustion emissions account for the remaining 11.1 million metric tons CO_2e.

For additional background information on lime manufacturing, please refer to the Lime Manufacturing TSD (EPA–HQ–OAR–2008–0508–019).

2. Selection of Reporting Threshold

In developing the proposed reporting threshold for the lime manufacturing source category, we considered emissions-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. This threshold is based on combined combustion and process CO_2 emissions at a lime production facility. Table S–1 of this preamble illustrates the emissions and facilities that would be covered under various thresholds.

TABLE S–1. THRESHOLD ANALYSIS FOR LIME MANUFACTURING

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			metric tons CO_2e/yr	Percent	Number	Percent
1,000	25,421,043	89	25,421,043	100	89	100
10,000	25,421,043	89	25,396,036	99.9	86	97
25,000	25,421,043	89	25,371,254	99.8	85	96
100,000	25,421,043	89	23,833,273	94	52	58

The lime manufacturing sector consists primarily of large facilities and a few smaller facilities. All facilities, except four, exceed the 25,000 metric tons CO_2e threshold.

Consistent with National Lime Association recommendations, and in order to simplify the proposed rule and avoid the need to calculate and report whether the threshold value has been exceeded, we are proposing that all lime manufacturing facilities report GHG emissions. This captures 100 percent of emissions without significantly increasing the number of facilities that would have reported at 1,000, 10,000, or 25,000 metric ton thresholds. For a full discussion of the threshold analysis, please refer to the Lime Manufacturing TSD (EPA–HQ–OAR–2008–0508–019). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from lime manufacturing (*e.g.*, the 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), National Lime Association CO_2 Protocol, and the EU Emissions Trading System). These methodologies can be summarized by the following two overall approaches to estimating emissions, based on measuring either the carbonate inputs to the kiln or production outputs of the lime manufacturing process.

Input-based Options. We considered the IPCC Tier 3 method which requires facilities to estimate process emissions by measuring the quantity of carbonate inputs to the kiln(s) and applying the appropriate emission factors and calcination fractions to the carbonates consumed. In order to assess the composition of carbonate inputs, facilities would send samples of their inputs and lime kiln dust produced to an off-site laboratory for analysis on a monthly basis using ASTM C25–06, ''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'' (incorporated by reference, see proposed 40 CFR 98.7). For greater accuracy, facilities would also estimate the calcination fraction of each carbonate consumed on a monthly basis. However, it is generally accepted that the calcination fraction of carbonates during lime production is 100 percent or very close to it.

Output-based Options. We also considered three output-based methods for quantifying process-related emissions based on the quantity of lime produced. IPCC's Tier 1 method applies default emission factors to each of the three types of lime produced (high calcium lime, dolomitic lime, or hydraulic lime). The IPCC Tier 2 method applies a default emissions factor based on lime type to the corresponding quantity of all lime produced (by type), correcting for the amount of calcined byproduct/waste product (such as lime kiln dust) produced in the process.

The third output method, developed by the National Lime Association, improves upon the IPCC Tier 2 procedure. In this method, facilities multiply the amount of lime produced at each kiln and the amount of calcined byproducts/wastes at the kiln by an emission factor. The emission factor is derived based on facility specific chemical analysis of the CaO and magnesium oxide (MgO) content of the lime produced at the kiln. To assess the composition of the lime and calcined byproduct/waste product, facilities would send samples to an off-site laboratory for analysis on a monthly basis following the procedures described in the National Lime Association's method protocol, along with the procedures in ASTM C25–06, ''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'' (incorporated by reference, see proposed 40 CFR 98.7). This third output approach is also consistent with 1605(b)'s ''A'' rated approach and EU Emission Trading System's calculation B method.

We compared the various methods for estimating process-related CO_2 emissions. In general, the IPCC output methods are less certain, as they involve multiplying production data by emission and correction factors for lime kiln dust that are likely default values based on purity assumptions (i.e. the total CaO and MgO content of the lime products). In contrast, the input method is more certain as it involves measuring the consumption of each carbonate input and calculating purity fractions. According to the 2006 IPCC Guidelines, the uncertainty involved in the carbonate input approach for the IPCC Tier 3 method is 1 to 3 percent and the uncertainty involved in using the default emission factor and lime kiln dust correction factor for the Tier 1 and Tier 2 production-based approaches is 15 percent. However, IPCC states that the major source of uncertainty in the above approaches is the CaO content of the lime produced.

Proposed Option. Under this proposed rule, if you are using an existing CEMS that meets the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate both combustion and process CO_2 emissions. Also, you would refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

Under this proposed rule, if you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C, you would use the National Lime Association method in this section of the preamble to calculate process-related CO_2 emissions. Refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

We are proposing the National Lime Association's output-based procedure because this method is already in use by U.S. facilities and the improvement in accuracy compared to default approaches can be achieved at minimal additional cost. The measurement of production quantities is common practice in the industry and is usually measured through the use of scales or weigh belts so additional costs to the industry are not anticipated. The primary additional burden for facilities would include conducting a CaO and MgO analysis of each lime product on a monthly basis (to be averaged on an annual basis). However, approximately two thirds of the lime manufacturing facilities in the U.S. are already undertaking sampling efforts to meet reporting goals set forth by the National Lime Association.

We request comment on the advantages and disadvantages of the IPCC Tier 3 method and supporting documentation. After consideration of public comments, we may promulgate the IPCC Tier 3 input-based procedure, the National Lime Association output-based procedure, or a combination based on additional information that is provided.

The various approaches to monitoring GHG emissions are elaborated in the Lime Manufacturing TSD (EPA–HQ–OAR–2008–0508–019).

4. Selection of Procedures for Estimating Missing Data

It is assumed that a facility would be able to supply facility-specific production data. Since the likelihood for missing data is low because businesses closely track production, 100 percent data availability is required for lime production (by type) in the proposed rule. If analysis for the CaO and MgO content of the lime product are unavailable or ''missing'', facility owners or operators would substitute a data value that is the average of the quality-assured values of the parameter immediately before and immediately after the missing data period.

5. Selection of Data Reporting Requirements

We propose that in addition to stationary fuel combustion GHG emissions, you report annual CO_2 emissions for each kiln. In addition, for each kiln we are proposing that facilities report the following data used as the basis of the calculations to assist in verification of estimates, checks for reasonableness, and other data quality considerations for process emissions: Annual lime production and production capacity, emission factor by lime type, and number of operating hours in the calendar year. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and S.

6. Selection of Records That Must be Retained

Maintaining records of the information used to determine the reported GHG emissions are necessary to enable us to verify that the GHG emissions monitoring and calculations were done correctly. In addition to the data to be reported, we are proposing that the facilities maintain records of the calculation of emission factors, results of the monthly chemical composition analyses, total lime production for each kiln by month and type, total annual calcined byproducts/wastes produced by each kiln averaged from monthly data, and correction factor for byproducts/waste products for each kiln. A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and S.

T. Magnesium Production

1. Definition of the Source Category

Magnesium is a high-strength and light-weight metal that is important for the manufacture of a wide range of products and materials, such as portable electronics, automobiles, and other machinery. The U.S. accounts for less than 10 percent of world primary magnesium production but is a significant importer of magnesium and producer of cast parts. The production and processing of magnesium metal under common practice results in emissions of SF_6. For further information, see the Magnesium Production TSD (EPA–HQ–OAR–2008–0508–020).

The magnesium metal production (primary and secondary) and casting industry typically uses SF_6 as a cover gas to prevent the rapid oxidation and burning of molten magnesium in the presence of air. A dilute gaseous mixture of SF_6 with dry air and/or CO_2 is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF_6 reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF_6 reacting in magnesium production and processing is under study but is presently assumed to be negligible. Thus, all SF_6 used is presently assumed to be emitted into the atmosphere.

Cover gas systems are typically used to protect the surface of a crucible of molten magnesium that is the source for a casting operation and to protect the casting operation itself (e.g., ingot casting). SF_6 has been used in this application in most parts of the world for the last twenty years. Due to increasing awareness of the GWP of SF_6, the magnesium industry has begun exploring climate-friendly alternative melt protection technologies. At this time the leading alternatives include HFC–134a, a fluorinated ketone (FK 5–1–12, $C_3F_7C(O)C_2F_5$), and dilute sulfur dioxide (SO_2). The application of the fluorinated alternatives mentioned here may generate byproduct emissions of concern including PFCs. We are proposing that magnesium production and processing facilities report process emissions of SF_6, HFC–134a, FK 5–1–12, and CO_2.

Total U.S. emissions of SF_6 from magnesium production and processing in the U.S. were estimated to be 3.2 metric tons CO_2e in 2006. Primary and secondary production activities at 3 facilities accounted for about 64 percent of total emissions, or 2 metric tons CO_2e. Approximately 20 magnesium die casting facilities in the U.S. accounted for more than 30 percent, or more than 0.9 metric tons CO_2e of total magnesium-related SF_6 emissions. Other smaller casting activities such as sand and permanent mold casting accounted for the remaining magnesium-related emissions of SF_6. The term ''metal processed'' used here is defined as the mass of magnesium melted to cast or create parts. This should not be confused with the mass of finished magnesium parts because varying amounts of the metal may be lost as scrap when performing casting operations.

2. Selection of Reporting Threshold

We considered emissions 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 as well as capacity based thresholds as shown in Tables T–1 and T–2 of this preamble.

TABLE T–1. THRESHOLD ANALYSIS FOR MG PRODUCTION BASED ON EMISSIONS

Threshold level metric tons CO_2e/yr	Total nationwide emissions metric tons CO_2e/Yr	Nationwide number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
1,000	3,200,000	13	2,954,559	92	13	100
10,000	3,200,000	13	2,939,741	92	11	85
25,000	3,200,000	13	2,939,741	92	11	85
100,000	3,200,000	13	2,872,982	90	9	69

We believe that there are additional facilities than the 13 listed above, however, we do not have sufficient information to estimate emissions or production levels.

TABLE T–2. THRESHOLD ANALYSIS FOR MG PRODUCTION BASED ON MG PRODUCTION CAPACITY

Capacity threshold level Mg/yr	Total nationwide emissions metric tons CO_2e/Yr	Number of facilities	Emissions covered		Facilities Covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
26	3,200,000	13	2,954,559	92	13	100
262	3,200,000	13	2,949,732	92	12	92
656	3,200,000	13	2,949,732	92	12	92
2,622	3,200,000	13	2,780,717	87	9	69

We believe that there are additional facilities than the 13 listed above, however, we do not have sufficient information to estimate emissions or production levels.

Under the proposed rule, magnesium metal production and parts casting facilities would have to report their total GHG emissions if those emissions exceeded 25,000 metric tons CO_2e. This threshold covers all currently identified operating U.S. primary and secondary magnesium producers and most die casters, accounting for over 99 percent of emissions from these source categories.

The proposed emissions threshold of 25,000 metric tons CO_2e is equal to emissions of 1,046 kg of SF_6; 19,231 kg of HFC–134a; or 25,000,000 kg of CO_2 or FK 5–1–2. Other emission threshold options that we considered were 1,000 metric tons CO_2e, 10,000 metric tons CO_2e, and 100,000 metric tons CO_2e. The 10,000 metric tons CO_2e emission threshold yielded results identical to those of the proposed option.

We also considered capacity-based thresholds of 26, 262, 656, and 2,622 metric tons, based on 100 percent capacity utilization and an SF_6 emission rate of 1.6 kg SF_6 per metric ton of magnesium produced or processed. This emission factor represents the sum of (1) the average of the emission factors reported for secondary production and die casting through our magnesium Partnership (excluding outliers), and (2) the standard deviation of those emission factors. The 1.6 kg-per-ton factor is higher than most, though not all, of the emission factors reported, which ranged from 0.7 to 7 kg/ton Mg in 2006. The resulting capacity thresholds yielded results very similar to those of the emission-based thresholds.

The emissions based threshold was selected over the capacity based threshold for several reasons. The emissions based threshold is simple to evaluate because magnesium production and processing facilities can use readily available data regarding consumption of SF_6 and would also possess similar data for alternatives such as HFC–134a as these are phased-in over time. To determine whether they exceeded the thresholds, magnesium facilities would multiply the total consumption of each of these gases by a GWP-unit conversion factor that could be compared to the 25,000 metric ton threshold. The equation for this calculation is provided in the proposed regulatory text.

The emissions-based threshold of 25,000 metric tons CO_2e also takes into account the variability in cover gas identities, usage rates, and process conditions. Alternatives to SF_6 have considerably lower GWPs than SF_6. In facilities where SF_6 is used, the usage rate can vary by an order of magnitude depending on the casting process and operating conditions. Therefore, cover gas emissions are not well predicted by production capacity. Because emissions of each cover gas are assumed to equal use, and facilities are expected to track gas use in the ordinary course of business, facilities should have little difficulty determining whether or not they must report under this rule. For a full discussion of the threshold analysis, please refer to the Magnesium Production TSD (EPA–HQ–OAR–2008–0508–020). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We reviewed a wide range of protocols and guidance in developing this proposal, including the 2006 IPCC Guidelines, EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry, the U.S. GHG Inventory, DOE 1605(b), EPA's Climate Leaders Program, and TCR.

The methods described in these protocols and guidance were similar to the methods described by the IPCC Guidelines and the U.S. GHG Inventory methodology. These methods range from a Tier 1 approach, based on default consumption factors per unit Mg produced or processed, to a Tier 3 approach based on facility-specific measured emissions data.

Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, you would be required to follow the proposed monitoring method discussed below. The proposed method outlined below accounts for process-related SF_6, HFC–134a, FK 5–1–12, and CO_2 emissions. Refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

The proposed method for monitoring SF_6, HFC–134a, FK 5–1–12, and CO_2 cover gas emissions from magnesium production and processing is similar to the Tier 2 approach in the 2006 IPCC Guidelines for magnesium production. This approach is based on facility-specific information on cover gas consumption and assumes that all gases consumed are emitted. This methodology applies to any cover gas that is a GHG, including SF_6, CO_2, HFC–134a and FK 5–1–12.

We propose three options for measuring gas consumption:

1. Weighing gas cylinders as they are brought into and out of service allowing a facility to accurately track the actual mass of gas used.
2. Using a mass flow meter to continuously measure the mass of global warming gases used.
3. Performing a facility level mass balance for all global warming gases used at least once annually. Using this approach, a facility would review its gas purchase records and inventory to determine actual mass of gas used and subtract a 10 percent default heel factor to account for residual gas in cylinders returned to the gas suppliers.

When weighing cylinders to determine cover gas consumption, facilities would weigh all gas cylinders that are returned to the gas supplier, or have the gas supplier weigh the cylinders, to determine the residual gas still in the cylinder. The weight of residual gas would be subtracted from the weight of gas delivered to determine gas consumption. Gas suppliers can provide detailed monthly spreadsheets with exact residual gas amounts returned.

Facilities would be required to follow several procedures to ensure the quality of the consumption data. These procedures could be readily adopted, or would be based on information that is already collected for other reasons. Facilities would be required to track specific cylinders leaving and entering storage with check-out and weigh-in sheets and procedures. Scales used for weighing cylinders and mass flow meters would need to be accurate to within 1 percent of true mass, and would be periodically calibrated. Facilities would calculate the facility usage rate, compare it to known default emission rates and historical data for the facility, and investigate any anomalies in the facility usage rate. Finally, facilities would need to have procedures to ensure that all production lines have provided information to the manager compiling the emissions report, if this is not already handled through an electronic inventory system.

We are not proposing IPCC's Tier 1 or 3 methodologies for calculating emissions. Although the Tier 1 methodology is straightforward, the default consumption factor for the SF_6 usage rate is significantly uncertain due to the variability in production processes and operating conditions. The Tier 3 methodology of conducting facility-specific measurements of emissions to account for potential cover gas destruction and byproduct formation is the most accurate, but also poses significant economic challenges for implementation because of the cost of direct emission measurements.

4. Selection of Procedures for Estimating Missing Data

In general, it is unlikely that cover gas consumption data would be missing. Facilities are expected to know the quantities of cover gas that they consume because facility operations rely on accurate monitoring and tracking of costs. Facilities would possess invoices from gas suppliers during a given year and many facilities currently track the weight of SF_6 consumed by weighing individual cylinders prior to replacement.

However, where cover gas consumption information is missing, we propose that facilities estimate emissions by multiplying production by the average cover gas usage rate (kg gas per ton of magnesium produced or processed) from the most recent period when operating conditions were similar to those for the period for which the data are missing, i.e., using the same cover gas concentrations and flow rates and, if applicable, casting parts of a similar size.

5. Selection of Data Reporting Requirements

Facilities would be required to report total facility GHG emissions and emissions by process type: Primary production, secondary production, die casting, or other type of casting. For total facility and process emissions, emissions would be reported in metric tons of SF_6, HFC–134a, FK 5–1–12, and CO_2 (used as a carrier gas).

Along with their total emissions from cover gas use, facilities would be required to submit supplemental data (as well as the supplemental data required in the combustion and calcination sections) including the type of production processes (e.g., primary, secondary, die casting), mass of magnesium produced or processed in metric tons for each process type, cover gas flow rate and composition, and mass of any CO_2 used as a carrier gas during reporting period.

If data were missing, facilities would be required to report the length of time the data were missing, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated. Facilities would also submit an explanation for any significant change in emission rate. Examples could include installation of new melt protection technology that would account for reduced emissions in any given year, or occurrence or repair of leaks in the cover gas delivery system.

These non-emissions data need to be reported because they are needed to understand the nature of the facilities for which data are being reported and for verifying the reasonableness of the reported data.

6. Selection of Records That Must Be Retained

We are proposing that magnesium producers and processors be required to keep records documenting adherence to the QA/QC requirements specified in the proposed rule. These records would include: Check-out and weigh-in sheets and procedures for cylinders; accuracy certifications and calibration records for scales; residual gas amounts in cylinders sent back to suppliers; and invoices for gas purchases and sales.

These records are being specified because they are the values that are used to calculate the GHG emissions that are reported. They are necessary to verify that the GHG emissions monitoring and calculations were done correctly and accurately.

U. Miscellaneous Uses of Carbonates

1. Definition of the Source Category

Limestone ($CaCO_3$), dolomite ($CaMg(CO_3)_2$) and other carbonates are inputs used in a number of industries. The most common applications of limestone are used as a construction aggregate (78 percent of specified national consumption in 2006), the chemical and metallurgy industries (18 percent), and other specialized applications (three percent). The breakdown of reported specified dolomite national consumption was similar to that of limestone, with the majority being used as a construction aggregate, and a lesser but still significant percent used in chemical and metallurgical applications.

For some of these applications, the carbonates undergo a calcination process in which the carbonate is sufficiently heated, generating CO_2 as a by-product. Examples of such emissive applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization systems for utility and industrial plants, and as a raw material in the production of mineral wool or magnesium. Non-emissive applications include limestone used in producing poultry grit and asphalt filler.

The use of limestone, dolomite and other carbonates is purely an industrial process source of emissions. Emissions from the use of carbonates in the manufacture of cement, ferroalloys, glass, iron and steel, lead, lime, pulp and paper, and zinc are elaborated in proposed 40 CFR part 98, subparts H, K, N, Q, R, S, AA and GG, since they are relatively significant emitters. Facilities that include only these source categories would not need to follow the methods presented in this section to estimate emissions from the miscellaneous use of carbonates. The methods presented in this section should be used by facilities that use carbonates in source categories other than those listed above, but which are covered by the proposed rule.

As estimated in the U.S. GHG Inventory, national process emissions from other limestone and dolomite uses (i.e., excluding cement, lime, and glass manufacturing) were 7.9 million metric tons CO_2e in 2006 (0.1 percent of U.S. emissions). CH_4 and N_2O are not released from the calcination of carbonates.

For additional background information on the use of limestone, dolomite and other carbonates, please refer to the Miscellaneous Uses of Carbonates TSD (EPA–HQ–OAR–2008–0508–021).

2. Selection of Reporting Threshold

A separate threshold analysis is not proposed for uses of limestone, dolomite and other carbonates as these emissions occur in a large number of facilities across a range of industries. We propose that facilities with source categories identified in proposed 40 CFR 98.2(a)(1) or (a)(2) consuming limestone, dolomite and other carbonates calculate the relevant emissions from their facility, including emissions from calcination of carbonates, to determine whether they surpass the proposed threshold for that industry. Data were not available to quantify emissions from the calcination of carbonates across all industries; therefore, these emissions were considered where appropriate in the thresholds analysis for the respective industries.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from the use of limestone, dolomite and other carbonates (e.g., the 2006 IPCC Guidelines, U.S. Inventory, DOE 1605(b), the EU Emissions Trading System, and the Australian National Greenhouse Gas Reporting Program). These methodologies all rely on measuring the consumption of carbonate inputs, but differ in their use of default values. The range of default values reflect differing assumptions of the carbonate weight fraction in process inputs; for example, the 2006 IPCC Guidelines Tier 1 and 2 assume that carbonate inputs are 95 percent pure (i.e., 95 percent of the mass consumed is carbonate), whereas the Australian Program assumes a default purity of 90 percent for limestone, 95 percent for dolomite, and 100 percent for magnesium carbonate.

We propose that facilities estimate process emissions by measuring the type and quantity of carbonate input to a kiln or furnace and applying the appropriate emissions factors for the carbonates consumed. In order to assess the composition of the carbonate input, we propose that facilities send samples of each carbonate consumed to an off-site laboratory for a chemical analysis of the carbonate weight fraction on an annual basis. Emission factors are based on stoichiometry and are presented in Table U–1 of this preamble. You would also be required to determine the calcination fraction for each of the carbonate-based minerals consumed, using an appropriate test method. The calcination fraction is the fraction of carbonate that is volatilized in the process. A calcination fraction of 1.0 could over estimate CO_2 emissions. You would refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

TABLE U–1. CO_2 EMISSION FACTORS FOR COMMON CARBONATES

Mineral name—carbonate	CO_2 emission factor (metric tons ons CO_2/metric tons on carbonate)
Limestone—$CaCO_3$	0.43971
Magnesite—$MgCO_3$	0.52197
Dolomite—$CaMg(CO_3)_2$	0.47732
Siderite—$FeCO_3$	0.37987
Ankerite—$Ca(Fe,Mg,Mn)(CO_3)_2$	*0.44197
Rhodochrosite—$MnCO_3$	0.38286
Sodium Carbonate/Soda Ash—Na_2CO_3	0.41492

*This is an average of the range provided by the 2006 IPCC Guidelines.

We also considered but decided not to propose simplified methods (similar to IPCC Tier 1 and 2) for quantifying process-related emissions from this source, which assumes that limestone and dolomite are the only carbonates consumed, and allow for the use of default fractions of the two carbonates (85 percent for limestone and 15 percent for dolomite). Default factors do not account for variability in relative carbonate consumption by other sources and therefore inaccurately estimate emissions.

The various approaches to monitoring GHG emissions are elaborated in the Miscellaneous Uses of Carbonates TSD (EPA–HQ–OAR–2008–0508–021).

4. Selection of Procedures for Estimating Missing Data

We propose that 100 percent data availability is required. If chemical analysis on the fraction calcination of carbonates consumed were lost or missing, the analysis would have to be repeated. It is assumed that a facility would be able to supply facility-specific carbonate consumption data. The likelihood for missing data is low, as businesses closely track production inputs.

5. Selection of Data Reporting Requirements

We propose that facilities report annual CO_2 emissions from carbonate consumption. In addition, we are proposing that facilities submit the following data which are the basis of the emission calculation and are needed for us to understand the emissions data and assess the reasonableness of the reported emissions: annual carbonate consumption (in metric tons, by carbonate) and the total fraction of calcination achieved (for each carbonate). A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and U.

6. Selection of Records That Must Be Retained

We propose that facilities retain records on monthly carbonate consumption (by type), annual records on the fraction of calcination achieved (by carbonate type), and results of the annual chemical analysis. These records provide values that are directly used to calculate the emissions that are reported and are necessary to allow determination of whether the GHG emissions monitoring and calculations were done correctly. A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and U.

V. Nitric Acid Production

1. Definition of the Source Category

Nitric acid is an inorganic chemical that is used in the manufacture of nitrogen-based fertilizers, adipic acid, and explosives. Nitric acid is also used for metal etching and processing of ferrous metals. A nitric acid production facility uses oxidation, condensation, and absorption to produce a weak nitric acid (30 to 70 percent in strength). The production process begins with the stepwise catalytic oxidation of ammonia (NH_3) through nitric oxide (NO) to nitrogen dioxide (NO_2) at high temperatures. Then the NO_2 is absorbed in and reacted with water (H_2O) to form nitric acid (HNO_3).

According to a facility-level inventory for 2006, there are 45 nitric acid production facilities operating in 25 States with a total of 65 process lines. These facilities represent the best available data at the time of this rulemaking. Using the facility-level inventory, production levels for 2006 have been estimated at 6.6 million metric tons of nitric acid and indicate an estimated 17.7 million metric tons CO_2e of process-related emissions (this represents the CO_2 equivalent of N_2O emissions, which is the primary process-related GHG). Nitric Acid process emissions were estimated in the U.S. GHG Inventory at 15.4 million metric tons CO_2e in 2006 or 0.2 percent of total U.S. GHG emissions. The main reason for the difference in estimates is that the methodology of the U.S. Inventory assumed 20 percent of the nitric acid facilities were using nonselective catalytic reduction as an N_2O abatement technology. The facility-level analysis showed that only five percent of the nitric acid facilities are using nonselective catalytic reduction.

Stationary combustion emissions were not estimated at the source category level in the U.S. GHG Inventory. Stationary combustion emissions at nitric acid facilities may be associated with other chemical production processes as well (such as adipic acid production, phosphoric acid production, or ammonia manufacturing).

For additional background information on nitric acid production, please refer to the Nitric Acid Production TSD (EPA–HQ–OAR–2008–0508–022).

2. Selection of Reporting Threshold

In developing the proposed threshold for nitric acid production, we considered emissions-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. Table V–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE V–1. THRESHOLD ANALYSIS FOR NITRIC ACID PRODUCTION

N_2O emission threshold (metric tons CO_2e)	Process N_2O emissions covered (metric tons CO_2e/yr)		Facilities covered	
	Number	Percent	Number	Percent
1,000	17,731,650	100	45	100
10,000	17,723,576	99.9	44	97.8

TABLE V–1. THRESHOLD ANALYSIS FOR NITRIC ACID PRODUCTION—Continued

N_2O emission threshold (metric tons CO_2e)	Process N_2O emissions covered (metric tons CO_2e/yr)		Facilities covered	
	Number	Percent	Number	Percent
25,000	17,706,259	99.9	43	95.6
100,000	17,511,444	98.8	40	88.9

We are proposing all nitric acid facilities report in order to simplify the rule and avoid the need for each facility to calculate and report whether it exceeds the threshold value. Facility-level emissions estimates based on plant production suggests that all known facilities, except two, exceed the 25,000 metric tons CO_2e threshold. When facility-level production data were not known, capacity data were used along with a utilization factor of 70 percent. The utilization factor is based on total 2006 nitric acid production from the U.S. Census Bureau and capacity estimates from publicly available sources.

This analysis, however, only took into account process-related emissions, as combustion-related emissions were not available. Had combustion-related emissions been included, it is probable that additional facilities would have been covered at each threshold. An ''all in'' threshold captures 100 percent of emissions without significantly increasing the number of facilities required to report. Finally, the cost of reporting using the proposed monitoring method does not vary significantly between the four different emissions based thresholds.

For a full discussion of the threshold analysis, please refer to the Nitric Acid Production TSD (EPA–HQ–OAR–2008–0508–022). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating these emissions (e.g. 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), TCR, and EPA NSPS). These methodologies coalesce around the five options discussed below.

Option 1. Apply default emission factors to total facility production of nitric acid using the Tier 1 approach established by the IPCC. The emissions are calculated using the total production of nitric acid and the highest international default emission factor available in the 2006 IPCC Guidelines, based on technology type. It also assumes no abatement of N_2O emissions.

Option 2. Apply default emission factors on a site-specific basis using the Tier 2 approach established by the IPCC. This approach is also consistent with the DOE 1605(b) ''B'' rated approach. These emission factors are dependent on the type of nitric acid process used, the type of abatement technology used, and the production activity. The process-related N_2O emissions are then estimated by multiplying the emission factor by the production level of nitric acid (on a 100 percent acid basis).

Option 3. Follow the Tier 3 approach established by IPCC using periodic direct monitoring of N_2O emissions to determine the relationship between nitric acid production and the amount of N_2O emissions; i.e., develop a site-specific emissions factor. The site-specific emission factor would be determined from an annual measurement or a single annual stack test. The site-specific emissions factor developed from this test and production rate (activity level) is used to calculate N_2O emissions. After the initial test, annual testing of N_2O emissions would be required each year to estimate the emission factor and applied to production to estimate emissions. The yearly testing would assist in verifying the emission factor. Testing would also be required whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test.

Option 4. Follow the approach used by the Nitric Acid NSPS (40 CFR part 60, subpart G). This option would require monitoring NO_X emissions on a continuous basis and measuring N_2O emissions to establish a site-specific emission factor that relates NO_X emissions to N_2O emissions. The emission factor would then be used to estimate N_2O emissions based on continuous reading of NO_X emissions. Periodic measurement would also be required to verify the emission factor over time. Testing would also be required whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test.

Option 5. Follow the Tier 3 approach established by IPCC using continuous monitoring. Use CEMS to directly measure N_2O concentration and flow rate to directly determine N_2O emissions. CEMS that measure N_2O emissions directly are available, but the nitric acid industry is currently using only NO_X CEMS.

Proposed Option. We are proposing Option 3 to quantify N_2O process emissions from all nitric acid facilities. You would be required to follow the requirements in proposed 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4 and N_2O from stationary combustion. We identified Options 3, 4, and 5 as the approaches providing the highest certainty and the best site-specific estimates. These three options span the range of types of methodologies currently used that do not apply default values. These options all use site-specific approaches that would provide insight into different levels of emissions caused by site-specific differences in process operation and abatement technologies. Option 3 requires an annual test of N_2O emissions and the establishment of a site-specific emissions factor that relates N_2O emissions with the nitric acid production rate.

Options 4 and 5 are similar in that both use continuous monitoring to calculate N_2O emissions. Option 5 directly measures the N_2O emissions. Option 4 uses continuous measurement of NO_X emissions to estimate a site-specific emission factor that relates NO_X emissions to N_2O emissions. The emission factor is then used to estimate N_2O emissions based on continuous readings of NO_X emissions.

Option 5 would provide the highest certainty of the three options and capture the smallest changes in N_2O emissions over time, but N_2O CEMS are not currently in use in the industry and there is no existing EPA method for certifying N_2O CEMS. Option 3 and Option 4 use site-specific emission factors so the margin of error is much lower than using default emission factors. Option 4 would require the use of NO_X CEMS that are already in use by many nitric acid facilities to automatically capture and record any changes in NO_X emissions over time. However, NO_X CEMS only capture emissions of NO and NO_2 and not N_2O. Therefore they would not be useful in the estimation of N_2O emissions from nitric acid production facilities. Although the amount of NO_X and N_2O emissions from nitric acid production may be directly related, direct measurement of NO_X does not automatically correlate to the amount of N_2O in the same exhaust stream. Periodic testing of N_2O emissions (Option 3) would not indicate changes in emissions over short periods of time, but does offer direct measurement of the GHG.

We request comment, along with supporting documentation, on the advantages and disadvantages of using Options 3, 4 and 5. After consideration of public comments, EPA may promulgate one or more of these options or a combination based on the additional information that is provided.

We decided not to propose Options 1 and 2 because the use of default values and lack of direct measurements results in a high level of uncertainty. Although different default emissions factors have been developed for different processes (e.g., low pressure, high pressure) and abatement techniques, the use of these default values is more appropriate for sector wide or national total estimates than for determining emissions from a specific facility. Site-specific emission factors are more appropriate for reflecting differences in process design and operation.

The various approaches to monitoring GHG emissions are elaborated in the Nitric Acid Production TSD (EPA–HQ–OAR–2008–0508–022).

4. Selection of Procedures for Estimating Missing Data

For process sources that use a site-specific emission factor, no missing data procedures would apply because the site-specific emission factor is derived from an annual performance test and used in each calculation. The emission factor would be multiplied by the production rate, which is readily available. If the test data is missing or lost, the test would have to be repeated. Therefore, 100 percent data availability would be required.

5. Selection of Data Reporting Requirements

We propose that facilities report annual N_2O emissions (in metric tons) from each nitric acid production line. In addition, we propose that facilities submit the following data to understand the emissions data and verify the reasonableness of the reported emissions. The data should include annual nitric acid production capacity, annual nitric acid production, type of nitric acid production process used, number of operating hours in the calendar year, the emission rate factor used, abatement technology used (if applicable), abatement technology efficiency, and abatement utilization factor.

Capacity, actual production, and operating hours would be helpful in determining the potential for growth in the nitric acid industry. The production rate can be determined through sales records or by direct measurement using flow meters or weigh scales. This industry generally measures the production rate as part of normal operating procedures.

A list of abatement technologies would be helpful in assessing how widespread the use of abatement is in the nitric acid source category, cataloging any new technologies that are being used, and documenting the amount of time that the abatement technologies are being used.

A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and V.

6. Selection of Records That Must Be Retained

We propose that facilities maintain records of significant changes to process, N_2O abatement technology used, abatement technology efficiency, abatement utilization factor (percent of time that abatement system is operating), annual testing of N_2O emissions, calculation of the site-specific emission rate factor, and annual production of nitric acid.

A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and V.

W. Oil and Natural Gas Systems

1. Definition of the Source Category

The U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. This section of the preamble identifies relevant facilities and outlines methods and procedures for calculating and reporting fugitive emissions (as defined in this section) of CH_4 and CO_2 from the petroleum and natural gas industry. Methods and reporting procedures for emissions resulting from natural gas or crude oil combustion in prime movers such as compressors are covered under Section V.C of this preamble.

The natural gas segment involves production, processing, transmission and storage, and distribution of natural gas. The U.S. also receives, stores, and processes imported liquefied natural gas (LNG) at LNG import terminals. The petroleum segment involves crude oil production, transportation and refining.

The relevant facilities covered in this section are offshore petroleum and natural gas production facilities, onshore natural gas processing facilities (including gathering/boosting stations), onshore natural gas transmission compression facilities, onshore natural gas storage facilities, LNG storage facilities, and LNG import facilities. Fugitive emissions from petroleum refineries are proposed for inclusion in the rulemaking, but these emissions are addressed in the petroleum refinery section (Section V.Y) of this preamble. Under this section of the preamble, we seek comment on methods for reporting fugitive emissions data from: On-shore petroleum and natural gas production and natural gas distribution facilities.

For this rulemaking, fugitive emissions from the petroleum and natural gas industry are defined as unintentional equipment emissions and intentional or designed releases of CH_4- and/or CO_2-containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. In the context of this rule, fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares. These emissions are hereafter collectively referred to as ‘‘fugitive emissions’’ or ‘‘emissions’’. We seek comment on the proposed definition of fugitives, which is derived from the definition of fugitive emissions outlined in the 2006 IPCC Guidelines for National GHG Inventories, and is often used in the development of GHG inventories. We acknowledge that there are multiple definitions for fugitives, for example, defining the term fugitives to include ‘‘those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening’’. According to the 2008 U.S. Inventory, total fugitive emissions of CH_4 and CO_2 from the natural gas and petroleum industry were 160 metric tons CO_2e in 2006. The breakdown of these fugitive emissions is shown in Table W–1 of this preamble.

TABLE W–1. FUGITIVE EMISSIONS FROM PETROLEUM AND NATURAL GAS SYSTEMS (2006)

Sector	Fugitive CH_4 ($MMTCO_2e$)	Fugitive CO_2 ($MMTCO_2e$)
Natural Gas Systems[1]	102.4	28.5
Petroleum Systems	28.4	0.3

[1] Emissions account for Natural Gas STAR Partner Reported Reductions.

Natural gas system fugitive CH_4 emissions resulted from onshore and offshore natural gas production facilities (27 percent); onshore natural gas processing facilities (12 percent); natural gas transmission and underground natural gas storage, including LNG import and LNG storage facilities (37 percent); and natural gas distribution facilities (24 percent). Natural gas segment fugitive CO_2 emissions were primarily from onshore natural gas processing facilities (74 percent), followed by onshore and offshore natural gas production facilities (25 percent), and less than 1 percent each from natural gas transmission and underground natural gas storage and distribution facilities.[80]

Petroleum segment fugitive CH_4 emissions are primarily associated with onshore and offshore crude oil production facilities (>97 percent of emissions) and petroleum refineries (2 percent) and are negligible in crude oil transportation facilities (<0.5 percent). Petroleum segment fugitive CO_2 emissions are only estimated for onshore and offshore production facilities.

With over 160 different sources of fugitive CH_4 and CO_2 emissions in the petroleum and natural gas industry, identifying those sources most relevant for a reporting program was a challenge. We developed a decision tree analysis and undertook a systematic review of each emissions source category included in the Inventory of U.S. GHG Emissions and Sinks. In determining the most relevant fugitive emissions sources for inclusion in this reporting program, we applied the following criteria: the coverage of fugitive emissions for the source category as a whole, the coverage of fugitive emissions per unit of the source category, feasibility of a viable monitoring method, including direct measurement and engineering estimations, and an administratively manageable number of reporting facilities.

Another factor we considered in assessing the applicability of certain petroleum and natural gas industry fugitive emissions in a mandatory reporting program is the definition of a facility. In other words, what physically constitutes a facility? This definition is important to determine who the reporting entity would be, and to ensure that delineation is clear and double counting of fugitive emissions is minimized. For some segments of the industry, identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities). In other segments of the industry, such as the pipelines between compressor stations, and more particularly onshore petroleum and natural gas production, such distinctions are not straightforward. In defining a facility, we reviewed current definitions used in the CAA and ISO definitions, consulted with industry, and reviewed current regulations relevant to the industry. The full results of our assessment can be found in the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023).

Following is a brief discussion of the proposed selected and excluded sources based on our analysis. Additional information can be found in the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023). This section of the preamble addresses only fugitive emissions. Combustion-related emissions are discussed in Section V.C of this preamble.

Offshore Petroleum and Natural Gas Production Facilities. Offshore petroleum and natural gas production includes both shallow and deep water wells in both U.S. State and Federal waters. These offshore facilities house equipment to extract hydrocarbons from the ocean floor and transport it to storage or transport vessels or onshore. Fugitive emissions result from sources housed on the platforms.

In 2006, offshore petroleum and natural gas production fugitive CO_2 and CH_4 emissions accounted for 5.6 million metric tons CO_2e. The primary sources of fugitive emissions from offshore petroleum and natural gas production are from valves, flanges, open-ended lines, compressor seals, platform vent stacks, and other source components. Flare stacks account for the majority of fugitive CO_2 emissions.

Offshore petroleum and natural gas production facilities are proposed for inclusion due to the fact that this represents approximately 4 percent of emissions from the petroleum and natural gas industry, ‘‘facilities’’ are clearly defined, and major fugitive emissions sources can be characterized by direct measurement or engineering estimation.

Onshore Natural Gas Processing Facilities. Natural gas processing includes gathering/ boosting stations that dehydrate and compress natural gas to be sent to natural gas processing facilities, and natural gas processing facilities that remove NGLs and various other constituents from the raw natural gas. The resulting ‘‘pipeline quality’’ natural gas is injected into transmission pipelines. Compressors are used within gathering/ boosting stations and also natural gas processing facilities to adequately pressurize the natural gas so that it can pass through all of the processes into the transmission pipeline.

Fugitive CH_4 emissions from reciprocating and centrifugal compressors, including centrifugal compressor wet and dry seals, reciprocating compressor rod packing, and all other compressor fugitive emissions, are the primary CH_4 emission source from this segment. The majority of fugitive CO_2 emissions come from acid gas removal vent stacks, which are designed to remove CO_2 and hydrogen sulfide, when present, from natural gas. While these are the major fugitive emissions sources in natural gas processing facilities, if other potential fugitive sources such as flanges, open-ended lines and threaded fittings are present at your facility you would need to account for them if reporting under proposed 40 CFR part 98, subpart W. For this subpart you would assume no capture of CO_2 because capture and

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[80] The distribution of CO_2 emissions is slightly misleading due to current U.S. Inventory convention which assumes that all CO_2 from natural gas processing facilities is emitted. In fact, approximately 7,000 metric tons CO_2e is captured and used for EOR.

transfer of CO_2 offsite would be calculated in accordance with Section V.PP of this preamble and reported separately.

Onshore natural gas processing facilities are proposed for inclusion due to the fact that these operations represent a significant emissions source, approximately 25 percent of emissions from the natural gas segment. ''Facilities'' are easily defined and major fugitive emissions sources can be characterized by direct measurement or engineering estimation.

Onshore Natural Gas Transmission Compression Facilities and Underground Natural Gas Storage Facilities. Natural gas transmission compression facilities move natural gas throughout the U.S. natural gas transmission system. Natural gas is also injected and stored in underground formations during periods of low demand (e.g., spring or fall) and withdrawn, processed, and distributed during periods of high demand (e.g., winter or summer). Storage compressor stations are dedicated to gas injection and extraction at underground natural gas storage facilities.

Fugitive CH_4 emissions from reciprocating and centrifugal compressors, including centrifugal compressor wet and dry seals, reciprocating compressor rod packing, and all other compressor fugitive emissions, are the primary CH_4 emission source from natural gas transmission compression stations and underground natural gas storage facilities. Dehydrators are also a significant source of fugitive CH_4 emissions from underground natural gas storage facilities. While these are the major fugitive emissions sources in natural gas transmission, other potential fugitive sources include, but are not limited to, condensate tanks, open-ended lines and valve seals.

Transmission compression facilities and underground natural gas storage facilities are proposed for inclusion due to the fact that these operations represent a significant emissions source, approximately 24 percent of emissions from the natural gas segment; ''facilities'' are easily defined, and major fugitive sources can be characterized by direct measurement or engineering estimation.

LNG Import and LNG Storage Facilities. The U.S. imports natural gas in the form of LNG, which is received, stored, and, when needed, processed and compressed at LNG import terminals. LNG storage facilities liquefy and store natural gas from transmission pipelines during periods of low demand (e.g., spring or fall) and vaporize for send out during periods of high demand (e.g., summer and winter)

Fugitive CH_4 and CO_2 emissions from reciprocating and centrifugal compressors, including centrifugal compressor wet and dry seals, reciprocating compressor rod packing, and all other compressor fugitive emissions, are the primary CH_4 and CO_2 emission source from LNG storage facilities and LNG import facilities. Process units at these facilities can include compressors to liquefy natural gas (at LNG storage facilities), re-condensers, vaporization units, tanker unloading equipment (at LNG import terminals), transportation pipelines, and/or pumps.

LNG storage facilities and LNG import facilities are proposed for inclusion due to the fact that fugitive emissions from these operations represent approximately 1 percent of emissions from natural gas systems. LNG storage ''facilities'' are defined as facilities that store liquefied natural gas in above ground storage tanks. LNG import terminal ''facilities'' are defined as facilities that receive imported LNG, store it in storage tanks, and release re-gasified natural gas for transportation.

Onshore Petroleum and Natural Gas Production. Similar to offshore petroleum and natural gas production, the onshore petroleum and natural gas production segment uses wells to draw raw natural gas, crude oil, and associated gas from underground formations. The most dominant sources of fugitive CH_4 and CO_2 emissions include, but are not limited to, natural gas driven pneumatic valve and pump devices, field crude oil and condensate storage tanks, chemical injection pumps, releases and flaring during well completion and workovers, and releases and flaring of associated gas.

We considered proposing the reporting of fugitive CH_4 and CO_2 emissions from onshore petroleum and natural gas production in the rule. Onshore petroleum and natural gas production is responsible for the largest share of fugitive CH_4 and CO_2 emissions from petroleum and natural gas industry (27 percent of total emissions). However, this segment is not proposed for inclusion primarily due to the unique difficulty in defining a ''facility'' in this sector and correspondingly determining who would be responsible for reporting.

Given the significance of fugitive emissions from the onshore petroleum and natural gas production, we would like to take comment on whether we should consider inclusion of this source category in the future. Specifically, we would like to take comment on viable ways to define a facility for onshore oil and gas production and to determine the responsible reporter. In addition, the Agency also requests comment on the merits and/or concerns with the corporate basin level reporting approach under consideration for onshore oil and gas production, as outlined below.

One approach we are considering for including onshore petroleum and natural gas production fugitive emissions in this reporting rule is to require corporations to report emissions from all onshore petroleum and natural gas production assets at the basin level. In such a case, all operators in a basin would have to report their fugitive emissions from their operations at the basin-level. For such a basin-level facility definition, we may propose reporting of only the major fugitive emissions sources; i.e., natural gas driven pneumatic valve and pump devices, well completion releases and flaring, well blowdowns, well workovers, crude oil and condensate storage tanks, dehydrator vent stacks, and reciprocating compressor rod packing. Under this scenario, we might suggest that all operators would be subject to reporting, perhaps exempting small businesses, as defined by the Small Business Administration.

This approach could substantially reduce the reporting complexity and require individual companies that produce crude oil and/or natural gas in each basin to be responsible for reporting emissions from all of their onshore petroleum and natural production operations in that basin, including from rented sources, such as compressors. In cases where hydrocarbons or emissions sources are jointly owned by more than one company, each company would report emissions equivalent to its portion of ownership.

We considered other options in defining a facility such as individual wellheads or aggregating all emissions sources prior to compression as a facility. However, such definitions result in complex reporting requirements and are difficult to implement.

We are seeking comments on reporting of the major fugitive emissions sources by corporations at the basin level for onshore petroleum and natural gas production.

Petroleum and Natural Gas Pipeline Segments. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Crude oil transportation involves pump stations to move crude oil through pipelines and loading and unloading crude oil tanks, marine vessels, and rails.

The majority of fugitive emissions from the transportation of natural gas occur at the compressor stations, which are already proposed for inclusion in the rule and discussed above. We do not propose to include reporting of fugitive emissions from natural gas pipeline segments between compressor stations, or crude oil pipelines in the rulemaking due to the dispersed nature of the fugitive emissions, the difficulty in defining pipelines as a facility, and the fact that once fugitives are found, they are generally fixed quickly, not allowing time for monitoring and direct measurement of the fugitives.

Natural Gas Distribution. In the natural gas distribution segment, high-pressure gas from natural gas transmission pipelines enter ''city gate'' stations, which reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Distribution system CH_4 and CO_2 emissions result mainly from fugitive emissions from gate stations (metering and regulating stations) and vaults (regulator stations), and fugitive emissions from underground pipelines. At gate stations and vaults, fugitive CH_4 emissions primarily come from valves, open-ended lines, connectors, and natural gas driven pneumatic valve devices.

Although fugitive emissions from a single vault, gate station or segment of pipeline in the natural gas distribution segment may not be significant, collectively these fugitive emissions sources contribute a significant share of fugitive emissions from natural gas systems.

We do not propose to include the natural gas distribution segment of the natural gas industry in this rulemaking due to the dispersed nature of the fugitive emissions and difficulty in defining a facility such that there would be an administratively manageable number of reporters.

One approach to address the concern with defining a facility for distribution would be to require corporate-level reporting of fugitive emissions from major sources by distribution companies. We seek comment on this and other ways of reporting fugitive emissions from the distribution sector.

Crude Oil Transportation. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations are storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading operations.

We do not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions, accounting for much less than 1 percent, and the difficulty in defining a facility.

2. Selection of Reporting Threshold

We propose that facilities with emissions greater than 25,000 metric tons CO_2e per year be subject to reporting. This threshold is applicable to all oil and natural gas system facilities covered by this subpart: Offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, including gathering/boosting stations; natural gas transmission compression facilities, underground natural gas storage facilities; LNG storage facilities; and LNG import facilities.

To identify the most appropriate threshold level for reporting of fugitive emissions, we conducted analyses to determine fugitive emissions reporting coverage and facility reporting coverage at four different levels of threshold; 1,000 metric tons CO_2e per year, 10,000 metric tons CO_2e per year, 25,000 metric tons CO_2e per year, and 100,000 metric tons CO_2e per year. Table W–2 of this preamble provides coverage of emissions and number of facilities reporting at each threshold level for all the industry segments under consideration for this rule.

TABLE W–2. THRESHOLD ANALYSIS FOR FUGITIVE EMISSIONS FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

Source category	Total national emissions [#a] (metric tons CO_2e per year)	Total number of facilities	Threshold level	Total emissions covered by thresholds [s]		Facilities covered	
				(metric tons CO_2e per year)	Percent	Number	Percent
Offshore Petroleum & Gas Production Facilities	10,162,179	2,525	1,000	9,783,496	96	1,021	40
			10,000	6,773,885	67	156	6
			25,000	5,138,076	51	50	2
			100,000	3,136,185	31	4	0.5
Natural Gas Processing Facilities	50,211,548	566	1,000	50,211,548	100	566	100
			10,000	49,207,852	98	394	70
			25,000	47,499,976	95	287	51
			100,000	39,041,555	78	125	22
Natural Gas Transmission Compression Facilities	73,198,355	1,944	1,000	73,177,039	100	1,659	85
			10,000	71,359,167	97	1311	67
			25,000	63,835,288	87	874	45
			100,000	30,200,243	41	216	11
Underground Natural Gas Storage Facilities	11,719,044	398	1,000	11,702,256	100	346	87
			10,000	10,975,728	94	197	49
			25,000	9,879,247	84	131	33
			100,000	5,265,948	45	35	9
LNG Storage Facilities	1,956,435	157	1,000	1,940,203	99	54	34
			10,000	1,860,314	95	39	25
			25,000	1,670,427	85	29	18
			100,000	637,477	33	3	2
LNG Import Facilities	1,896,626	5	1,000	1,896,626	100	5	100

TABLE W–2. THRESHOLD ANALYSIS FOR FUGITIVE EMISSIONS FROM THE PETROLEUM AND NATURAL GAS INDUSTRY—Continued

Source category	Total national emissions [#a] (metric tons CO_2e per year)	Total number of facilities	Threshold level	Total emissions covered by thresholds [s]		Facilities covered	
				(metric tons CO_2e per year)	Percent	Number	Percent
			10,000	1,895,153	99.9	4	80
			25,000	1,895,153	99.9	4	80
			100,000	1,895,153	99.9	4	80

[a] The emissions include fugitive CH_4 and CO_2 and combusted CO_2, N_2O, and CH_4 gases. The emissions for each industry segment do not match the 2008 U.S. Inventory either because of added details in the estimation methodology or use of a different methodology than the U.S. Inventory. For additional discussion, refer to the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023).

A proposed threshold of 25,000 metric tons CO_2e applied to only those emissions sources listed in Table W–2 of this preamble captures approximately 81 percent of fugitive CH_4 and CO_2 emissions from the entire oil and natural gas industry, while capturing only a small fraction of total facilities. For additional information, please refer to the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating fugitive emissions from oil and natural gas operations, including the 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), and corporate industry protocols developed by the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association. The methodologies proposed vary by the emissions source, for example fugitive emissions versus vented emissions, versus emissions from flares (all of which are considered ‘‘fugitive’’ emissions in this rulemaking). Generally, approaches range from direct measurement (e.g., high volume samplers), to engineering equations (where applicable), to simple emission factor approaches based on national default factors.

Proposed Option. We propose that facilities would be required to detect fugitive emissions from the identified emissions sources proposed in this rulemaking, and then quantify emissions using either engineering equations or direct measurement.

Fugitive emissions from all affected emissions sources at the facility, whether in operating condition or on standby, would have to be monitored on an annual basis. The proposed monitoring method would depend on the fugitive emissions sources in the facility to be monitored. Each fugitive emissions source would be required to be monitored using one of the two monitoring methods: (1) Direct measurement or (2) engineering estimation. Table W–3 of this preamble provides the proposed fugitive emissions source and corresponding monitoring methods. General guidance on the monitoring methods is given below.

TABLE W–3. SOURCE SPECIFIC MONITORING METHODS AND EMISSIONS QUANTIFICATION

Emission source	Monitoring method type	Emissions quantification methods
Acid Gas Removal Vent Stacks	Engineering estimation	Simulation software.
Blowdown Vent Stacks	Engineering estimation	Gas law and temperature, pressure, and volume between isolation valves.
Centrifugal Compressor Dry Seals	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Centrifugal Compressor Wet Seals	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Compressor Fugitive Emissions	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Dehydrator Vent Stacks	Engineering estimation	Simulation software.
Flare Stacks	Engineering estimation and direct measurement.	Velocity meter and mass/volume equations.
Natural Gas Driven Pneumatic Pumps	(1) Engineering estimation, or (2) Direct measurement.	(1) Manufacturer data, equipment counts, and amount of chemical pumped, or (2) Calibrated bag.
Natural Gas Driven Pneumatic Manual Valve Actuator Devices.	(1) Engineering estimation, or (2) Direct measurement.	(1) Manufacturer data and actuation logs, or (2) Calibrated bag.
Natural Gas Driven Pneumatic Valve Bleed Devices.	(1) Engineering estimation, or (2) Direct measurement.	(1) Manufacturer data and equipment counts, or (2) High volume sampler, or (3) Calibrated bag, or (4) Meter.
Non-pneumatic Pumps	Direct measurement	High volume sampler.
Offshore Platform Pipeline Fugitive Emissions	Direct measurement	High volume sampler.
Open-ended Lines	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Pump Seals	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Facility Fugitive Emissions	Direct measurement	High volume sampler.

TABLE W–3. SOURCE SPECIFIC MONITORING METHODS AND EMISSIONS QUANTIFICATION—Continued

Emission source	Monitoring method type	Emissions quantification methods
Reciprocating Compressor Rod Packing	Direct measurement	(1) High volume sampler, or (2) Calibrated bag, or (3) Meter.
Storage Tanks	(1) Engineering estimation and direct measurement, or (2) Engineering estimation.	(1) Meter, or (2) Simulation software, or (3) Vasquez-Beggs Equation.

a. Direct Measurement

Fugitive emissions detection and measurement are both required in cases where direct measurement is being proposed. Infrared fugitive emissions detection instruments are capable of detecting fugitive CH_4 emissions, or Toxic Vapor Analyzers or Organic Vapor Analyzers can be used by the operator to detect fugitive natural gas emissions. These instruments detect the presence of hydrocarbons in the natural gas fugitive emissions stream. They do not detect any pure CO_2 fugitive emissions. However, because all the sources proposed for monitoring have natural gas fugitive emissions that have CH_4 as one of its constituents, there is no need for a separate detection instrument for separately detecting CO_2 fugitive emissions. The only exception to this is fugitive emissions from acid gas removal vent stacks where the predominant constituent of the fugitive emissions is CO_2. Engineering estimation is proposed for this source, and therefore there is no need for detection of fugitive emissions from acid gas removal vent stacks.

In the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023), we describe a particular method based on practicality of application. For example, using Toxic Vapor Analyzers or Organic Vapor Analyzers on very large facilities is not as cost effective as infrared fugitive emissions detection instruments. We propose that irrespective of the method used for fugitive natural gas emissions detection, the survey for detection must be comprehensive. This means that, on an annual basis, the entire population of emissions sources proposed for fugitive emissions reporting has to be surveyed at least once. When selecting the appropriate emissions detection instrument, it is important to note that certain instruments are best suited for particular applications and circumstances. For example, some optical infrared fugitive emissions detection instruments may not perform well in certain weather conditions or with certain colored backgrounds.

Infrared fugitive emissions detection instruments are able to scan hundreds of source components at once, allowing for efficient detection of emissions at large facilities; however, infrared fugitive emissions detection instruments are typically much more expensive than other options. Organic Vapor Analyzers and Toxic Vapor Analyzers are not able to detect fugitive emissions from many components as quickly; however, for small facilities this may provide a less costly alternative to infrared fugitive emissions detection without requiring overly burdensome labor to perform a comprehensive fugitive emissions survey. We propose that operators choose the instrument from the choices provided in the proposed rule that is best suited for their circumstance. Further information is contained in the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023).

For direct measurement, we have proposed that high volume samplers, meters (such as rotameters, turbine meters, hot wire anemometers, and others), and/or calibrated bags be designated for use. However, if fugitive emissions exceed the maximum range of the proposed monitoring instrument, you would be required to use a different instrument option that can measure larger magnitude emissions levels. For example, if a high volume sampler is pegged by a fugitive emissions source, then fugitive emissions would be required to be directly measured using either calibrated bagging or a meter. In the Oil and Natural Gas Systems TSD (EPA–HQ–OAR–2008–0508–023), we discuss multiple options for measurement where the range of emissions measurement instruments is seen as an issue. CH_4 and CO_2 fugitive emissions from the natural gas fugitive emissions stream can be calculated using the composition of natural gas.

b. Engineering Estimation

Engineering estimation has been proposed for calculating CH_4 and CO_2 fugitive emissions from sources where the variable in the emissions magnitude on an annual basis is the number of times the source releases fugitive CH_4 and CO_2 emissions to the atmosphere. For example, when a compressor is taken offline for maintenance, the volume of fugitive CH_4 and CO_2 emissions that are released is the same during each release and the only variable is the number of times the compressor is taken offline. Also, engineering estimates have been proposed where safety concerns prohibit the use of direct measurement methods. For example, sometimes the temperature of the fugitive emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure fugitive emissions. Based on these principles, we propose that direct measurement is mandatory unless there is a demonstrated and documented safety concern or frequency of fugitive emission releases is the only variable in emissions, at which time engineering estimates can be applied.

c. Alternative Monitoring Methods Considered

Before proposing the monitoring methods discussed above, we considered four additional measurement methods. The use of Method 21 or the use of activity and emission factors were considered for fugitive emissions detection and measurement. Although Toxic Vapor Analyzers and Organic Vapor Analyzers were considered but not proposed for fugitive emissions direct measurement they are acceptable for fugitive emissions detection.

Method 21. This is the reference method for equipment leak detection and repair regulations for volatile organic carbon (VOC) emissions under several 40 CFR part 60 emission standards. Method 21 of 40 CFR part 60 Appendix A–7 determines a concentration at a point or points of emissions expressed in parts per million concentration of combustible hydrocarbon in the air stream of the instrument probe. This concentration is then compared to the ‘‘action level’’ in the referenced 40 CFR part 60 regulation to determine if a leak is present. Although Method 21 was not developed for this purpose, it may allow for better emission estimation than the overall average emission factors that have been published for equipment leaks. Quantification of air emissions from equipment leaks is generally done using EPA published guidelines which correlate the measured concentration to a VOC mass emission rate based on extensive measurements of air emissions from leaking equipment. The correlations are statistically determined for a very large population of similar components, but not very accurate for single leaks or small populations. Therefore, Method 21 was not found suitable for fugitive emissions measurement under this reporting rule. However, we are seeking comments on this conclusion, and whether Method 21 should be permitted as a viable alternative method to estimate emissions for sources where it is currently required for VOC emissions.

Activity Factor and Emissions Factor for All Sources. Fugitive CH_4 emissions factors for all of the fugitive emissions sources proposed for inclusion in the rule are available in a study that was conducted in 1992.[81] [82] There have been no subsequent comparable studies published to replace or revise the fugitive emissions estimates available from this study. However, some petroleum and natural gas industry operations have changed significantly with the introduction of new technologies and improved operating and maintenance practices to mitigate fugitive emissions. These are not reflected in the fugitive emissions factors available. Also, in many cases the fugitive emissions factors are not representative of emission levels for individual sources or are not relevant to certain operations because the estimates were based on limited or no field data. Hence, they are not representative of the entire country or specific petroleum and natural gas facilities and fugitive emissions sources such as tanks and wells. Therefore, we did not propose this method for estimation of the fugitive emissions for reporting.

Default fugitive CO_2 emissions factors are available only for whole segments of the industry (e.g., natural gas processing), and are not available for individual sources. Further, these are international default factors, which have a high uncertainty associated with them and are not appropriate for facility-level reporting.

Mass Balance for Quantification. We considered, but decided not to propose, the use of a mass balance approach for quantifying emissions. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. For transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings and the large volumes of throughput relative to fugitive emissions. We are seeking feedback on the use of a mass balance approach and the applicability to each sector of the oil and gas industry (production, processing, transmission, and distribution) as a potential alternative to component level leak detection and quantification.

Toxic Vapor Analyzers and Organic Vapor Analyzers for Emissions Measurement. Toxic Vapor Analyzer and Organic Vapor Analyzer instruments quantify the concentration of combustible hydrocarbon from the fugitive emission in the air stream, but do not directly quantify the volumetric or mass emissions. The instrument probe rarely ingests all of the natural gas from a fugitive emissions source. Therefore, these instruments are used primarily for fugitive emissions leak detection. For the proposed rule, fugitive CH_4 emissions detection by more cost-effective detection technologies such as infrared fugitive emissions detection instruments in conjunction with direct measurement methodologies such as the high volume sampler, meters and calibrated bags is deemed a better overall approach to fugitive emissions quantification than the labor intensive Organic Vapor Analyzers and Toxic Vapor Analyzers, which do not quantify volumetric or mass fugitive emissions.

d. Outstanding Issues on Which We Seek Comments

The proposed rule does not indicate a particular threshold for detection above which emissions measurement is required. This is because the different emissions detection instruments proposed have different levels and types of detection capabilities. Hence the magnitude of actual emissions can only be determined after measurement. This, however, does not serve the purpose of this rule in limiting burden on emissions reporting. A facility can have hundreds of small emissions (as low as 3 grams per hour) and it might not be practical to measure all such small emissions for reporting.

To address this issue we intend to incorporate one of the following two approaches in the final rule.

The first approach would provide performance standards for fugitive emissions detection instruments and usage such that all instruments follow a common minimum detection threshold. We may propose the use of the Alternate Work Practice to Detect Leaks from Equipment standards for infrared fugitive emissions detection instruments being developed by EPA. In such a case all detected emissions from components subject to this rule would require measurement and reporting.

The second approach would provide an emissions threshold above which the source would be identified as an ‘‘emitter’’ for emissions detection using Organic Vapor Analyzers or Toxic Vapor Analyzers. When using infrared fugitive emissions detection instruments all sources subject to this rule that have emissions detected would require emissions quantification. Alternatively, the operator would be given a choice of first detecting emissions sources using the infrared detection instrument and then verifying for measurement status using the emissions definition for Organic Vapor Analyzers or Toxic Vapor Analyzers.

We are seeking comments on using the two options discussed above for determining emission sources requiring measurement of emissions.

Some fugitive emissions by nature occur randomly within the facility. Therefore, there is no way of knowing when a particular source started emitting. This proposed rule requires annual fugitive emissions detection and measurement. The emissions detected and measured would be assumed to continue throughout the reporting year, unless no emissions detection is recorded at an earlier and/or later point in the reporting period. We recognize that this may not necessarily be true in all cases and that emissions reported would be higher than actual. Therefore, we are seeking comments on how this issue can be resolved without resulting in additional reporting burden to the facilities.

The petroleum and natural gas industry is already implementing voluntary fugitive emissions detection and repair programs. Such voluntary programs are useful, but pose an accounting challenge with respect to emissions reporting for this rule. The proposed rule requires annual detection and measurement of fugitive emissions. This approach does not preclude any facility from performing emissions detection and repair prior to the official detection, measurement, and reporting of emissions for this rule. We are seeking comments on how to avoid under-reporting of emissions as a result of a preliminary, ‘‘un-official’’ emissions

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[81] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry.* Harrison, M., T. Shires, J. Wessels, and R. Cowgill, (eds.). Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA–600/R–96–080a.

[82] EPA (1999) *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report).* Prepared by ICF International. Office of Air and Radiation, U.S. Environmental Protection Agency. October 1999.

survey and repair exercise ahead of the ''official'' annual survey.

Fugitive emissions from a compressor are a function of the mode in which the compressor is operating. Typically, a compressor station consists of several compressors with one (or more) of them on standby based on system redundancy requirements and peak delivery capacity. Fugitive emissions at compressors in standby mode are significantly different than those from compressors that are operating. The rule proposes annual direct measurement of fugitive emissions. This may not adequately account for the different modes in which a particular compressor is operating through the reporting period. We are soliciting input on a method to measure emissions from each mode in which the compressor is operating, and the period of time operated in that mode, that would minimize reporting burden. Specifically, given the variability of these measured emissions, EPA requests comment on whether engineering estimates or other alternative methods that account for total emissions from compressors, including open ended lines, could address this issue of operating versus standby mode.

The fugitive emissions measurement instruments (i.e. high volume sampler, calibrated bags, and meters) proposed for this rule measure natural gas emissions. CH_4 and CO_2 emissions are required to be estimated from the natural gas mass emissions using natural gas composition appropriate for each facility. For this purpose, the proposed rule requires that facilities use existing gas composition estimates to determine CH_4 and CO_2 components of the natural gas emissions (flare stack and storage tank fugitive emissions are an exception to this general rule). We have determined that these gas composition estimates are available from facilities reporting to this rule. We are seeking comments on whether this is a practical assumption. In the absence of gas composition, an alternative proposal would be to require the periodic measurement of the required gas composition for speciation of the natural gas mass emissions into CH_4 and CO_2 mass emissions.

4. Selection of Procedures for Estimating Missing Data

The proposal requires data collection for a single source a minimum of once a year. If data are lost or an error occurs during fugitive emissions direct measurement, the operator should carry out the direct measurement a second time to obtain the relevant data point(s). Similarly, engineering estimates must account for relevant source counts and frequency of fugitive emissions releases throughout the year. There should not be any missing data for estimating fugitive emissions from petroleum and natural gas systems.

5. Selection of Data Reporting Requirements

We propose that fugitive emissions from the petroleum and natural gas industry be reported on an annual basis. The reporting should be at a facility level with fugitive emissions being reported at the source type level. Fugitive emissions from each source type could be reported at an aggregated level. In other words, process unit-level reporting would not be required. For example, a facility with multiple reciprocating compressors could report fugitive emissions from all reciprocating compressors as an aggregate number. Since the proposed monitoring method is fugitive emissions detection and measurement at the source level, we determined that reporting at an aggregate source type level is feasible.

Fugitive emissions from all sources proposed for monitoring, whether in operating condition or on standby, would have to be reported. Any fugitive emissions resulting from standby sources would be separately identified from the aggregate fugitive emissions.

The reporting facility would be required to report the following information to us as a part of the annual fugitive emissions reporting: fugitive emissions monitored at an aggregate source level for each reporting facility, assuming no carbon capture and transfer offsite; the quantity of CO_2 captured for use and the end use, if known; fugitive emissions from standby sources; and activity data for each aggregate source type level.

Additional data are proposed to be reported to support verification: Engineering estimate of total component count; total number of compressors and average operating hours per year for compressors, if applicable; minimum, maximum and average throughput per year; specification of the type of any control device used, including flares; and detection and measurement instruments used. For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both is proposed to be reported. For compressors specifically, we proposed that the total number of compressors and average operating hours per year be reported.

A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and W.

6. Selection of Records That Must Be Retained

The reporting facility shall retain relevant information associated with the monitoring and reporting of fugitive emissions to us, as follows; throughput of the facility when the fugitive emissions direct measurement was conducted, date(s) of measurement, detection and measurement instruments used, if any, results of the leak detection survey, and inputs and outputs to calculations or simulation software runs where the proposed monitoring method requires engineering estimation.

A full list of records to be retained is included inproposed 40 CFR part 98, subparts A and W.

X. Petrochemical Production

1. Definition of the Source Category

The petrochemical industry consists of numerous processes that use fossil fuel or petroleum refinery products as feedstocks. For this proposed GHG reporting rule, the reporting of process-related emissions in the petrochemical industry is limited to the production of acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, and methanol. The petrochemicals source category includes production of all forms of carbon black (e.g., furnace black, thermal black, acetylene black, and lamp black) because these processes use petrochemical feedstocks; bone black is not considered to be a form of carbon black because it is not produced from petrochemical feedstocks. The rule focuses on these six processes because production of GHGs from these processes has been recognized by the IPCC to be significant compared to other petrochemical processes. Facilities producing other types of petrochemicals are not subject to proposed 40 CFR part 98, subpart X of this reporting rule but may be subject to 40 CFR part 98, subpart C, General Stationary Fuel Combustion Sources, or other subparts.

There are 88 facilities operating petrochemical processes in the U.S., and 9 of these operate either two or three types of petrochemical processes (e.g., ethylene and ethylene oxide). We estimate petrochemical production accounts for approximately 55 million metric tons CO_2e.

Total GHG emissions relevant to the petrochemical industry primarily include process-based emissions and emissions from combustion sources. Process-based emissions may be released to the atmosphere from process vents, equipment leaks, aerobic biological treatment systems, and in some cases, combustion source vents. CH_4 may also be a process-based emission from processes where CH_4 is a feedstock (e.g., when methanol is produced from synthesis gas that is derived from reforming natural gas, some CH_4 passes through the process without being converted and is emitted).

Emissions from the burning of process off-gas to supply energy to the process are also process-based emissions because the organic compounds being burned are derived from the feedstock chemical. These emissions are included with other process-based emissions if the mass balance monitoring method (described in Section V.X.3 of this preamble) is used to estimate process-based emissions, but they are included with combustion source emissions if CEMS are used to measure emissions from all stacks. Combustion source emissions include CO_2, CH_4, and N_2O emissions from combustion of either supplemental fuel alone (under the mass balance option) or combustion of both supplemental fuels and process off-gas (under the CEMS option). This difference in approach for emissions from the combustion of off-gas is necessary to avoid either double counting or not counting these emissions, particularly if off-gas and supplemental fuel are mixed in a fuel gas system.

CH_4 emissions from onsite wastewater treatment systems (if anaerobic) are another possible source of GHG emissions from the petrochemical industry, but these emissions are expected to be small because anaerobic wastewater treatment is not common at petrochemical facilities. CH_4 emissions from onsite wastewater treatment systems would be estimated and reported according to the proposed procedures in proposed 40 CFR part 98, subpart II.

The ratio of process-based emissions to supplemental fuel combustion emissions varies among the various petrochemical processes. For example, process-based emissions dominate for acrylonitrile, ethylene, and ethylene oxide processes. Both process-based and supplemental fuel combustion emissions are important for carbon black and methanol processes. Emissions from supplemental fuel combustion predominate for ethylene dichloride processes. Equipment leak and wastewater emissions are both estimated to be less than 1 percent of the total emissions from petrochemical production.

For further discussion see the Petrochemical Production TSD (EPA-HQ-OAR–2008–0508–024).

2. Selection of Reporting Threshold

We propose that every facility which includes within its boundaries methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, or carbon black production be subject to the requirements of this proposed rule.

In developing the proposed threshold for petrochemical facilities, we considered emissions-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. Table X–1 of this preamble illustrates the emissions and number of facilities that would be covered under the four threshold options.

TABLE X–1. THRESHOLD ANALYSIS FOR PETROCHEMICAL PRODUCTION

Threshold level metric tons CO_2e/yr	Total National Emissions, metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number of facilities	Percent
1,000	54,830,000	88	54,830,000	100	88	100
10,000	54,830,000	88	54,820,000	99.98	87	98.9
25,000	54,830,000	88	54,820,000	99.98	87	98.9
100,000	54,830,000	88	54,440,000	99.7	84	95.5

The emissions presented in Table X–1 of this preamble are the total emissions associated solely with the production of methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, or carbon black, not the total emissions from petrochemical facilities. An estimate of the total emissions was difficult to develop because many of these facilities contain multiple source categories. For example, some petrochemical operations occur at petroleum refineries. Other petrochemical manufacturing facilities produce chemicals such as ammonia or hydrogen that are also subject to reporting. In addition, numerous chemical manufacturing facilities produce other chemicals in addition to one or more of the petrochemicals; these facilities may have combustion sources associated with these other chemical manufacturing processes that are separate from the combustion sources for petrochemical processes.

Based on this analysis, 87 of the 88 petrochemical facilities have estimated combustion and process-based GHG emissions that exceed the 25,000 metric tons CO_2e/yr threshold, and 1 facility has estimated GHG emissions less than 10,000 metric tons CO_2e/yr. The facility with estimated GHG emissions less than 10,000 metric tons CO_2e/yr is a carbon black facility. Considering that the threshold analysis did not include all types of emissions occurring at petrochemical facilities, and the large percentage of facilities that were above the various thresholds even when these emissions were excluded, EPA proposes that all facilities producing at least one of the petrochemicals report. This would simplify the rule and likely achieve the same result as having a 25,000 metric tons CO_2e threshold.

For a full discussion of the threshold analysis, please refer to the Petrochemical Production TSD (EPA–HQ–OAR–2008–0508–024). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We reviewed existing domestic and international GHG monitoring guidelines and protocols including the 2006 IPCC Guidelines and DOE 1605(b). Protocols included methods for both CO_2 and CH_4. From this review, we developed the following three options that share a number of features with the three Tiers presented by IPCC:

Option 1. Apply default emission factors based on the type of process and site-specific activity data (e.g., measured or estimated annual production rate). This option is the same as the IPCC Tier 1 approach.

Option 2. Perform a carbon balance to estimate CO_2 emissions derived from carbon in feedstocks. Inputs to the carbon balance would be the flow and carbon content of each feedstock, and outputs would be the flow and carbon content of each product/byproduct. Organic liquid wastes that are collected for shipment offsite would also be considered an output in the carbon balance. The difference between carbon inputs and outputs is assumed to be CO_2 emissions. This includes all unconverted CH_4 feedstock that is emitted. In addition, all CO_2 that is recovered for sale or other use is considered an emission for the purposes of reporting for petrochemical processes. However, the volume of CO_2 would be accounted for separately using the procedures in proposed 40 CFR part 98, subpart PP.

This option would require continuous monitoring of liquid and gaseous flows using flow meters, measurement of solid feedstock and product flows using scales or other weighing devices, and determination of the carbon content of each feedstock and product/byproduct at least once per week. Supplemental fuel is not considered to be a feedstock because these fuels do not mix with process fluids (except in the furnace of a carbon black process) and would be calculated consistent with the monitoring methods in proposed 40 CFR part 98, subpart C.

In addition to using the carbon balance to estimate process-based CO_2 emissions, this option would require the petrochemical facility owner to estimate CO_2, CH_4, and N_2O emissions from the combustion of supplemental fuels using the monitoring methods in proposed 40 CFR part 98, subpart C, and to estimate CH_4 emissions from onsite wastewater treatment using the monitoring methods in proposed 40 CFR part 98, subpart II.

Option 3. Direct and continuous measurement of CO_2 emissions from each stack (process vent or combustion source) using a CEMS for CO_2 concentration and a stack gas volumetric flow rate monitor.

This option also would require the petrochemical facility owner to use engineering analyses to estimate flow and carbon content of gases discharged to flares using the same procedures described in Section V.Y.3 of this preamble for petroleum refineries. Just as at petroleum refineries, flares at petrochemical facilities are used to control a variety of emissions releases. In addition, the flow and composition of gas flared can change significantly. Therefore, the Agency is proposing the same methodology for petrochemical flares as for flares at petroleum refineries. Please refer to the petroleum refineries section (Section V.Y.3 of this preamble) for a discussion of the rationale for these procedures.

We request comment on this approach as well as on descriptions of differences in operating conditions for flares at petrochemical facilities and refineries that would warrant specification of different methodologies for estimating emissions.

In addition to measuring CO_2 emissions from process vents and estimating CO_2 emissions from flares, this option would require the petrochemical facility owner to calculate CH_4 and N_2O emissions from combustion sources using the monitoring methods in proposed 40 CFR part 98, subpart C, and to calculate CH_4 emissions from onsite wastewater treatment systems using the monitoring methods in proposed 40 CFR part 98, subpart II.

Proposed Options. Under this proposed rule, if you operate and maintain an existing CEMS that measures total CO_2 from process vents and combustion sources, you would be required to follow requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from your facility. In such a circumstance, you also would be required to estimate CO_2, CH_4 and N_2O emissions from flares.

If you do not operate and maintain an existing CEMS that measures total CO_2 from process vents and combustion sources for your facility, the proposed rule permits the use of either Options 2 or 3 since they account for process-based emissions, combustion source emissions, and wastewater treatment system emissions. Process-based CO_2 emissions are estimated using procedures in proposed 40 CFR part 98, subpart X; combustion emissions (CO_2, CH_4, and N_2O) and wastewater emissions (CH_4) are calculated using methods in proposed 40 CFR part 98, subparts C and II, respectively. As discussed earlier, emissions from combustion of process off-gas are calculated with other process-based emissions (only CO_2 emissions) under Option 2, but they are estimated using methods for combustion sources under Option 3 (CO_2, CH_4, and N_2O emissions). Option 2 offers greater flexibility and a lower cost of compliance than Option 3. However it also has a higher measurement uncertainty.

Option 3 is expected to have the lowest measurement uncertainty. However, using CEMS to monitor all emissions at petrochemical facilities would be relatively costly. For emissions estimates produced using Option 2, the uncertainty in these estimates is expected to be relatively low for most petrochemical processes. For ethylene dichloride and ethylene processes, the uncertainty of the carbon balance approach may be higher since it is influenced by the measurements of inputs and outputs at the facility and the percentage of carbon in the final product. Uncertainty may be high where the percentage of carbon in the product is close to 100 percent (since subtracting one large number for process output from another large number for process input results in relatively large uncertainty in the difference, even if the uncertainty in the two large numbers is low). For the petrochemical processes, we have decided that Option 2 is reasonable for purposes of this proposed rulemaking. However, direct measurement may provide improved emissions estimates.

Option 1 was not proposed because the use of default values and lack of direct measurement results in a high level of uncertainty. These default approaches would not provide site-specific estimates of emissions that would reflect differences in feedstocks, operating conditions, catalyst selectivity, thermal/energy efficiencies, and other differences among plants. 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 request comment on how to improve the emission estimates developed using the carbon balance approach (Option 2), including whether the uncertainty in the estimated emissions can be reduced (and if so, by how much), the advantages, disadvantages, types and frequency of other measurements that could be required, costs of alternatives, how the uncertainty of alternatives is estimated, and the QA procedures that should be followed to assure accurate measurement. For further discussion of our assumptions on the uncertainty of emissions estimates see the Petrochemical Production TSD (EPA–HQ–OAR–2008–0508–024).

Additional Issues and Requests for Comments. EPA is interested in public comment on four additional issues.

Fugitive emissions from petrochemical production facilities have been of environmental interest primarily because of the VOC emissions. As noted above, we have concluded that fugitive CO_2 and CH_4 emissions contribute very little to the overall GHG emissions from the petrochemical production sector, and non-CH_4 hydrocarbon losses assumed to be CO_2 emissions overstate the emissions only slightly. Consequently, the Agency is not proposing that fugitive emissions be reported.

Second, Option 2 assumes all carbon entering the process is released as CO_2 and does not account for potential CH_4 emissions, nor are N_2O emissions estimated in this approach. EPA believes CH_4 and N_2O emissions are small.

Third, EPA is aware that a limited number of petrochemical facilities may produce petrochemicals as well as one or more other chemicals that are part of another source category (e.g.production of hydrogen for sale and the petrochemical methanol from synthesis gas created by steam reforming of CH_4). We consider these ''integrated processes'' and request comment on whether the procedures for the affected source categories are clear and adequate for addressing emissions from integrated facilities.

Fourth, we are proposing several methods for measuring the volume, carbon content and composition of feedstocks and products. There may be additional peer-reviewed and published measurement methodologies.

Public comment on each of these four issues is welcomed. Where applicable, supporting data and documentation on how emissions should be included, and if so, how these emissions can be estimated, including the advantages, disadvantages, types and frequency of measurements that could be required, costs of alternatives, how the uncertainty of alternatives is estimated, and the QA procedures that should be followed to assure accurate measurement.

4. Selection of Procedures for Estimating Missing Data

The missing data procedures in proposed 40 CFR part 98, subpart C for combustion units are proposed for facilities that use CEMS to estimate emissions from both combustion sources and process vents. Similarly, if the mass balance option is used, the same procedures that apply to missing data for fuel measurements in proposed 40 CFR part 98, subpart C would also apply to missing flow and carbon content measurements of feedstocks and products. Specifically, the substitute data value for missing carbon content, CO_2 concentration, or stack gas moisture content values would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. The substitute data value for missing feedstock, product, or stack gas flows would be the best available estimate based on all available process data.

5. Selection of Data Reporting Requirements

Where CEMS are used, the reporting requirements specified in proposed 40 CFR part 98, subpart C would apply. Where the carbon balance method is used, we propose that the following information be reported: Identification of the process, annual CO_2 emissions for each type of petrochemical produced and each process unit, the methods used to determine flows and carbon contents, the emissions calculation methodology, quantity of feedstocks consumed, quantity of each product and byproduct produced, carbon contents of each feedstock and product, information on the number of actual versus substitute data points, and the quantity of CO_2 captured for use. In addition, owners and operators would report information related to all equipment calibrations; measurements, calculations, and other data; certifications; and any other QA procedures used to assess the uncertainty in emissions estimates.

The data to be reported under the proposed rule form the basis of the emissions calculations and are needed for us to understand the emissions data and verify reasonableness of the reported emissions. The Agency requests comment on the types of QA procedures that are most commonly conducted or recommended and the information that would be most useful in assessing uncertainty of the emissions estimates.

6. Selection of Records That Must Be Retained

Petrochemical production facilities would be required to keep records of the information specified in proposed 40 CFR 98.3, as applicable. Under the carbon balance option, a facility also would be required to keep records of all feedstock and product flows and carbon content determinations. If a petrochemical production facility complies with the CEMS option, the additional records for CEMS listed in proposed 40 CFR 98.37 would also be required for all CEMS, including CEMS on process stacks that are not associated with combustion sources. These records document values that are directly used to calculate the emissions that are reported and are necessary to enable verification that the GHG emissions monitoring and calculations were done correctly.

Y. Petroleum Refineries

1. Definition of the Source Category

Petroleum refineries are facilities engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen), or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. There are 150 operating petroleum refineries in the U.S. and its territories. Emissions from petroleum refineries account for approximately 205 million metric tons CO_2e, representing approximately 3 percent of the U.S. nationwide GHG emissions. Most of these emissions are CO_2 emissions from fossil fuel combustion. While the U.S. GHG Inventory does not separately report onsite fuel consumption at petroleum refineries, it estimates that approximately 0.6 million metric tons CO_2e of CH_4 are emitted as fugitives per year from petroleum refineries in the U.S. Most CO_2 emissions at a refinery are combustion-related, accounting for approximately 67 percent of CO_2 emissions at a refinery.

The combustion of catalyst coke in catalyst cracking units is also a significant contributor to the CO_2 emissions (approximately 25 percent) from petroleum refineries. Combustion of excess or waste fuel gas in flares contributes approximately 2 percent of the refinery's overall CO_2 emissions. As such, the Agency proposes that the emissions from these sources must be reported.

Process emissions of CO_2 also occur from the sulfur recovery plant, because the amine solutions used to remove hydrogen sulfide (H_2S) from the refinery's fuel gas adsorb CO_2. The stripped sour gas from the amine adsorbers is fed to the sulfur recovery plant; the CO_2 contained in this stream is subsequently released to the atmosphere. Most refineries have on-site sulfur recovery plants; however, a few refineries send their sour gas to neighboring sulfur recovery or sulfuric acid production facilities. The quantity of CO_2 contained in the sour gas sent for off-site sulfur recovery operations is considered an emission under this regulation.

There are a variety of GHG emission sources at the refinery, which include: Asphalt blowing, delayed coking unit depressurization and coke cutting, coke calcining, blowdown systems, process vents, process equipment leaks, storage tanks, loading operations, land disposal, wastewater treatment, and waste disposal. To fully account for the refinery's GHG emissions, we propose that the emissions from these sources must also be reported.

Based on the emission sources at petroleum refineries, GHGs to report under proposed 40 CFR part 98, subpart Y are limited to CO_2, CH_4, and N_2O. Table Y–1 of this preamble summarizes the GHGs to be reported by emission source at the refinery.

TABLE Y–1. GHGS TO REPORT UNDER 40 CFR PART 98, SUBPART Y

Emission source	GHGs to report	Subpart of proposed 40 CFR part 98 where emissions reporting methodologies addressed
Stationary combustion sources	CO_2, CH_4, and N_2O	Subpart C.
Coke burn-off emissions from catalytic cracking units, fluid coking units, catalytic reforming units, and coke calcining units.	CO_2, CH_4, and N_2O	Subpart Y.
Flares	CO_2, CH_4, and N_2O	Subpart Y.
Hydrogen plant vent	CO_2 and CH_4	Subpart P.
Petrochemical processes	CO_2 and CH_4	Subpart X.
Sulfur recovery plant, on-site and off-site	CO_2	Subpart Y.
On-site wastewater treatment system	CO_2 and CH_4	Subpart II.
On-site land disposal unit	CH_4	Subpart HH.
Fugitive Emissions	CO_2, CH_4, and N_2O	Subpart Y.
Delayed coking units	CH_4	Subpart Y.

2. Selection of Reporting Threshold

Four options were considered as reporting thresholds for petroleum refineries. Table Y–2 of this preamble illustrates the emissions and number of facilities that would be covered under the four options.

TABLE Y–2. THRESHOLD ANALYSIS FOR PETROLEUM REFINING

Option/threshold level	Emissions covered		Facilities covered	
	Million metric tons CO_2e/year	Percent	Number	Percent
1,000 metric tons CO_2e	204.75	100	150	100
10,000 metric tons CO_2e	204.74	99.995	149	99.3
25,000 metric tons CO_2e	204.69	99.97	146	97.3
100,000 metric tons CO_2e	203.75	99.51	128	85.3

We are proposing that all petroleum refineries should report. This approach would ensure full reporting of emissions, affect an insignificant number of additional sources compared to the 25,000 metric tons CO_2e threshold, and would add minimal additional burden to the reporting facilities. All U.S. refineries must report their fuel consumption to the EIA, so there is limited additional burden to estimate their GHG emissions. Furthermore, due to the importance of the petroleum refining industry to our nation's energy needs as well as the overall U.S. GHG inventory, it is important to obtain the best information available for this source category. We estimate that 4 refineries did not exceed a reporting threshold of 25,000 metric tons CO_2e in 2006 and invite public comment on this matter.

For a full discussion of the threshold analysis, please refer to the Petroleum Refineries TSD (EPA–HQ–OAR–2008–0508–025). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We considered monitoring methods that are used or recommended for use from several sources including international groups, U.S. agencies, State agencies, and petroleum refinery trade organizations. For most emission sources, three general levels of monitoring options were evaluated: (1) Use of engineering calculations and/or default factors; (2) monitoring of process parameters (such as fuel consumption quantities and carbon content); and (3) direct emission measurement using CEMS for all emissions sources at a refinery.

Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

For facilities that do not currently have CEMS that meet the requirements outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, the proposed monitoring method is Option 2. Option 2 accounts for process-related CO_2 emissions. Simplified methods for estimating fugitive CH_4 emissions are provided below. Refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CH_4 and N_2O emissions.

You would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart HH to estimate emissions from landfills, proposed 40 CFR part 98, subpart II to estimate emissions from wastewater and proposed 40 CFR part 98, subpart P to estimate emissions from hydrogen production (non-merchant hydrogen plants only).

Specifically, for fluid catalytic cracking units and fluid coking units that already have CEMS in place, we propose to require refineries to report CO_2 emissions using these CEMS. For the sources that contribute significantly to the overall GHG emissions from the refinery, as defined below, we propose monitoring of process parameters (Option 2). The Agency requests comment on the feasibility of allowing smaller emission sources at the refinery to employ less certain (Option 1) methods as a way to reduce the costs and burden of measurement and verification under this proposed rule. Providing this flexibility would result in lower costs but greater uncertainty around some portions of a facility's emissions estimates.

The selected monitoring methods for this proposed rule generally follow those used in other reporting rules as well as those recommended in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies* for the Oil and Gas Industry (hereafter referred to as ''the API Compendium''). More detail regarding the selection of the proposed monitoring options for specific emission sources follows.

Coke burn-off. The proposed methods for estimating GHG emissions from coke burn-off in the catalytic cracking unit, fluid coking unit, and catalytic reforming unit generally follow the methods presented in the API Compendium for coke burn-off. Fluid catalytic cracking units and fluid coking units are large CO_2 emission sources, accounting for over 25 percent of the GHG emissions from petroleum refineries. Most of these units are expected to monitor gas composition for process control or for compliance with applicable monitoring provisions under 40 CFR part 60, subparts J and Ja and under 40 CFR part 63, subpart UUU. Given the magnitude of the GHG emissions from catalytic cracking units and fluid coking units, direct monitoring for CO_2 emissions (i.e., continuous monitoring of CO_2 concentration and flow rate at the final exhaust stack) is believed to provide greater certainty in the emission estimate. However, compositional analysis monitoring in the regenerator or fluid coking burner exhaust vent prior to the combustion of other fuels (such as auxiliary fuel fired to a CO boiler) may be used when direct monitoring for CO_2 emissions is not already employed. An equation is provided in the rule for calculating the vent stream flow rate based on the compositional analysis data rather than requiring a continuous flow monitor; this equation is allowed in other petroleum refinery rules (40 CFR part 60, subparts J and Ja; 40 CFR part 63, subpart UUU) as an alternative to continuous flow monitoring.

An engineering approach for estimating coke burn-off rates and calculating CO_2 emissions using default carbon content for petroleum coke was considered. However, as most catalytic cracking units already must have the compositional monitors in-place due to other petroleum refinery rules and because catalytic cracking unit coke burn-off is a significant contributor to the overall GHG emissions from petroleum refineries, we are not proposing an engineering calculation for the catalytic cracking units. However, comment is requested on the engineering methods available to estimate coke burn-off rates, the uncertainty of the methods, and the measurements or parameters and enhanced QA that can be used to verify the engineering emission estimates and their certainty.

The amount of coke burned in catalytic reforming units is estimated to be about 1 percent of the amount of coke burned in catalytic cracking units or fluid coking units; therefore, a simplified method is provided for estimating coke burn-off emissions for catalytic reforming units that do not monitor gas composition in the coke burn-off exhaust vent.

Flares. Specific monitoring provisions are provided for flares. As the composition of gas flared can change significantly, we considered proposing continuous flow and composition monitors (or heating value monitors) on all flares. For example, in California, both the South Coast and Bay Area Air Quality Management Districts require these monitors for refineries located in their districts. However, a significant fraction of flares is not expected to have these monitoring systems installed. Further, since flares are projected to contribute only about 2 percent of a typical refinery's CO_2 emissions, it would be costly to improve the monitoring systems for flare emission estimates. The use of the default CO_2 emission factor for refinery fuel gas was also considered. The default emission factor is expected to be reasonable during normal refinery operations, but is highly uncertain during periods of start-up, shutdown, or malfunction. Consequently, a hybrid method is proposed that allows the use of a default CO_2 emission factor for refinery fuel gas during periods of normal refinery operations and specific engineering analysis of GHG emissions during periods of high flare volumes associated with start-up, shutdown, or malfunction. As with stationary combustion sources, default emission factors for refinery gas are proposed to calculate CH_4 and N_2O emissions from flares.

Sulfur Recovery Plants. For sulfur recovery plants at the petroleum refinery and for instances where sour gas is sent off-site for sulfur recovery, direct carbon content measurement in the sour gas feed to the sulfur recovery plant is the preferred monitoring approach. However, a site-specific or default carbon content method is also provided. It is anticipated that monitoring systems would be in place at most refineries, as monitoring of the sour gas feed is important in the operation of the sulfur recovery plant. The monitoring data for carbon content and flow rate must be used if they are available. The alternative default carbon content method is provided because the emissions from this source are relatively small, 1 to 2 percent for a given facility, and because only small, non-Claus sulfur recovery plants are not expected to monitor the flow and composition of the sour gas. We are proposing that only CO_2 emissions would need to be reported for the sulfur recovery plant process-related emissions.

Coke Calcining. For coke calcining units at the petroleum refinery, direct CO_2 measurement is the preferred monitoring approach. However, a carbon balance approach is proposed similar to the approach included in *The Aluminum Sector Greenhouse Gas Protocol*[83] for units that do not have CEMS. This is because coke calcining is a small source of GHG emissions, less than 1 percent for a given facility. CH_4 and N_2O emissions are calculated from the coke calcining CO_2 process emissions using the default emission factors for petroleum coke combustion (the same equations as proposed for calculating CH_4 and N_2O emissions from coke burn-off).

Process Vents not Otherwise Specified. For process vents other than those discussed elsewhere in this section of the preamble, either process knowledge or measurement data can be used to calculate the GHG emissions. Due to other regulations affecting petroleum refineries, only a few, small process vents are expected to be present at most refineries. As such, these small vents do not warrant requiring the use of CEMS to quantify emissions. Process vent emissions are expected to be predominately CO_2 or CH_4, but N_2O

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[83] International Aluminum Institute. 2006. The Aluminum Sector Greenhouse Gas Protocol (Addendum to the WRI/WBCSD Greenhouse Gas Protocol). pp. 31–32. Available at: *http://www.world-aluminium.org/Downloads/Publications/Download.*

emissions, if present, are also to be reported.

Other Sources. Due to the small (less than 1 percent) contribution of other emissions sources at the refinery that make up the total GHG emissions from the facility, very simple methods are proposed to estimate these other emissions sources. Alternative methods are provided so that facilities can provide more detailed estimates if desired. For example, a refinery may estimate CH_4 emissions from individual tanks using EPA's TANKS model, if desired, or apply a default emission factor to the facility's overall throughput. Simple emission factor approaches are provided for asphalt blowing, delayed coking unit depressurization and coke cutting, blowdown systems, process equipment leaks, storage tanks, and loading operations.

For further discussion of this source category and monitoring of its emissions, see the Petroleum Refineries TSD (EPA–HQ–OAR–2008–0508–025).

4. Selection of Procedures for Estimating Missing Data

In those cases where you use direct measurement by a CO_2 CEMS, the missing data procedures would be the same as the Tier 4 requirements described for general stationary fuel combustion sources in proposed 40 CFR part 98, subpart C. Missing data procedures are also specified, consistent with proposed 40 CFR part 98, subpart C, for heat content, carbon content, fuel molecular weight, gas and liquid fuel flow rates, stack gas flow rates, and compositional analysis data (CO_2, CO, O_2, CH_4, N_2O, and stack gas moisture content, as applicable). Generally, the average of the data measurements before and after the missing data period would be used to calculate the emissions during the missing data period.

5. Selection of Data Reporting Requirements

The reporting requirements for combustion sources other than those associated with coke burn-off directly refer to those in proposed 40 CFR part 98, subpart C, General Stationary Fuel Combustion Sources. For other sources, we propose to report the identification of the source, throughput of the source (if applicable), the calculation methodology used, the total GHG emissions for the source, and the quantity of CO_2 captured for use and the end use, if known. A list of the specific GHG emissions reportable for each emission source is provided in Table Y–1 of this preamble.

The reporting requirements consist of actual GHG emission values as well as values that are directly used to calculate the emissions and are necessary in order to verify that the GHG emissions monitoring and calculations were done correctly. As there are high uncertainties associated with many of the ancillary emission sources at the refinery, separate reporting of the emissions for these separate sources is needed to fully understand the importance and variability of these ancillary emission sources. A complete list of information to report is contained in proposed 40 CFR 98.256.

6. Selection of Records That Must Be Retained

The recordkeeping requirements in the general provisions of proposed 40 CFR part 98 apply for petroleum refineries. Specifically, refineries would be required to keep all records specified in proposed 40 CFR part 98, subpart A and summarized in Section III.E of this preamble. In addition, records of the data required to be monitored and reported under proposed 40 CFR part 98, subpart Y would be retained. If CEMS are used to quantify the GHG emissions, you would be required to keep additional records specified in proposed 40 CFR part 98, subparts A and Y. These records consist of values that are directly used to calculate the emissions and are necessary to enable verification that the GHG emissions monitoring and calculations were done correctly.

Z. Phosphoric Acid Production

1. Definition of the Source Category

Phosphoric acid is a common industrial product used to manufacture phosphate fertilizers. Phosphoric acid is a product of the reaction between phosphate rock and, typically, sulfuric acid (H_2SO_4). A byproduct called calcium sulfate ($CaSO_4$), or gypsum, is formed when calcium from the phosphate rock reacts with sulfate. Most companies in the U.S. use a dihydrate process in which two molecules of water (H_2O) are produced per molecule of gypsum ($CaSO_4 \cdot 2\ H_2O$ or calcium sulfate dihydrate).

Additionally, a second reaction occurs in which the limestone ($CaCO_3$) present in the phosphate rock reacts with sulfuric acid (H_2SO_4) releasing CO_2. The amount of carbon in the phosphate rock feedstock varies depending on the region in which it was mined.

National emissions from phosphoric acid production facilities were estimated to be 3.8 million metric tons CO_2e in 2006. These emissions include both process-related emissions (CO_2) and on-site stationary combustion emissions (CO_2, CH_4 and N_2O) from 14 phosphoric acid production facilities across the U.S. Process-related emissions account for 1.2 million metric tons CO_2e, or 30 percent of the total, while on-site stationary combustion emissions account for the remaining 2.7 million metric tons CO_2e emissions.

The phosphoric acid production industry has many production sites that are integrated with mines; notably, three facilities import phosphate rock from Morocco.

For additional background information on phosphoric acid production, please refer to the Phosphoric Acid Production TSD (EPA–HQ–OAR–2008–0508–026).

2. Selection of Reporting Threshold

In developing the threshold for phosphoric acid production, we considered emissions-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 per year. Table Z–1 of this preamble illustrates the emissions and number of facilities would not be impacted under these various applicability thresholds.

TABLE Z–1. THRESHOLD ANALYSIS FOR PHOSPHORIC ACID PRODUCTION

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	3,838,036	14	3,838,036	100	14	100
10,000	3,838,036	14	3,838,036	100	14	100
25,000	3,838,036	14	3,838,036	100	14	100
100,000	3,838,036	14	3,838,036	100	14	100

There is no proposed threshold for reporting emissions from phosphoric acid production. Even at a 100,000 metric tons CO_2e threshold, all emissions would be covered, and all facilities would be required to report. Having no threshold would simplify the rule and avoid any burden for unnecessary calculations to determine if a threshold is exceeded. Therefore, we propose that all phosphoric acid production facilities report.

For a full discussion of the threshold analysis, please refer to the Phosphoric Acid Production TSD (EPA–HQ–OAR–2008–0508–026). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

The methodology for estimating process-related emissions from phosphoric acid production is based on the U.S. GHG Inventory method discussed further in the Phosphoric Acid Production TSD (EPA–HQ–OAR–2008–0508–026). Most domestic and international GHG monitoring guidelines and protocols, such as the 2006 IPCC Guidelines do not provide estimation methodologies for process-related emissions from phosphoric acid production.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

If you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C, we propose that facilities estimate process-related CO_2 emissions by determining the amount of inorganic carbon input to the process through measurement of the inorganic carbon content of the phosphate rock and multiplying by the amount (mass) of phosphate rock used to manufacture phosphoric acid. Refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CH_4 and N_2O emissions.

In order to assess the composition of the inorganic carbon input, we assume that vertically integrated phosphoric acid production facilities already have the necessary equipment on-site for conducting chemical analyses of the inorganic carbon weight fraction of the phosphate rock and that this analysis is conducted on a routine basis at facilities. Facilities importing rock from Morocco would send rock samples off-site for composition analysis. The inorganic carbon content would be determined on a per-batch basis. Multiplying the inorganic carbon content by the amount (mass) of phosphate rock processed and by the molecular weight ratio of CO_2 to inorganic carbon (44/12) yields the estimate of CO_2 emissions. This calculated value should be recorded monthly based on the most recent batch of phosphate rock received. The monthly emissions for each phosphoric acid process line are then summed to obtain the annual emissions to be included in the report.

The various approaches to monitoring GHG emissions are elaborated in the Phosphoric Acid Production TSD (EPA–HQ–OAR–2008–0508–026).

4. Selection of Procedures for Estimating Missing Data

The likelihood for missing data is low, as businesses closely track their purchase of production inputs. The Phosphoric Acid NSPS (40 CFR part 60, subpart T) requires continuous monitoring of phosphorus-bearing material (rock) to process. This requirement, along with the fact that the facility would closely monitor production inputs, results in low likelihood of missing data. Additionally, only 3 facilities within the U.S. are not vertically integrated with mines and may lack the necessary equipment to measure the inorganic carbon weight percent of the rock. Therefore, no missing data procedures would apply to CO_2 emission estimates from wet-process phosphoric acid production facilities because inorganic carbon test results and monthly production data should be readily available. Therefore, 100 percent data availability would be required.

5. Selection of Data Reporting Requirements

We propose that facilities report total annual CO_2 emissions from each wet-process phosphoric acid productionline, as well as any stationary fuel combustion emissions. In addition, we propose that facilities report their annual average phosphate rock consumption, percent of inorganic carbon in the phosphate rock consumed, annual phosphoric acid production and concentration and annual phosphoric acid capacity. These data are used to calculate emissions. They are needed for us to understand the emissions data and assess the reasonableness of the reported emissions. A full list of data to be reported is included in proposed40 CFR part 98, subparts A and Z.

6. Selection of Records That Must Be Retained

In addition to the data reported, we propose that facilities maintain records of inorganic carbon content chemical analyses on each batch of phosphate rock and monthly phosphate rock consumption (by the origin of the phosphate rock). These records provide values that are directly used to calculate the emissions that are reported and are necessary to allow determination of whether the GHG emissions monitoring and calculations were done correctly.

A full list of records that must be retained on-site is included in proposed 40 CFR part 98, subparts A and Z.

AA. Pulp and Paper Manufacturing

1. Definition of the Source Category

The pulp and paper source category consists of over 5,000 facilities engaged in the manufacture of pulp, paper, and/or paperboard products primarily from wood material. However, less than 10 percent of these facilities are expected to meet the applicability thresholds of this proposed rule. The approximately 425 facilities that the proposed rule is expected to cover mainly consist of facilities that include pulp, paper and paperboard facilities that operate fossil fuel-fired boilers in addition to operating other sources of GHG emissions (e.g., biomass boilers, lime kilns, onsite landfills, and onsite wastewater treatment systems).[84]

Greenhouse gas emissions from the pulp and paper source category are predominantly CO_2 with smaller amounts of CH_4 and N_2O. The pulp and paper GHG emissions include biomass-derived CO_2 emissions from using the biomass generated on site as a byproduct (e.g., bark, other wood waste, spent pulping liquor). For example, kraft pulp and paper facilities are likely to generate byproduct biomass fuel while the majority of the onsite energy for non-integrated paper facilities and 100 percent recycled paper facilities is likely to be generated from fossil fuel-fired boilers because these facilities do not generate byproduct biomass fuel.

Table AA–1 of this preamble lists the GHG emission sources that may be

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[84] This estimate is based on a survey of pulp and paper mills conducted by the National Council for Air and Stream Improvement that operated stationary combustion units in 2005. See: National Council of Air and Stream Improvement Special Report No. 06–07. December 2006.

found at pulp and paper facilities, the type of GHG emissions that are required to be reported, and where the reporting methodologies are found in proposed 40 CFR part 98.

TABLE AA–1. GHG EMISSION SOURCES AT PULP, PAPER, AND PAPERBOARD FACILITIES

Emissions source	GHG emissions	Subpart of 40 CFR part 98 where emissions reporting methodologies addressed
General Stationary Fuel Combustion	CO_2, CH_4, N_2O, biomass-CO_2.	Subpart C.
Makeup Chemicals ($CaCO_3$, Na_2CO_3)	CO_2	Subpart AA.
Onsite industrial landfills	CH_4	Subpart HH.
Wastewater treatment	CH_4	Subpart II.

The method presented in this section of the preamble is to account for the use of make-up chemicals (e.g., sodium sulfate, calcium carbonate, sodium carbonate) that are added into the recovery loop (e.g., with the spent pulping liquor) at a pulp and paper facility to replace the small amounts of sodium and calcium that are lost from the recovery cycle at kraft and soda facilities. When carbonates are added, the carbon in these make-up chemicals, which can be derived from biomass or mineral sources, is emitted as CO_2 from recovery furnaces and lime kilns. In cases where the carbon is mineral-based, emissions of CO_2 would contribute to GHG emissions.

Affected facilities would be required to report total GHG emissions on a facility-wide basis for all source categories for which methods are presented in proposed 40 CFR part 98.

2. Selection of Reporting Threshold

For the pulp and paper source category, the Agency proposes a GHG reporting threshold of 25,000 metric tons CO_2e, which would include the vast majority of GHG emissions from the pulp and paper source category.[85]

As described in proposed 40 CFR part 98, subpart A, biomass-derived CO_2 emissions should not be taken into consideration when determining whether a facility exceeds the 25,000 metric tons CO_2e threshold.

In evaluating potential thresholds for the pulp and paper source category, we considered emissions-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. The threshold analysis focuses on the most significant sources of GHG emissions in the pulp and paper industry, specifically facilities that make pulp, paper and paperboard and operate fossil fuel-fired boilers. Therefore, of the 5,000 facilities associated with this industry, only 425 were included in the analysis. Table AA–2 of this preamble illustrates that the various thresholds do not have a significant effect on the amount of emissions that would be covered.

For a full discussion of the threshold analysis, please refer to the Pulp and Paper Manufacturing TSD (EPA–HQ–OAR–2008–0508–027). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

TABLE AA–2. REPORTING THRESHOLDS FOR PULP AND PAPER SECTOR

Threshold level metric tons CO_2e	Total national emissions (metric tons CO_2e)	Total number of U.S. facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	57,700,000	425	57,700,000	100	425	100
10,000	57,700,000	425	57,700,000	100	425	100
25,000	57,700,000	425	57,700,000	100	425	100
100,000	57,700,000	425	57,527,000	99.7	410	96

3. Selection of Proposed Monitoring Methods

a. Calculation Methods Selected

Refer to proposed 40 CFR part 98, subparts C, HH, and II for monitoring methods for general stationary fuel combustion sources, landfills, and industrial wastewater treatment occurring on-site at pulp and paper facilities. This section of the preamble includes monitoring methods for calculating and reporting makeup chemicals at pulp and paper facilities. Additional details on the proposed monitoring options are elaborated in the Pulp and Paper Manufacturing TSD (EPA–HQ–OAR–2008–0508–027).

The proposed method for monitoring emissions from carbonate-based make-up chemicals used at chemical pulp facilities includes calculating the CO_2 emissions from the added $CaCO_3$ and Na_2CO_3 using emissions factors provided in the rule. The calculation assumes that the carbonate based make-up chemicals added (e.g., limestone) are pure carbonate minerals, and that all of the carbon is released to the atmosphere. If you believe that these assumptions do not represent circumstances at your facility, you may send samples of each carbonate consumed to an off-site laboratory for a chemical analysis of the carbonate weight fraction on a quarterly basis, consistent with proposed 40 CFR part 98, subpart U. You could also determine the calcination fraction for each of the carbonate-based minerals consumed, using an appropriate test method. Make-up chemical usage would be required to be determined by direct measurement of the quantity of chemical added. The chemical usage should be quantified separately for each chemical used, and

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[85] The American Forest and Paper Association estimates that the 25,000 metric tons CO_2e would include approximately 99 percent of GHG emissions from the pulp and paper source category.

the estimate should be in terms of pure $CaCO_3$ and/or Na_2CO_3. We have proposed direct measurement for quantifying the amount of makeup chemicals, consistent with the estimation of emissions from carbonates in the rest of proposed 40 CFR part 98.

For the monitoring methods detailed in proposed 40 CFR part 98, subpart C for general stationary combustion, it should be noted that biogenic CO_2 emissions from the combustion of biomass fuels are to be reported separately. Furthermore, in referring to proposed 40 CFR part 98, subpart C on general stationary combustion, we would expand upon particular details unique to a pulp and paper facility, because of the unique uses of biomass fuels. For the pulp and paper source category, biomass fuels include, but may not be limited to: (1) Unadulterated wood, wood residue, and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, wood shavings, paper pellets, and corrugated container rejects); (2) pulp and paper facility wastewater treatment system sludge; (3) vegetative agricultural and silvicultural materials, such as logging residues and bagasse; and (4) liquid biomass-based fuels such as biomass-based turpentine and tall oil. Such fuels could be combusted at a pulp and paper facility in stationary combustion units including, but not limited to, boilers, chemical recovery furnaces, and lime kilns. Proposed 40 CFR part 98, subpart C provides details on the separate reporting of the biogenic CO_2 emissions from these biomass-based fuels, and the calculation methodologies for any fossil fuels combusted, including when co-fired with biomass.

Where biomass is co-fired with fossil fuel, the appropriate methodology as required in proposed 40 CFR part 98, subpart C should be used. However, to minimize the burden on owners and operators of biomass-fired stationary combustion equipment, this proposed rule allows biogenic CO_2 emissions to be calculated using default emission factors and default HHVs used in the Tier 1 methodology.

Where available, like in the case of spent pulping liquor, we would require direct analysis of the HHV, rather than allowing the use of a default HHV. This is due to the variability in the HHV of spent pulping liquor across the industry and because a number of facilities already perform this analysis on a monthly basis. However, the proposed rule does not propose the use of default GHG emissions factors for spent pulping liquor at kraft pulp facilities. For sulfite and semichemical chemical recovery combustion units, we propose that sources conduct a monthly carbon content analysis of the spent pulping liquor for use in calculating the biomass CO_2 emissions because no default emissions factors are known to exist for these sources.

We are requesting comment on the appropriateness of today's proposed requirements for monthly measurement of spent pulping liquor HHV (kraft recovery furnaces) and monthly carbon content analysis of spent pulping liquor (sulfite and semichemical chemical recovery combustion units). We welcome data and documentation regarding the use of potential alternative methods or default emissions factors.

In addition, regarding the monitoring methods in proposed 40 CFR part 98, subpart C for general stationary combustion, the majority of biomass fuel consumed at pulp and paper mills is generated onsite, and thus, as required in proposed 40 CFR part 98, subpart C, the use of purchasing records might not be an option for these mills. As such, we are taking comment on appropriate details to be reported on volume or mass of biogenic fuel fed into stationary combustion units.

b. Other Monitoring Methods Considered

Lime kilns and calciners used in the pulp and paper source category are unique and are defined separately from lime kilns used in the commercial lime manufacturing industry because the source of the carbon in the calcium carbonate entering the kraft lime kiln is biogenic. The CO_2 emitted from lime kilns at kraft pulp facilities originates from two sources: (1) Fossil fuels burned in the kiln, and (2) conversion of calcium carbonate (or ''lime mud'') to calcium oxide during the chemical recovery process.

Although CO_2 is also liberated from the $CaCO_3$ burned in the kiln or calciner, the carbon released from $CaCO_3$ is biomass carbon that originates in wood and is included in the biogenic CO_2 emissions factor for the recovery furnace as discussed previously. The reporting of the CO_2 emissions associated with the conversion of the calcium carbonate to lime as biogenic CO_2 is consistent with the reporting requirements in other accepted protocols such as DOE 1605(b) and guidance developed for the International Council of the Forest and Paper Association. This approach has been widely accepted by the domestic and international community, including WRI/WBCSD. The IPCC does not directly state how CO_2 emissions from kraft facility lime kilns should be addressed. As biogenic process CO_2 emissions (i.e., any biogenic CO_2 emissions not associated with the combustion of biomass fuels) are not being reported in this rule, we are taking comment on whether an exception should be made for this unique case, consistent with other existing protocols as noted above.

4. Selection of Procedures for Estimating Missing Data

Refer to proposed 40 CFR part 98, subparts C, HH, and II for procedures for estimating missing data for stationary combustion, landfills, and industrial wastewater treatment occurring on-site at pulp and paper facilities.

Proposed 40 CFR part 98, subpart AA contains missing data procedures for process emissions. There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any monthly measurements are determined to be invalid. For missing spent pulping liquor flow rates, the lesser value of either the maximum fuel flow rate for the combustion unit, or the maximum flow rate that the fuel flowmeter can measure would be used. For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates).

5. Selection of Data Reporting Requirements

Refer to proposed 40 CFR part 98, subparts C, HH, and II for reporting requirements for stationary combustion, landfills, and industrial wastewater treatment occurring on-site at pulp and paper facilities.

We propose that some additional data be reported to assist in verification of estimates, checks for reasonableness, and other data quality considerations, including: Annual emission estimates presented by calendar quarters (including biogenic CO_2), total consumption of all biomass fuels and spent pulping liquor by calendar quarters, and total annual quantities of makeup chemicals (carbonates) used and by carbonate.

6. Selection of Records That Must Be Retained

Refer to proposed 40 CFR part 98, subparts C, HH, and II for recordkeeping requirements for stationary combustion, landfills, and industrial wastewater treatment occurring on-site at pulp and paper facilities.

In addition to the recordkeeping requirements for general stationary fuel combustion sources in proposed 40 CFR part 98, subpart C, we propose that the following additional records be kept to assist in QA/QC, including: GHG emission estimates by calendar quarter by unit and facility, monthly consumption total of all biomass fuels and spent pulping liquor by unit and facility, monthly analyses of spent pulping liquor HHV or carbon content, monthly and annual steam production for each biomass unit, and monthly quantities of makeup chemicals (carbonates) used.

BB. Silicon Carbide Production

1. Definition of the Source Category

Silicon carbide (SiC) is primarily an industrial abrasive manufactured from silica sand or quartz and petroleum coke. Other uses of silicon carbide include semiconductors, body armor, and the manufacture of Moissanite, a diamond substitute. The silicon carbide source category is limited to the production of silicon carbide for abrasive purposes.

CO_2 and CH_4 are emitted during the production of silicon carbide. Petroleum coke is utilized as a carbon source during silicon carbide production and approximately 35 percent of the carbon is retained within the silicon carbide product; the remaining carbon is converted to CO_2 and CH_4.

Silicon carbide process emissions totaled 109,271 metric tons CO_2e in 2006 (less than 0.002 percent of the total national GHG emissions). Of the total, process-related CO_2 emissions accounted for 91 percent (91,700 metric tons CO_2e), CH_4 emissions accounted for 9 percent (8,526 metric tons CO_2e), and on-site stationary combustion emissions accounted for less than 1 percent (9,045 metric tons CO_2e).

For additional background information on silicon carbide production, please refer to the Silicon Carbide Production TSD (EPA–HQ–OAR–2008–0508–028).

2. Selection of Reporting Threshold

In developing the reporting threshold for silicon carbide production, we considered emissions-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. Requiring all facilities to report (no threshold) was also considered. Table BB–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE BB–1. THRESHOLD ANALYSIS FOR SILICON CARBIDE PRODUCTION

Threshold level metric tons CO_2e/yr	Total national emissions (metric tons CO_2e/yr)	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	109,271	1	109,271	100	1	100
10,000	109,271	1	109,271	100	1	100
25,000	109,271	1	109,271	100	1	100
100,000	109,271	1	109,271	100	1	100

There is no proposed threshold reporting level for GHG emissions from silicon carbide production facilities. The current estimate of emissions from the known facility just exceeds the highest threshold considered. Therefore, in order to simplify the rule and avoid the need for the facility to calculate and report whether the facility exceeds the threshold value, we propose that all facilities report in this source category. Requiring all facilities to report captures 100 percent of emissions, and small temporary changes to the facility would not affect reporting requirements.

For a full discussion of the threshold analysis, please refer to the Silicon Carbide Production TSD (EPA–HQ–OAR–2008–0508–028). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Monitoring of process emissions from silicon carbide production is addressed in both domestic and international GHG monitoring guidelines and protocols (the 2006 IPCC Guidelines and U.S. GHG Inventory). These methodologies can be summarized in two different options based on measuring either inputs or output of the production process. In general, the output or production-based method is less certain, as it involves multiplying production data by emission and correction factors that are likely default values based on carbon content (*i.e.*, percentage of petroleum coke input that is carbon) assumptions. In contrast, the input method is more certain as it generally involves measuring the consumption of reducing agents and calculating the carbon contents of those reducing agents, specifically petroleum coke inputs.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS that meets the requirements outlined in proposed 40 CFR part 98, subpart C, then you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

Under this proposed rule, if you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C or where the CEMS would not adequately account for process emissions, we propose that facilities use an input based method to estimate process-related CO_2 emissions by measuring the facility-level petroleum coke consumed and applying a facility-specific emission factor derived from analysis of the carbon content in the coke. In addition, we propose that facilities use default emission factors to estimate process-related CH_4 emissions. Refer to proposed 40 CFR part 98, subpart C for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

We propose that facilities use an input-based method to estimate process-related CO_2 emissions by measuring the facility-level petroleum coke consumed and applying a facility-specific emission factor derived from analysis of the carbon content in the coke. Using the emission factor, facilities would calculate CO_2 emissions quarterly and aggregate for an annual estimate. In order to estimate carbon content, we propose that facilities request reports of the carbon content of the petroleum coke directly from the supplier or send petroleum coke samples out to a certified laboratory for chemical analysis on a quarterly basis. Any changes in the measured values would be reflected in a revised emission factor.

We assume that data on petroleum coke consumption is readily available to facilities. The measurement of production quantities is common practice in the industry and is usually measured through the use of scales or weigh belts so additional costs to the industry are not anticipated. The primary additional burden for facilities associated with this method is modifying their petroleum coke supplier contract to include an analysis of the carbon content of each delivery of petroleum coke. Alternatively, a facility can send the coke to an off-site laboratory for analysis of the carbon content by the applicable method incorporated by reference in proposed 40 CFR 98.7. We consider the additional burden of determining the carbon content of the coke raw material minimal compared to the increases in accuracy expected from the site specific emission factors.

We also considered a second method of estimating process-related CO_2 emissions that involves application of default emission factors based on the quantity of coke consumed or total silicon carbide produced. According to the 2006 IPCC Guidelines, the default CO_2 emission factors for silicon carbide production are relatively uncertain because industry scale carbide production processes differ from the stoichiometry of theoretical chemical reactions. Given the relative uncertainty of defaults, we decided not to propose existing methodologies that relied on default emission factors or default values for carbon content of materials because default approaches are inherently inaccurate for site-specific determinations. The use of default values is more appropriate for sector wide or national total estimates from aggregated activity data than for determining emissions from specific facilities.

We propose that facilities estimate process-related CH_4 emissions by using a default emission factor of 10.2 kg CH_4 per metric ton of petroleum coke consumed during silicon carbide production. This method coincides with the IPCC Tier 1 method. Direct measurement of a CH_4 emission factor was considered, but the cost of performing testing to determine this factor is too burdensome, considering that the amount of CH_4 emissions originating from silicon carbide production is less than 0.5 percent of the overall GHG emissions from this source category.

The various approaches to monitoring GHG emissions are elaborated in the Silicon Carbide Production TSD (EPA–HQ–OAR–2008–0508–028).

4. Selection of Procedures for Estimating Missing Data

It is assumed that a facility would be readily able to supply data on annual petroleum coke consumption and its carbon contents. Therefore, 100 percent data availability is required.

5. Selection of Data Reporting Requirements

We propose that facilities report the combined annual CO_2 and CH_4 emissions from the silicon carbide production processes. In addition, we propose that the following data be reported to assist in verification of calculations and estimates, checks for reasonableness, and other data quality considerations: Annual silicon carbide production, annual silicon carbide production capacity, facility-specific CO_2 emission factor, and annual operating hours. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and BB.

6. Selection of Records That Must Be Retained

In addition to the data reported, we propose that facilities maintain records of quarterly analyses of carbon content for consumed coke (averaged to an annual basis), annual consumption of petroleum coke, and calculations of emission factors. These records hold values directly used to calculate reported emissions and are necessary for future verification that GHG emissions monitoring and calculations were done correctly. A full list of records that must be maintained onsite is included in proposed 40 CFR part 98, subparts A and BB.

CC. Soda Ash Manufacturing

1. Definition of the Source Category

Soda ash (sodium carbonate, Na_2CO_3) is a raw material utilized in numerous industries including glass production, pulp and paper production, and soap production. According to the USGS, the majority of the 11 million metric tons of soda ash produced is used for glass production. In the U.S., trona (the raw material from which most American soda ash is produced) is mined exclusively in Wyoming, where five of the seven U.S. soda ash manufacturing facilities are located. Total soda ash production in 2006 was 11 million metric tons, an amount consistent with 2005 and 500,000 metric tons more than was produced in 2002. Due to a surplus of soda ash in the market, approximately 17 percent of the soda ash industry's nameplate capacity was idled in 2006.

Trona-based production methods are collectively referred to as ''natural production'' methods. ''Natural production'' emits CO_2 by calcining trona. Calcining involves placing crushed trona into a kiln to convert sodium bicarbonate into crude sodium carbonate that would later be filtered into pure soda ash.

National emissions from natural soda ash manufacturing were estimated to be 3.1 million metric tons CO_2e in 2006 or less than 0.04 percent of total emissions. These emissions include both process-related emissions (CO_2) and on-site stationary combustion emissions (CO_2, CH_4, N_2O) from six production facilities across the U.S. and Puerto Rico. Process-related emissions account for 1.6 million metric tons CO_2e, or 52 percent of the total, while on-site stationary combustion emissions account for the remaining 1.5 million metric tons CO_2e emissions. Soda ash consumption in the U.S. generated 2.5 million metric tons CO_2e in 2006.

Emissions from consumption of soda ash are not addressed in this proposed rule as they do not occur at the soda ash manufacturing source. Emissions from the use of soda ash would be reported by the glass manufacturing industry, which consumes the soda ash.

For additional background information on soda ash manufacturing, please refer to the Soda Ash Manufacturing TSD (EPA–HQ–OAR–2008–0508–029).

2. Selection of Reporting Threshold

In developing the threshold for soda ash manufacturing, we considered emissions-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 per year. Table CC–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE CC–1. THRESHOLD ANALYSIS FOR SODA ASH MANUFACTURING

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	3,121,438	5	3,121,438	100	5	100
10,000	3,121,438	5	3,121,438	100	5	100
25,000	3,121,438	5	3,121,438	100	5	100
100,000	3,121,438	5	3,121,438	100	5	100

Facility-level emissions estimates based on known plant capacities suggest that all known facilities exceed the highest (100,000 metric tons CO_2e) threshold examined. Two facilities were excluded from this analysis based on available information (one has not been operating since 2004 and the second recycles or utilizes CO_2 emissions as part of the process, resulting in limited fugitive emissions). Even if sources are not operating at full capacity, all or most of them would still be expected to exceed the 25,000 metric ton threshold. We propose that all facilities report. Requiring all facilities to report would simplify the proposed rule, and ensure that 100 percent of the emissions from this industry are reported.

For a full discussion of the threshold analysis, please refer to the Soda Ash Manufacturing TSD (EPA–HQ–OAR–2008–0508–029). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from soda ash manufacturing (e.g., the 2006 IPCC Guidelines, DOE 1605(b)). These methodologies coalesce around three different options:

Option 1: Default emission factors would be applied to the amount of trona consumed or soda ash produced. This method would also involve applying an adjustment factor to the default emission factor to account for fractional purity of the trona consumed or soda ash produced. A default adjustment factor of 0.9 could be applied if country specific or plant specific information is not available. This option is consistent with IPCC Tier 2 methods and 1605(b)'s ''A'' rated approach.

Option 2: Develop a site-specific emission factor (determined by an annual stack test). This method would account for the fractional purity of the trona consumed or soda ash produced. This approach is consistent with IPCC's Tier 2 method and consistent with the DOE 1605(b) ''A'' rated approach.

Option 3: Direct measurement of emissions using CEMS.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions, you would be required to follow requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

Under this proposed rule, if you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, we propose that facilities estimate process-related CO_2 emissions using a modified Option 1. Refer to proposed 40 CFR part 98, subpart C for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

The proposed monitoring method requires facilities to use default stoichiometric emission factors (either 0.097 for trona consumed (ratio of ton of CO_2 emitted for each ton of trona) or 0.138 for soda ash produced (ratio of ton of CO_2 emitted for each ton of natural soda ash produced)) and to measure the fractional purity of the trona or soda ash. These factors are then applied to the estimated quantity of raw material input or the amount of soda ash output. Raw material input and output quantities are assumed to be readily available to facilities. In order to assess the fractional purity of trona or soda ash (as determined by the level of the inorganic carbon present), we propose that facilities test samples of trona using in-house TOC analyzers or test samples of soda ash for inorganic carbon expressed as total alkalinity using applicable test methods. We are assuming that soda ash facilities are conducting daily tests of fractional purity and can develop monthly averages from daily tests. This methodology was chosen because it would be more accurate than methods using default factors for fractional purity.

We decided against applying a default emission factor and a default adjustment factor of 0.9 to either the total amount of trona consumed or soda ash produced. According to IPCC, the stoichiometric ratio used in the default emission factor equation is an exact number and assumes 100 percent purity of the input or output and the uncertainty of the default emission factor is negligible. However, simple application of default emission and adjustment factors would not take into account the actual fractional purities of either the trona input or soda ash output.

We also decided against proposing the second option to determine an annual site-specific emission factor. The stack from the calciner (kiln) emits CO_2 emissions from both combustion- and process-related sources. An annual stack test would not capture the variability in stationary combustion emissions associated with consumption of various types of fuels, so would not significantly reduce the uncertainty for developing annual estimates of CO_2 emissions. While not improving emissions estimates significantly, annual stack testing would be burdensome to industry. We have concluded that measuring fractional purity, as described in the proposed modified Option 1 approach, would improve emissions estimates, with a minimal cost burden.

The third option we considered, but did not select as the proposed option, was continuous direct measurement of emissions from soda ash manufacturing. This option is consistent with the 2006 IPCC Guidelines Tier 3 method. Use of a CO_2 CEMS would eliminate the need for further periodic review because this method would account for the variability in GHG emissions due to changes in the process or operation over time. While this method does tend to provide the most accurate CO_2 emissions measurements and can measure both the combustion- and process-related CO_2 emissions, it is likely the costliest of all the monitoring methods. Installation of CEMS would require significant additional burden to facilities given that few soda ash facilities currently have CO_2 CEMS.

The various options of monitoring GHG emissions, as well as the domestic and international GHG monitoring guidelines and protocols researched, are elaborated in the Soda Ash Manufacturing TSD (EPA–HQ–OAR–2008–0508–029).

4. Selection of Procedures for Estimating Missing Data

We propose that no missing data procedures would apply to estimating CO_2 process emissions because the calculations are based on production, or trona consumption, which are closely tracked production inputs and outputs. Given that the fractional purity would have to be tested on a daily basis, if a value is missing the test should be repeated. Therefore, 100 percent data availability would be required.

5. Selection of Data Reporting Requirements

We propose that reported data include annual CO_2 process emissions from each soda ash manufacturing line, and the number of soda ash manufacturing lines, as well as any stationary fuel combustion emissions. In addition, we propose that facilities report the following data for each soda ash manufacturing line: Annual soda ash production, annual soda ash production capacity, annual trona quantity consumed, fractional purity (i.e., inorganic carbon content) of the trona or soda ash, and number of operating hours in the calendar year. These additional data, most of which are used as a basis for calculating emissions, are needed to understand the emissions data, verify the reasonableness of the reported emissions, and identify outliers. A full list of data that would be reported is included in proposed 40 CFR part 98, subparts A and CC.

6. Selection of Records That Must Be Retained

We propose that facilities keep information on monthly production of soda ash (metric tons), monthly consumption of trona (metric tons), and daily fractional purity (i.e., inorganic carbon content) of the trona or soda ash. A full list of records that must be retained onsite is included in the proposed rule.

DD. Sulfur Hexafluoride (SF_6) From Electrical Equipment

1. Definition of the Source Category

The largest use of SF_6, both in the U.S. and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity. The gas has been employed by the electric power industry in the U.S. since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, other switchgear, and gas-insulated lines. SF_6 has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas. Currently, there are no available substitutes for SF_6 in this application. For further information, see the SF_6 from Electrical Equipment TSD (EPA–HQ–OAR–2008–0508–030).

Fugitive emissions of SF_6 can escape from gas-insulated substations and switch gear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal.

PFCs are sometimes used as dielectrics and heat transfer fluids in power transformers. PFCs are also used for retrofitting CFC–113 cooled transformers. One PFC used in this application is perfluorohexane (C_6F_{14}). In terms of both absolute and carbon-weighted emissions, PFC emissions from electrical equipment are generally believed to be much smaller than SF_6 emissions from electrical equipment; however, there may be some exceptions to this pattern, according to the 2006 IPCC Guidelines.

According to the 2008 U.S. Inventory, total U.S. estimated emissions of SF_6 from an estimated 1,364 electric power system utilities[86] were 12.4 million metric tons CO_2e in 2006. We do not have an estimate of PFC emissions.

This source category comprises electric power transmission and distribution systems that operate gas-insulated substations, circuit breakers, and other switchgear, or power transformers containing sulfur-hexafluoride (SF_6) or PFCs.

2. Selection of Reporting Threshold

We propose to require electric power systems to report their SF_6 and PFC emissions if the total nameplate capacity of their SF_6-containing equipment exceeds 17,820 lbs of SF_6. This threshold is equivalent to an emissions threshold of 25,000 metric tons CO_2e, and was developed using historical (1999) data from utilities that participate in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems (Partnership).

In addition, we considered emission-based threshold options of 1,000 metric tons CO_2e; 10,000 metric tons CO_2e; and 100,000 metric tons CO_2e. Nameplate capacity thresholds of 713; 7,128; and 71,280 lbs of SF_6 for all utilities were also considered, corresponding to the emission threshold options of 1,000; 10,000; and 100,000 metric tons CO_2e, respectively. Summaries of the threshold options (capacity-based and emissions-based) and the number of utilities and emissions falling above each threshold are presented in Tables DD–1 and DD–2 of this preamble.

TABLE DD–1. OPTIONS FOR CAPACITY-BASED THRESHOLDS FOR ELECTRIC POWER SYSTEMS

Nameplate capacity threshold for all utilities (lbs SF_6)	Total national emissions $MMTCO_2e$/yr	Total number of facilities	Emissions covered		Facilities covered	
			$MMTCO_2e$/yr	Percent	Number	Percent
713	12.4	1,364	12.19	98	578	42
7,128	12.4	1,364	10.96	88	183	13
17,820	12.4	1,364	10.32	83	141	10
71,280	12.4	1,364	5.95	48	35	3

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[86] The estimated total number of electric power system (EPS) utilities includes all companies participating in the SF_6 Emission Reduction Partnership for Electric Power Systems and the number includes non-partner utilities with non-zero transmission miles. The estimated total number of EPS utilities that emit SF_6 likely underestimates the population, as some utilities may own high-voltage equipment yet not own transmission miles. However, the estimated number is consistent with the U.S. inventory methodology, in which only non-partner utilities with non-zero transmission miles and partner utilities are assumed to emit SF_6.

TABLE DD–2. OPTIONS FOR EMISSIONS-BASED THRESHOLDS FOR ELECTRIC POWER SYSTEMS

Threshold level metric tons CO_2e/yr	Total national emissions $MMTCO_2e$/yr	Total number of facilities	Emissions covered		Facilities covered	
			$MMTCO_2e$/yr	Percent	Number	Percent
1,000	12.4	1,364	12.20	98	564	41
10,000	12.4	1,364	10.87	88	158	12
25,000	12.4	1,364	10.11	82	111	8
100,000	12.4	1,364	5.84	47	27	2

We selected a nameplate capacity threshold equivalent to the 25,000 metric tons CO_2e emissions threshold level. A capacity-based threshold was selected because it permits utilities to quickly determine whether they are covered. There have been many mergers and acquisitions in the electric power industry and nameplate capacity is generally a known variable as a result of these transactions.

The proposed threshold is consistent with the threshold for other source categories. Based on information from the Partnership and from the Universal Database Interface Directory of Electric Power Producers and Distributors, we estimate that the nameplate capacity threshold covers only a small percentage of total utilities (10 percent or 141 utilities), while covering the majority of annual emissions (approximately 83 percent).

Other Options Considered. We considered setting a threshold based on the length of the transmission lines, defined as the miles of lines carrying voltages above 34.5 kV, owned by electric power systems. The transmission-mile threshold equivalent to 25,000 metric tons CO_2e is 1,186 miles. The fractions of utilities and emissions covered by this threshold would be almost identical to those covered by the nameplate-capacity threshold.

We decided not to propose the transmission-mile threshold because the relationship between emissions and transmission miles, while strong, is not as strong as that between emissions and nameplate capacity. On the one hand, some utilities have far larger nameplate capacities and emissions than would be expected based on their transmission miles. This is the case for some urban utilities that have large volumes of SF_6 in gas-insulated switchgear. On the other hand, some utilities have lower nameplate capacities and emissions than would be expected based on their transmission miles, because most of their transmission lines use lower voltages than average and therefore typically use less SF_6 than average as well.

Additional information supporting the selection of the threshold can be found in the SF_6 from Electrical Equipment TSD (EPA–HQ–OAR–2008–0508–030). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

In developing the proposed approach, we reviewed the 2006 IPCC Guidelines, the SF_6 Emissions Reduction Partnership for Electric Power Systems, the U.S. GHG Inventory, DOE 1605(b), EPA's Climate Leaders Program, and TCR. In the IPCC Guidelines, Tiers 1 and 2 are based on default SF_6 and PFC emission factors, but Tier 3 is based on using utility-specific information to estimate emissions of both SF_6 and PFC using a mass-balance analysis.

The proposed monitoring methods for calculating SF_6 and PFC emissions from electric power systems are similar to the methodologies described in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems (Partnership) Inventory Reporting Protocol and Form and the 2006 IPCC Guidelines Tier 3 methods for emissions from electrical equipment. In general, these protocols and guidance all support using a mass-balance approach as the most accurate alternative to estimate emissions.

We propose that you report all SF_6 and PFC emissions, including those from equipment installation, equipment use, and equipment decommissioning and disposal. This requirement would apply only to systems where the total nameplate capacity of their SF_6-containing equipment exceeds 17,820 lbs of SF_6. The Tier 3 approach is being proposed because it is the most accurate and it is feasible for all systems to conduct the mass balance analysis for SF_6 and PFC using readily available information.

The mass-balance approach works by tracking and systematically accounting for all facility uses of SF_6 and PFC during the reporting year. The quantities of SF_6 and PFC that cannot be accounted for are assumed to have been emitted to the atmosphere. The emissions of SF_6 and PFC would be estimated and reported separately.

The following equation describes the proposed utility-level mass-balance approach:

User Emissions = Decrease in SF_6 Inventory + Acquisitions of SF_6 − Disbursements of SF_6 − Net Increase in Total Nameplate Capacity of Equipment

Where:

Decrease in SF_6 Inventory is SF_6 stored in containers (but not in equipment) at the beginning of the year minus SF_6 stored in containers (but not in equipment) at the end of the year.

Acquisitions of SF_6 is SF_6 purchased from chemical producers or distributors in bulk + SF_6 purchased from equipment manufacturers or distributors with or inside of equipment + SF_6 returned to site after off-site recycling.

Disbursements of SF_6 is SF_6 in bulk and contained in equipment that is sold to other entities + SF_6 returned to suppliers + SF_6 sent off-site for recycling + SF_6 sent to destruction facilities.

Net Increase in Total Nameplate Capacity of Equipment is the Nameplate capacity of new equipment minus Nameplate capacity of retiring equipment. (Note that Nameplate capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.)

The same method is being proposed to estimate emissions of PFCs from power transformers.

Other Options Considered. We also considered the IPCC Tier 1 and the IPCC Tier 2 methods for calculating and reporting SF_6 and PFC emissions, but did not choose them for several reasons. Although the IPCC Tier 1 method is simpler, the default emission factors have large uncertainty due to variability associated with handling and management practices, age of equipment, mix of equipment, and other similar factors. Utilities participating in EPA's Partnership have reduced their emission factors to less than Tier 1 default values. Less than 10 percent of U.S. utilities participate in this program; however, these utilities represent close to 40 percent of the U.S. grid, so the IPCC Tier 1 emission factors are not accurate for a large percentage of the U.S. source category.

IPCC Tier 2 methods use country-specific emission factors, but the Partner utilities have demonstrated by calculating their own utility-level emission rates that large variability exists in utility-level emission rates across the nation (i.e., emission rates range from less than one percent of a utility's SF_6 inventory to greater than 35 percent). As a result, we are not proposing the IPCC Tier 2 method.

4. Selection of Procedures for Estimating Missing Data

It is expected that utilities should have 100 percent of the data needed to perform the mass balance calculations for both SF_6 and PFCs. Partner utilities missing inputs to the mass-balance approach have estimated emissions using other methods, such as assuming that all purchased SF_6 is emitted. However, this method over-estimates emissions, and we do not recommend this method of estimation in the absence of more complete data. The use of the mass-balance approach requires correct records for all inputs.

5. Selection of Data Reporting Requirements

We propose annual reporting for facilities in the electric power systems industry. Each facility would report all SF_6 and PFC emissions, including those from equipment installation, equipment use, and equipment decommissioning and disposal. However, the emissions would not need to be broken down and reported separately for installation, use or disposal. Along with their emissions, utilities would be required to submit the following supplemental data, nameplate capacity (existing as of the beginning of the year, new during the year, and retired during the year), transmission miles, SF_6 and PFC sales and purchases, SF_6 and PFC sent off-site for destruction or to be recycled, SF_6 and PFC returned from offsite after recycling, SF_6 and PFC stored in containers at the beginning and end of the year, SF_6 and PFC with or inside new equipment purchased in the year, SF_6 and PFC with or inside equipment sold to other entities and SF_6 and PFC returned to suppliers.

These data would be submitted because they are the minimum data that are needed to understand and reproduce the emission calculations that are the basis of the reported emissions. Transmission miles would be included in the reported data so that the reasonableness of the reported emissions could be quickly checked using default emission factors.

6. Selection of Records That Must Be Retained

We propose that electric power systems be required to keep records documenting (1) their adherence to the QA/QC requirements specified in the proposed rule, and (2) the data that would be included in their emission reports, as specified above. The QA/QC requirements records include check-out sheets and weigh-in procedures for cylinders, residual gas amounts in cylinders sent back to suppliers, invoices for gas and equipment purchases or sales, and records of equipment nameplate capacity. The records that are being proposed are the minimum needed to reproduce and confirm emission calculations.

EE. Titanium Dioxide Production

1. Definition of the Source Category

Titanium dioxide is a metal oxide commonly used as a white pigment in paint manufacturing, paper, plastics, rubber, ceramics, fabrics, floor covering, printing ink, and other applications. The majority of TiO_2 production is for the manufacturing of white paint. National production of TiO_2 in 2006 was approximately 1,400,000 metric tons.

Titanium dioxide is produced through two processes: The chloride process and the sulfate process. According to USGS, most facilities in the U.S. employ the chloride process. Total U.S. production of titanium dioxide pigment through the chloride process was approximately 1.4 metric tons in 2006, a 7 percent increase compared to 2005. The chloride process emits process-related CO_2 through the use of petroleum coke and chlorine as raw materials, while the sulfate process does not emit any significant process-related GHGs.

The chloride process is based on two chemical reactions. Petroleum coke (C) is oxidized as the reducing agent in the first reaction in the presence of chlorine and crystallized iron titanium oxide ($FeTiO_3$) to form and emit CO_2. A special grade of petroleum coke, known as calcined petroleum coke, is a highly electrically conductive carbon (fixed carbon content >98 percent) and is used in several manufacturing processes including titanium dioxide (in the chloride process), aluminum, graphite, steel, and other carbon consuming industries. For the purposes of this rulemaking effort EPA is assuming the carbon content factor for calcined petroleum coke is 100 percent or a multiplier of 1. Therefore, no site-specific factor needs to be determined. The titanium tetrachloride ($TiCl_4$) produced through this first reaction is oxidized with oxygen at about 1,000 °C, and calcinated in a second reaction to remove residual chlorine and any hydrochloric acid that may have formed in the reaction producing titanium dioxide (TiO_2).

National emissions from titanium dioxide production were estimated to be 3.6 million metric tons CO_2e in 2006. These emissions include process-related (CO_2) and on-site stationary combustion emissions (CO_2, CH_4, and N_2O) from eight production facilities. Process-related emissions from titanium dioxide production were 1.87 million metric tons CO_2e or 47 percent of the total, while on-site combustion emissions account for the remaining 1.8 million metric tons CO_2e emissions in 2006.

For additional background information on titanium dioxide production, please refer to the Titanium Dioxide Production TSD (EPA–HQ–OAR–2008–0508–031).

2. Selection of Reporting Threshold

In developing the threshold for titanium dioxide production, we considered an emissions-based threshold 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. Table EE–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE EE–1. THRESHOLD ANALYSIS FOR TITANIUM DIOXIDE PRODUCTION

Threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	3,685,777	8	3,685,777	100	8	100
10,000	3,685,777	8	3,685,777	100	8	100
25,000	3,685,777	8	3,685,777	100	8	100

TABLE EE–1. THRESHOLD ANALYSIS FOR TITANIUM DIOXIDE PRODUCTION—Continued

Threshold level metric tons CO_2e/yr	Total national emissions	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
100,000	3,685,777	8	3,628,054	98	7	88

At the threshold levels of 1,000 metric tons CO_2e, 10,000 metric tons CO_2e, and 25,000 metric tons CO_2e, all facilities exceed the threshold, therefore covering 100 percent of total emissions. At the 100,000 metric tons CO_2e level, one facility would not exceed the threshold and 98 percent of emissions would be covered. In order to simplify the rule, and avoid the need for the source to calculate and report whether the facility exceeds threshold value, we are proposing that all titanium dioxide production facilities report. Including all facilities simplifies the rule and ensures 100 percent coverage without significantly increasing the number of affected facilities expected to report relative to the 25,000 metric ton threshold.

For a full discussion of the threshold analysis, please refer to the Titanium Dioxide Production TSD (EPA–HQ–OAR–2008–0508–031). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating process-related emissions from titanium dioxide production (e.g., the 2006 IPCC Guidelines, U.S. GHG Inventory, Australian Government's National Greenhouse and Energy Reporting System). These methods coalesce around two different options.

Option 1. CO_2 emissions are estimated by applying a default emission factor to annual facility level titanium dioxide production.

Option 2. CO_2 emissions are estimated based on the facility-specific quantity of reducing agents or calcined petroleum coke consumed.

Option 3. Direct measurement of emissions using CEMS.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions you would be required to follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions. Also, refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

Under this proposed rule, if you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C, we propose that facilities use the second option discussed above to estimate process-related CO_2 emissions. Refer to proposed 40 CFR part 98, subpart C specifically for procedures to estimate combustion-related CO_2, CH_4 and N_2O emissions.

Under this approach the total amount of calcined petroleum coke consumed would be assumed to be directly converted into CO_2 emissions. The amount of calcined petroleum coke can be obtained from facility records, as that data would be readily available. The carbon oxidation factor for the calcined petroleum coke is assumed to be 100 percent, because any amount that is not oxidized is an insignificant amount. For the purposes of this rulemaking effort EPA is assuming the carbon oxidation factor for calcined petroleum coke, is equal to 100/100 or 1. Therefore, no site-specific factor needs to be determined.

We decided not to propose the option to use continuous direct measurement because it would not lead to significantly reduced uncertainty in the emissions estimate over the proposed option. Furthermore, the cost impact of requiring the installation of CEMS is high in comparison to the relatively low amount of emissions that would be quantified from the titanium production sector.

We decided not to propose the option to apply default emission factors to titanium dioxide production to quantify process-related emissions. Although default emissions factors have been developed for quantifying process-related emissions from titanium dioxide production, the use of these default values is more appropriate for sector wide or national total estimates than for determining emissions from a specific plant. Estimates based on site-specific consumption of reducing agents are more appropriate for reflecting differences in process design and operation. According to the 2006 IPCC Guidelines, the uncertainty associated with the proposed approach is much lower given that facilities closely track consumption of the calcined petroleum coke (accurate within 2 percent), whereas the uncertainty associated with the default emission factor is approximately 15 percent.

The various approaches to monitoring GHG emissions are elaborated in the Titanium Dioxide Production TSD (EPA–HQ–OAR–2008–0508–031).

4. Selection of Procedures for Estimating Missing Data

It is assumed that a facility would be able to supply data on annual calcined petroleum coke consumption data. Therefore, 100 percent data availability is required for all parameters.

5. Selection of Data Reporting Requirements

We propose that facilities submit process-related CO_2 emissions on an annual basis, as well as any stationary fuel combustion emissions. In addition we propose that facilities report the following additional data used as the basis of the calculations to assist in verification of estimates, checks for reasonableness, and other data quality considerations. The data includes: annual production of titanium dioxide, annual amount of calcined petroleum coke consumed, and number of operating hours in the calendar year. Facilities are not required to submit carbon oxidation factor for calcined petroleum coke; this value is assumed to be 100 percent, as any amount that is not oxidized is assumed to be an insignificant amount. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and EE.

6. Selection of Records That Must Be Retained

In addition to the data reported, we propose that facilities maintain records of monthly production of titanium dioxide and monthly amounts of calcined petroleum coke consumed. These records hold values that are directly used to calculate the emissions that are reported and are necessary to allow determination of whether GHG emissions monitoring and calculations were done correctly. They also are needed to understand the emissions data and verify the reasonableness of the reported emissions and identify potential outliers.

A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and EE.

FF. Underground Coal Mines

1. Definition of the Source Category

Coal mining can produce significant amounts of CH_4 from the following areas and activities: Active underground coal mines, surface coal mines, post-coal mining activities and abandoned underground coal mines.

An active underground coal mine is a mine at which coal is produced by tunneling into the earth to a subsurface coal seam, which is then mined with equipment such as cutting machines, extracted and transported to the surface. In underground mines, CH_4 is released from the coal and surrounding rock strata due to mining activities, and can create an explosive hazard. Ventilation systems dilute in-mine concentrations to within safe limits, and exhaust CH_4 to the atmosphere.

Mines that produce large amounts of CH_4 also rely on degasification (or ''drainage'') systems to remove CH_4 from the coal seam in advance of, during, or after mining, producing high-concentration CH_4 gas.

CH_4 from degasification and ventilation systems can be liberated to the atmosphere or destroyed. Destroyed CH_4 includes, but is not limited to, CH_4 combusted by flaring, CH_4 destroyed by thermal oxidation, CH_4 combusted for use in onsite energy or heat production technologies, CH_4 that is conveyed through pipelines (including natural gas pipelines) for offsite combustion, and CH_4 that is collected for any other onsite or offsite use as a fuel.

At surface mines, CH_4 in the coal seams is directly exposed to the atmosphere.

Post coal mining activities release emissions as coal continues to emit CH_4 as it is stored in piles, processed, and transported.

At abandoned (closed) underground coal mines, CH_4 from the coal seam and mined-out area may vent to the atmosphere through fissures in rock strata or through incompletely sealed boreholes. It is possible to recover and use the CH_4 stored in abandoned coal mines.

Total U.S. CH_4 emissions from active mining operations in 2006 were estimated to be 58.5 million metric tons CO_2e from these sources. Of this, active underground mines accounted for 61 percent of emissions, or 35.9 million metric tons CO_2e, surface mines accounted for 24 percent of emissions, or 14.0 million metric tons CO_2e, and post-mining emissions accounted for 15 percent, or 8.6 million metric tons CO_2e. CH_4 emissions from abandoned (closed) underground coal mines were estimated to contribute another 5.4 million metric tons CO_2e. On-site stationary fuel combustion emissions at coal mining operations accounted for an estimated 9.0 million metric tons CO_2e emissions in 2006. Proposed requirements for stationary fuel combustion emissions are set forth in proposed 40 CFR part 98, subpart C.

We propose to require reporting of emissions from ventilation and degasification systems at active underground mines in this rule. This includes the fugitive CH_4 from these systems and also CO_2 emissions from destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use. Due to difficulties associated with obtaining accurate measurements from surface mines, post-mining activities, and abandoned (closed) mines, and in some cases, difficulties in identifying owners of these sources, we propose to exclude fugitive CH_4 emissions from these sources from this rule. These sources could still surpass the threshold for stationary fuel combustion activities and therefore be required to report stationary fuel combustion-related emissions.

Although fugitive CO_2 may be emitted from coal seams, it is not typically a significant source of emissions from U.S. coal seams compared to CH_4. Furthermore, methodologies are not widely available to measure these emissions, and therefore they are not proposed for inclusion in this rule.

For additional background information on coal mining, please refer to the Underground Coal Mines TSD (EPA–HQ–OAR–2008–0508–032).

2. Selection of Reporting Threshold

In developing the threshold for active underground coal mines, we considered emissions-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 for total onsite emissions from stationary fuel combustion, ventilation, and degasification. We also considered requiring all coal mines for which CH_4 emissions from the ventilation system are sampled quarterly by the MSHA to report under this proposal. Table FF–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE FF–1. THRESHOLD ANALYSIS FOR COAL MINING AT ACTIVE UNDERGROUND COAL MINES

Threshold level metric tons CO_2e/yr	Total national emissions (metric tons CO_2e)	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
MSHA reporting	39,520,000	612	33,945,956	86	128	21
1,000	39,520,000	612	33,945,446	86	125	20
10,000	39,520,000	612	33,926,526	86	122	20
25,000	39,520,000	612	33,536,385	85	100	16
100,000	39,520,000	612	31,054,856	79	53	9

We propose that all active underground coal mines for which CH_4 from the ventilation system is sampled quarterly by MSHA (or on a more frequent basis), are required to report under this rule. MSHA conducts quarterly testing of CH_4 concentration and flow at mines emitting more than 100,000 cf CH_4 per day. We selected this threshold because subjecting underground mine operators to a new emissions-based threshold is unnecessarily burdensome, as many of these mines are already subject to MSHA regulations. The MSHA threshold for reporting of 100,000 cf CH_4 per day covers approximately 94 percent of the CH_4 emitted from underground coal mine ventilation systems and about 86 percent of total emissions from underground mining (including stationary fuel combustion emissions at mine sites, as shown in Table FF–1 of this preamble).

For additional background information on the thresholds for coal mining, please refer to the Underground Coal Mines TSD (EPA–HQ–OAR–2008–0508–032). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating CH_4 emissions from coal mining (e.g., the 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), and Australia's National Greenhouse Gas and Energy Reporting System). These methodologies coalesce into three different approaches.

Option 1. Engineering approaches, whereby default emission factors would be applied to total annual coal production (for ventilation systems), or emission factors associated with the system type (for degasification systems) to estimate fugitive emissions.

Option 2. Periodic sampling of CH_4. Quarterly or more frequent samples could be taken in order to develop a site-specific emission factor.

Option 3. Use of CEMS.

Proposed Option for Liberated Ventilation CH_4. We propose Option 2, quarterly sampling of ventilation air for monitoring ventilation CH_4 liberated from coal mines.

Under this option, coal mine operators are required to either (a) independently collect quarterly samples of CH_4 released from the ventilation system(s), using MSHA procedures, have these samples analyzed for CH_4 composition, and report the results to us, or (b) to obtain the results from the quarterly testing that MSHA already conducts, and report those to EPA.

MSHA inspectors currently perform quarterly mine safety inspections on mines emitting 100,000 cf CH_4 or more per day, and as part of these inspections, the inspectors test CH_4 emissions rates and ventilation shaft flow, using MSHA-approved sampling procedures and devices. The sample bottles are sent to the MSHA lab for analysis and the results are provided back to the MSHA district offices for inclusion in the inspection report. Currently, the results of these quarterly measurements are generally not provided back to the mine.

We would like to take comment on whether relying on MSHA sampling procedures,[87] which were developed to ensure adherence to safety standards, is appropriate and sufficiently accurate for a GHG emissions reporting program. Further, we are interested in viewpoints on whether quarterly sampling is sufficient to account for potential fluctuations in emissions over smaller time increments (e.g., daily) from the mine. For more information on the MSHA sampling procedures, please refer to the Underground Coal Mines TSD (EPA–HQ–OAR–2008–0508–032).

For all ventilation systems with CH_4 destruction, CH_4 destruction would be monitored through direct measurement of CH_4 flow to combustion devices with continuous flow monitoring systems. The resulting CO_2 emissions would be calculated from these monitored values. If CH_4 from ventilation systems is destroyed, such a system would have sufficient continuous monitoring devices associated with it that such required monitoring would not propose any additional burden.

We considered requiring mines to monitor ventilation CH_4 concentrations by daily sampling, in place of quarterly sampling, for this rule. Many mines sample CH_4 daily from ventilation systems using handheld CH_4 analyzers. The primary advantages of this option are that many mines already take these measurements and this would therefore not impose an additional monitoring burden, and that daily measurements of CH_4 concentration and ventilation shaft flowrates could allow for more accurate annual estimates than quarterly measurements. The primary disadvantages of this option relative to the other options that were considered are that it is not as accurate as continuous emissions measurements, and that, if required, it would impose a cost burden for those mines that do not already have a daily sampling and monitoring program in place.

We also decided against requiring mines with CEMS installed at ventilation systems to use the continuous monitoring devices to monitor ventilation system CH_4 emissions. Mines without CEMS would follow the quarterly option proposed above. In many underground mines, CEMS devices are already in operation. In such cases, this option may involve only placing such devices at or near the mine vent outflows where the air samples are taken by MSHA inspectors. The primary advantage of continuous monitoring is that it could increase the accuracy of annual CH_4 emissions calculations because it takes into consideration any variability in emissions from mining operations that may not be represented in the quarterly sampling. Moreover, since such devices are already used within the mine to assess safety conditions, mine operator personnel are familiar with their operation. The disadvantage in requiring CEMS installation would be the larger costs associated with purchasing and maintaining these devices. We seek comment on the accuracy and cost of monitoring ventilation emissions with CEMS.

Finally, we decided not to propose Option 1, which applies default emission factors to coal production. We decided against the use of the default CH_4 emission factors because their application is more appropriate for GHG estimates from aggregated process information on a sector-wide or national basis than for determining GHG emissions from specific mines.

Proposed Option for Degasification. We propose that all coal mine operators subject to this rule that deploy degasification systems in underground mines install continuous monitors for CH_4 content and flowrates on all degasification wells or degasification vent holes, and that all CH_4 liberated and CH_4 destroyed from these systems be reported (Option 3). For all systems with CH_4 destruction, CH_4 destruction would be monitored through direct measurement of CH_4 flow to combustion devices with continuous monitoring systems. The resulting CO_2 emissions would be calculated from these monitored values. Option 3 is consistent with current practices for CH_4 that is destroyed, where the produced gas volume is presumably already being measured with continuous monitors. For gas that is simply vented to the atmosphere from degasification wells, this requirement would ensure that this gas is accurately measured.

We considered, but are not proposing, Option 1, which would estimate CH_4 emissions based on the type of degasification system employed. For example, in developing the U.S. GHG Inventory, we currently assume for selected mines that degasification emissions account for 40 percent of total CH_4 liberated from the mine. This method is very simplistic and least costly, but there is relatively larger uncertainty associated with the emissions estimated. Considering that emissions from many degasification wells are currently monitored, and the need to characterize the quantity of these vented emissions more accurately, we do not believe this option is appropriate.

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[87] NIOSH, *Handbook for Methane Control in Mining,* CDC Information Circular 9486, June 2006.

We also considered, but are not proposing, Option 2, which would require mine operators to conduct periodic sampling of gob gas vent holes and any other degasification boreholes, rather than installing continuous monitoring. While such an approach would involve lower capital costs than CEMS, greater labor costs would be involved with traveling to each (often remote) well site to take samples. Moreover, this method would not accurately reflect fluctuations in gas quantity and CH_4 concentration. Pre-mining degasification and gob wells are generally characterized by large variations in emissions over time, as emissions can decline rapidly in each individual well, while new wells/vents come on line as mining advances.

The various approaches to monitoring GHG emissions are elaborated in the Underground Coal Mines TSD (EPA–HQ–OAR–2008–0508–032).

4. Selection of Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation) a substitute data value for the missing parameter shall be used in the calculations.

For each missing value of CH_4 concentration, flow rate, temperature, and pressure for ventilation and degassification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

5. Selection of Data Reporting Requirements

We propose that coal mines report, for all ventilation shafts and degasification systems (e.g., all boreholes), the following parameters: CH_4 liberated from the shaft or borehole, the quantity of CH_4 destroyed (if applicable), and net CH_4 emissions on an annual basis. In addition to reporting emissions, all input data needed to calculate liberation and emissions are to be reported, as well as mine days of operation (for the ventilation and degasification systems). A full list of data to be reported is includedproposed 40 CFR part 98, subparts A and FF.

6. Selection of Records That Must Be Retained

Reporters are to retain all data listed in Section V.FF.5 of this preamble. A full list of records to be retained onsite is included in proposed 40 CFR part 98, subparts A and FF.

GG. Zinc Production

1. Definition of the Source Category

Zinc is a metal used as corrosion-protection coatings on steel (galvanized metal), as die castings, as an alloying metal with copper to make brass, and as chemical compounds in rubber, ceramics, paints, and agriculture. For this proposed rule, we are defining the zinc production source category to consist of zinc smelters using pyrometallurgical processes and secondary zinc recycling facilities. Zinc smelters can process zinc sulfide ore concentrates (primary zinc smelters) or zinc-bearing recycled and scrap materials (secondary zinc smelters). A secondary zinc recycling facility recovers zinc from zinc-bearing recycled and scrap materials to produce crude zinc oxide for use as a feed material to zinc smelters. Many of these secondary zinc recycling facilities have been built specifically to process dust collected from electric arc furnace operations at steel mini-mills across the country.

There are no primary zinc smelters in the U.S. that use pyrometallurgical processes. The one operating U.S. pyrometallurgical zinc smelter processes crude zinc oxide and calcine produced from recycled zinc materials. These feed materials are first processed through a sintering machine. The sinter is mixed with metallurgical coke and fed directly into the top of an electrothermic furnace. Metallic zinc vapor is drawn from the furnaces into a vacuum condenser, which is then tapped to produce molten zinc metal. The molten metal is then transferred directly to a zinc refinery or cast into zinc slabs.

Secondary zinc recycling facilities operating in the U.S. use either of two thermal processes to recover zinc from recycled electric arc furnace dust and other scrap materials. For the Waelz kiln process, the feed material is charged to an inclined rotary kiln together with petroleum coke, metallurgical coke, or anthracite coal. The zinc oxides in the gases from the kiln are then collected in a baghouse or electrostatic precipitator. The second recovery process used for electric arc furnace dust uses a water-cooled, flash-smelting furnace to form vaporized zinc that is subsequently captured in a vacuum condenser. The crude zinc oxide produced at secondary zinc recycling facilities is shipped to a zinc smelter for further processing.

Zinc production results in both combustion and process-related GHG emissions. The major sources of GHG emissions from a zinc production facility are the process-related emissions from the operation of electrothermic furnaces at zinc smelters and Waelz kilns at secondary zinc recycling facilities. In an electrothermic furnace, reduction of zinc oxide using carbon provided by the charging of coke to the furnace produces CO_2. In the Waelz kiln, the zinc feed materials are heated to approximately 1200 °C in the presence of carbon producing zinc vapor and carbon monoxide (CO). When combined with the surplus of air in the kiln, the zinc vapors are oxidized to form crude zinc oxide, and the CO oxidized to form process-related CO_2 emissions.

Total nationwide GHG emissions from zinc production facilities operating in the U.S. were estimated to be approximately 851,708 metric tons CO_2e for the year 2006. This total GHG emissions estimate includes both process-related emissions (CO_2 and CH_4) and the additional combustion emissions (CO_2, CH_4, and N_2O). Process-related GHG emissions were approximately 528,777 metric tons CO_2e emissions (62 percent of the total emissions). The remaining 38 percent or 322,931 metric tons CO_2e are from onsite stationary combustion.

Additional background information about GHG emissions from the zinc production source category is available in the Zinc Production TSD (EPA–HQ–OAR–2008–0508–033).

2. Selection of Reporting Threshold

Zinc smelters and secondary zinc recycling facilities in the U.S. vary in types and sizes of the metallurgical processes used and mix of zinc-containing feedstocks processed to produce zinc products. In developing the threshold for zinc production facilities, we considered using annual GHG emissions-based threshold levels of 1,000, 10,000, 25,000 and 100,000 metric tons CO_2e. Table GG–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds.

TABLE GG–1. THRESHOLD ANALYSIS FOR ZINC PRODUCTION FACILITIES

Threshold level metric tons CO_2e/yr	Total nationwide emissions metric tons CO_2e/yr	National number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Facilities	Percent
1,000	851,708	9	851,708	100	9	100
10,000	851,708	9	843,154	99	8	89
25,000	851,708	9	801,893	94	5	56
100,000	851,708	9	712,181	84	4	44

We have concluded, based on emissions estimates using production capacity, that the one primary zinc facility exceeds all thresholds considered (Table GG–1 of this preamble). For the eight secondary zinc production facilities, just half are over a 25,000 metric tons CO_2e threshold. We decided it is appropriate to propose a threshold of 25,000 metric tons CO_2e for reporting emissions from zinc production facilities that is consistent with the threshold level being proposed for other source categories. This threshold level would avoid placing a reporting burden on a zinc production facility with inherently low GHG emissions because of the type of metallurgical processes used and type of zinc product produced while still requiring the reporting of GHG emissions from the zinc production facilities releasing most of the GHG emissions in the source category. More discussion of the threshold selection analysis is available in the Zinc Production TSD (EPA–HQ–OAR–2008–0508–033). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

EPA reviewed existing domestic and international GHG monitoring guidelines and protocols including the 2006 IPCC Guidelines, U.S. GHG Inventory, the EU Emissions Trading System, the Canadian Mandatory GHG Reporting Program, and the Australian National GHG Reporting Program. These methods coalesce around the following four options for estimating process-related GHG emissions from zinc production facilities. Zinc smelters using hydrometallurgical processes (e.g., electrolysis) would not be subject to the estimating and reporting requirements in proposed 40 CFR part 98, subpart GG for zinc production because the processes used at these smelters do not release process-related GHG emissions. However, combustion GHG emissions from the process equipment at these smelters burning natural gas or other carbon-based fuels could be subject to the estimating and reporting requirements for general stationary fuel combustion units in proposed 40 CFR part 98, subpart C, depending on the level of total GHG emissions from the facility with respect to the reporting thresholds specified in proposed 40 CFR part 98, subpart A.

Option 1. Apply a default emission factor for the process-related emissions to the facility zinc production rate. This is a simplified emission calculation method using only default emission factors to estimate CO_2 emissions. The method requires multiplying the amount of zinc produced by the appropriate default emission factors from the 2006 IPCC Guidelines.

Option 2. Perform a carbon balance of all inputs and outputs using monthly measurements of the carbon content of specific process inputs and measure the mass rate of these inputs. This method is the same as the IPCC Tier 3 approach and the higher order methods in the Canadian and Australian reporting programs. Implementation of this method requires owners and operators of affected zinc smelters to determine the carbon contents of materials added to the electrothermic furnace or Waelz kiln by analysis of representative samples collected of the material or from information provided by the material suppliers. In addition, the quantities of these materials consumed during production are measured and recorded. To obtain the process-related CO_2 emission estimate, the material carbon content would be multiplied by the corresponding mass of material consumed and a factor for conversion of carbon to CO_2. This method assumes that all of the carbon is converted during the reduction process. The facility owner or operator would determine the average carbon content of the material for each calendar month using information provided by the material supplier or by collecting a composite sample of material and sending it to an independent laboratory for chemical analysis.

Option 3. Use CO_2 emissions data from a stack test performed using U.S. EPA reference test methods to develop a site-specific process emissions factor which is then applied to quantity measurement data of feed material or product for the specified reporting period. This monitoring method is applicable to furnace or Waelz kiln configurations for which the GHG emissions are contained within a stack or vent. Using site-specific emissions factors based on short-term stack testing is appropriate for those facilities where process inputs (e.g., feed materials, carbonaceous reducing agents) and process operating parameters remain relatively consistent over time.

Option 4. Use direct emissions measurement of CO_2 emissions. For furnace and kiln configurations in which the process off-gases are contained within a stack or vent, direct measurement of the CO_2 emissions can be made by either continuously measuring the off-gas stream CO_2 concentration and flow rate using a CEMS, or periodically measuring the off-gas stream CO_2 concentration and flow rate using standard stack testing methods. Using a CEMS, the recorded emissions measurement data would be reported annually. An annual emissions test could be used to develop a site-specific process emissions factor which would then be applied to quantity measurement data of feed material or product for the specified reporting period.

Proposed Option. Under this proposed rule, if you are required to use an existing CEMS to meet the requirements outlined in proposed 40 CFR part 98, subpart C, you would be required to use CEMS to estimate CO_2 emissions. Provided that the CEMS capture all combustion- and process-related CO_2 emissions, you would be required to follow the requirements of proposed 40 CFR part 98, subpart C to estimate CO_2 emissions from the industrial source. You would also refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions.

If you do not have CEMS that meet the conditions outlined in proposed 40 CFR part 98, subpart C, or where the CEMS would not adequately account for process emissions, we propose that you follow Option 2, a carbon balance. You would still need to refer to proposed 40 CFR part 98, subpart C to estimate combustion-related CH_4 and N_2O emissions. Given the operating variations between the individual U.S. zinc production facilities (including differences in equipment configurations, mix of zinc feedstocks charged, and types of carbon materials used) we are proposing Option 2 to estimate CO_2 emissions from an electrothermic furnace or Waelz kiln at zinc production facilities because of the lower uncertainties indicated by the IPCC Guidelines for these types of emissions estimates, as compared to applying exclusively a default emissions factor based approach to these units on a nationwide basis.

We decided not to propose the use of default CO_2 emission factors (Option 1) because their application is more appropriate for GHG estimates from aggregated process information on a sector-wide or nationwide basis than for determining GHG emissions from specific facilities. According to the 2006 IPCC Guidelines, the uncertainty associated with default emission factors could be as high as 50 percent, while the uncertainty associated with facility specific estimates of process inputs and carbon contents would be within 5 to 10 percent. We considered the additional burden of the material measurements required for the carbon calculations small in relation to the increased accuracy expected from using this site-specific information to calculate the process-related CO_2 emissions.

We also decided against proposing Option 3 because of the potential for significant variations at zinc production facilities in the characteristics and quantities of the furnace or Waelz kiln inputs (e.g., zinc scrap materials, carbonaceous reducing agents) and process operating parameters. A method using periodic, short-term stack testing would not be practical or appropriate for those zinc production facilities where the furnace or Waelz kiln inputs and operating parameters do not remain relatively consistent over the reporting period.

Further details about the selection of the monitoring methods for GHG emissions are available in the Zinc Production TSD (EPA–HQ–OAR–2008–0508–033).

4. Selection of Procedures for Estimating Missing Data

For electrothermic furnaces or Waelz kilns for which the owner or operator calculates process GHG emissions using site-specific carbonaceous input material data, the proposed rule requires the use of substitute data whenever a quality-assured value of a parameter that is used to calculate GHG emissions is unavailable, or ''missing.'' If the carbon content analysis of carbon inputs is missing or lost the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. In those cases when an owner or operator uses direct measurement by a CO_2 CEMS, the missing data procedures would be the same as the Tier 4 requirements described for general stationary fuel combustion sources in proposed 40 CFR part 98, subpart C.

5. Selection of Data Reporting Requirements

The proposed rule would require annual reporting of the total annual CO_2 process-related emissions from the electrothermic furnaces and Waelz kilns at zinc production facilities, as well as any stationary fuel combustion emissions. In addition we propose that additional information which forms the basis of the emissions estimates also be reported so that we can understand and verify the reported emissions. This additional information includes the total number of Waelz kilns and electrothermic furnaces operated at the facility, the facility zinc product production capacity, and the number of facility operating hours in calendar year, carbon inputs by type, and carbon contents of inputs by type.

A complete list of data to be reported is included in proposed 40 CFR part 98, subparts A and GG.

6. Selection of Records That Must Be Retained

Maintaining records of the information used to determine the reported GHG emissions is necessary to enable us to verify that the GHG emissions monitoring and calculations were done correctly. We propose that all affected facilities maintain records of monthly facility production quantities for each zinc product, number of facility operating hours each month, and the annual facility production quantity for each zinc product (in tons). If you use the carbon input procedure, you would record for each carbon-containing input material consumed or used (other than fuel) the monthly material quantity, monthly average carbon content determined for material, and records of the supplier provided information or analyses used for the determination. If you use the CEMS procedure, you would maintain the CEMS measurement records.

A complete list of records to be retained is included in proposed 40 CFR part 98, subparts A and GG.

HH. Landfills

1. Definition of the Source Category

After being placed in a landfill, waste is initially decomposed by aerobic bacteria, and then by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria, which convert the fermentation products into stabilized organic materials and biogas.

CH_4 generation from a given landfill is a function of several factors, including the total amount of waste disposed in the landfill, the characteristics of the waste, and the climatic conditions. The amount of CH_4 emitted is the amount of CH_4 generated minus the amount of CH_4 that is destroyed and minus the amount of CH_4 oxidized by aerobic microorganisms in the landfill cover material prior to being released into the atmosphere.

Waste decaying in landfills also produces CO_2; however, this CO_2 is not counted in GHG totals as it is not considered an anthropogenic emission. Likewise, CO_2 resulting from the combustion of landfill CH_4 is not accounted as an anthropogenic emission under international accounting guidance.

According to the 2008 U.S. Inventory, MSW landfills emitted 111.2 million metric tons CO_2e of CH_4 in 2006. Generation of CH_4 at these landfills was 246.8 million metric tons CO_2e; however, 65.3 million metric tons CO_2e were recovered and used (destroyed) in energy projects, 59.8 million metric tons CO_2e were destroyed by flaring, and 12.4 million metric tons CO_2e were oxidized in cover soils. The majority of the CH_4 emissions from on-site industrial landfills occur at pulp and paper facilities and food processing facilities. In 2006, these landfills emitted 14.6 million metric tons CO_2e CH_4: 7.3 million metric tons CO_2e from pulp and paper facilities, and 7.2 million metric tons CO_2e from food processing facilities.

We propose to require reporting from open and closed,[88] MSW landfills meeting or exceeding the thresholds described below. We also propose to require reporting of industrial landfills (e.g., landfills at food processing, pulp and paper, and ethanol production facilities) meeting or exceeding the applicable thresholds in the relevant subparts. Hazardous waste landfills and construction and demolition landfills are not included in the landfills source category as they are not considered significant sources of GHG emissions.

The definition of landfills in this rule does not include land application units. Several refineries have land application units (also known as land treatment units) in which oily waste is tilled into the soil. We are seeking comment on the exclusion of land application units from this rule.

For additional background information on landfills, please refer to the Landfills TSD (EPA–HQ–OAR–2008–0508–034).

2. Selection of Reporting Threshold

In developing the threshold for landfills, we considered thresholds of 1,000, 10,000, 25,000, and 100,000 metric tons CO_2e of CH_4 generation at a landfill minus soil oxidation (''generation threshold'') or of CH_4 emissions from a landfill, minus oxidation, after any destruction of landfill gas at a combustion device (''emissions threshold'').

Table HH–1 of this preamble illustrates the emissions and facilities that would be covered under these various thresholds for MSW landfills. For landfills located at industrial facilities,[89] please refer to the threshold analyses for those sectors (e.g., food processing, ethanol, pulp and paper).

TABLE HH–1. THRESHOLD ANALYSIS FOR MSW LANDFILLS (OPEN AND CLOSED)

Threshold level	Total national emissions (metric tons CO_2e)	Total national facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e /year	Percent	Number	Percent
1,000 metric tons CO_2e (generation)	111,100,000	7800	110,800,000	99.7	6,830	88
1,000 metric tons CO_2e (emissions)	111,100,000	7800	110,800,000	99.7	6,827	88
10,000 metric tons CO_2e (generation)	111,100,000	7800	104,400,000	94	3,484	45
10,000 metric tons CO_2e (emissions)	111,100,000	7800	102,800,000	93	3,060	39
25,000 metric tons CO_2e (generation)	111,100,000	7800	91,100,000	82	2,551	33
25,000 metric tons CO_2e (emissions)	111,100,000	7800	82,400,000	74	1,926	25
100,000 metric tons CO_2e (generation)	111,100,000	7800	65,600,000	59	1,038	13
100,000 metric tons CO_2e (emissions)	111,100,000	7800	39,300,000	35	441	6

The proposed threshold for reporting emissions from MSW landfills is a generation threshold of 25,000 metric tons CO_2e (i.e., CH_4 generated at the landfill, minus oxidation in landfill cover soils). This threshold is consistent with thresholds for other source categories and covers over 70 percent of emissions from the source category. It strikes a balance between the goal of covering the majority of the emissions while avoiding a reporting burden for small MSW landfills and, especially, small, closed MSW landfills.

For a full discussion of the threshold analysis, please refer to the Landfills TSD (EPA–HQ–OAR–2008–0508–034). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

This section of the preamble describes the proposed methods for estimating CH_4 generation and emissions from landfills and for determining the quantity of landfill CH_4 destroyed.

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating emissions from landfills (e.g., 2006 IPCC Guidelines, U.S. GHG Inventory, CCAR, EPA Climate Leaders, EU Emissions Trading System, TCR, EPA's Landfill Methane Outreach Program, DOE 1605(b), Australia's National Mandatory GHG Reporting Program (draft), NSPS/NESHAP, WRI/WBCSD GHG Protocol, and National Council of Air and Stream Improvement). In general, these methodologies include three methods for monitoring emissions: The modeling method, the engineering method, and the direct measurement method.

Option 1. Modeling Method. The IPCC First Order Decay Model[90] in the 2006 IPCC Guidelines produces emissions estimates that reflect the degradation rate of wastes in a landfill. This method uses waste disposal quantities, degradable organic carbon, dissimilated degradable organic carbon, a decay rate, time lag before CH_4 generation, fraction of CH_4 in landfill gas, and an oxidation factor.

Option 2. Engineering Method. Direct measurement of collected landfill gas to determine CH_4 generation from landfills depends on two measurable parameters: The rate of gas flow to the destruction device; and the CH_4 content of the gas. These are quantified by directly measuring the flow rate and CH_4 concentration of the gas stream to the destruction device(s).

Option 3. Direct Measurement. Direct measurement methods for calculating CH_4 emissions from landfills include flux chambers and optical remote sensing.

Proposed Option. As part of this proposed rule, stationary fuel combustion emissions unrelated to the flaring of recovered landfill CH_4, and emissions from the use of auxiliary fuel to maintain effective operation of the flare (e.g., for pilot gas, or fuel used to supplement the heating value of the landfill gas occurring at the landfill), would be estimated and reported according to the proposed procedures in proposed 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources), which are discussed in Section V.C of this preamble.

In order to estimate CH_4 emissions from the landfill we propose a combination of Option 1 and Option 2.

Modeling method. In the proposed rule, all landfills would be required to

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[88] For the purposes of this rule, an open landfill is one that has accepted waste during the reporting year.

[89] As explained in sections III and IV of this preamble, many facilities reporting to the proposed rule will have more than one source category. In order to determine applicability, facilities must add the emissions from all source categories for which there are methods proposed in the proposed rule.

[90] The IPCC First Order Decay Model is available at *http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html.*

calculate CH_4 generation and emissions using the IPCC First Order Decay Model. The IPCC First Order Decay Model has two calculation options: A bulk waste option and a waste material-specific option. The proposed rule would require the use of the material-specific option for all industrial landfills, and for MSW landfills when material-specific waste quantity data are available, as this option is expected to provide more accurate emission estimates. However, the accuracy improvement is limited and at MSW landfills, material-specific waste quantity data are expected to be sparse, so use of the waste material-specific approach would not be mandated for all MSW landfills. Where landfills do not have waste material-specific data, the bulk waste option would be used.

We propose that the landfills use site-specific data to determine waste disposal quantities (by type of waste material disposed when material-specific waste quantity data are available) and use appropriate EPA and IPCC default values for all other factors used in the emissions calculation. To accurately estimate emissions using this method, waste disposal data are needed for the 50 year period prior to the year of the emissions estimate. Annual waste disposal data are estimated using receipts for disposal where available, and where unavailable, estimates based on national waste disposal rates and population served by the landfill.

Engineering method. For landfills with gas collection systems, it is also possible to estimate CH_4 generation and emissions using gas flow and composition metering along with an estimate of the landfill gas collection efficiency. We propose to require landfills that have gas collection systems to calculate their CH_4 generation (adjusted for oxidation) and emissions using both the IPCC First Order Decay Model (as described above), and the measured CH_4 collection rates and estimated gas collection efficiency. This proposal provides a means by which all landfills would report emissions and generation consistently using the same (IPCC First Order Decay Model) methodology, while also providing reporting of site-specific emissions and generation estimates based on gas collection data.

We propose that landfills with gas collection systems continuously measure the CH_4 flow and concentration at the flare or energy device. This monitoring option is more accurate than a monthly sample given variability in gas flow and concentration over time, and many landfills with gas collection systems already have such equipment in place.

We are seeking comment on monthly sampling of landfill gas CH_4 flow and concentration as an alternative to a continuous composition analyzer. For the monthly sampling alternative, a continuous gas flowmeter would still be required.

To estimate CH_4 emissions remaining in the landfill gas combustion exhaust of a destruction device, apply the DE of the equipment to the quantity of CH_4 collected as measured by the monitoring systems described above.

Calculating generation and emissions. CH_4 generation (adjusted for oxidation) is calculated by applying an oxidation factor to generated CH_4. For landfills without gas collection systems, the calculated value for CH_4 generation (adjusted for oxidation) is equal to CH_4 emissions. For landfills with collection systems, CH_4 generation is also calculated using both the IPCC First Order Decay model method and the gas collection data measurement method with a collection efficiency as explained above. CH_4 emissions are calculated by deducting destroyed CH_4 and applying an oxidation factor to the fraction of generated CH_4 that is not destroyed.

Direct Measurement Method. We also considered direct measurement at landfills as an option. The direct measurement methods available (e.g., flux chambers and optical remote sensing) are currently being used for research purposes, but are complex and costly, their application to landfills is still under investigation, and they may not produce accurate results if the measuring system has incomplete coverage.

We are considering developing a tool to assist reporters in calculating generation and emissions from this source category. We have reviewed tools for calculating emissions and emissions reductions from these sources, including IPCC's Waste Model, and National Council of Air and Stream Improvement's GHG Calculation Tools for Pulp and Paper Mills, and EPA's LandGEM, and are seeking comment on the advantages and disadvantages of using these tools as a model for tool development and on the utility of providing such a tool.

4. Selection of Procedures for Estimating Missing Data

Missing data procedures for landfills are proposed based on the monitoring methodology. In the case where a monitoring system is used, the substitute value would be calculated as the average of the values immediately proceeding and succeeding the missing data period. For prolonged periods of missing data when a monitoring system is used, or for other non-monitored data, the substitute data would be determined from the average value for the missing parameter from the previous year, or from equations specified in the rule (for waste disposal quantities). The proposed rule would require a complete record of all parameters determined from company records that are used in the GHG emissions calculations (e.g., disposal data, gas recovery data).

For purposes of the emissions calculation, we considered not deducting CH_4 destruction that was not recorded. However, not including CH_4 recovery could greatly overestimate a facility's emissions. On the other hand, allowing extended periods of missing data provides a disincentive to repairing the monitoring system.

5. Selection of Data Reporting Requirements

We propose that landfills over the threshold report CH_4 generation, CH_4 oxidation, CH_4 destruction (if applicable), and net CH_4 emissions on an annual basis, as calculated above using both the First Order Decay Model and, if applicable, gas flow data for landfills with gas collection systems. In addition to reporting emissions, input data needed to calculate CH_4 generation and emissions would be required to be reported. These data form the basis of the GHG emission calculations and are needed for EPA to understand the emissions data and verify the reasonableness of the reported data. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and HH.

6. Selection of Records That Must Be Retained

Records to be retained include information on waste disposal quantities, waste composition if available, and biogas measurements. These records are needed to allow verification that the GHG emission monitoring and calculations were done correctly. A full list of records to be retained onsite is included in proposed 40 CFR part 98, subparts A and HH.

II. Wastewater Treatment

1. Definition of the Source Category

An industrial wastewater treatment system is a system located at an industrial facility which includes the collection of processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from waters released from industrial processes. Industrial wastewater treatment systems may include a variety of processes, ranging from primary treatment for solids removal to secondary biological treatment (e.g., activated sludge, lagoons) for organics reduction to tertiary treatment for nutrient removal, disinfection, and more discrete filtration. In some systems, the biogas (primarily CH_4) generated by anaerobic digestion of organic matter is captured and destroyed by flaring and/or energy recovery. The components and configuration of an industrial wastewater treatment system are determined by the type of pollutants and contaminants targeted for removal or treatment. Industrial wastewater systems that rely on microbial activity to degrade organic compounds under anaerobic conditions are sources of CH_4.

CH_4 emissions from wastewater treatment systems are primarily a function of how much organic content is present in the wastewater system and how the wastewater is treated. Industries that have the potential to produce significant CH_4B emissions from wastewater treatment—those with high volumes of wastewater generated and a high organic wastewater load—include pulp and paper manufacturing, food processing, ethanol production, and petroleum refining.

Wastewater treatment also produces CO_2; however, with the exception of CO_2 from oil/water separators at petroleum refineries, this CO_2 is not counted in GHG totals as it is not considered an anthropogenic emission. Likewise, CO_2 resulting from the combustion of digester CH_4 is not accounted as an anthropogenic emission under international accounting guidance.

In 2006, CH_4B emissions from industrial wastewater treatment were estimated to be 7.9 million metric tons CO_2e.

The only wastewater treatment process emissions to be reported in this rule are those from onsite wastewater treatment located at industrial facilities, such as at pulp and paper, food processing, ethanol production, petrochemical, and petroleum refining facilities. POTWs are not included in this proposal because, as described in the Wastewater Treatment TSD (EPA–HQ–OAR–2008–0508–035), emissions from POTWs do not exceed the thresholds considered under this rule.

2. Selection of Reporting Threshold

A separate threshold is not proposed for emissions from industrial wastewater treatment system as these emissions occur in a number of facilities across a range of industries (e.g., pulp and paper, food processing, ethanol production, petrochemical, and petroleum refining). As described in Sections III and IV of this preamble, a facility may have more than one source category and emissions from all source categories for which there are methods (e.g., emissions from industrial wastewater treatment systems) must be included in the facility's applicability determination. Please see the preamble sections for the relevant sectors for more information on the applicability determination for your facility.

Despite the fact that we are not proposing a separate threshold for industrial wastewater systems, there is analysis in the Wastewater Treatment TSD on the types of industrial facilities that would meet thresholds at the 1,000, 10,000, 25,000 and 100,000 million metric tons CO_2e level based on emissions from wastewater alone. There is also a separate threshold analysis on POTWs.

For a full discussion of those threshold analyses, please refer to Wastewater Treatment TSD (EPA–HQ–OAR–2008–0508–035). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

For this proposal, we reviewed several protocols and programs for monitoring and/or estimating GHG emissions including the 2006 IPCC Guidelines, the U.S. GHG Inventory, CARB Mandatory GHG Emissions Reporting System, CCAR, National Council of Air and Stream Improvement, DOE 1605(b), EPA Climate Leaders, TCR, UNFCCC Clean Development Mechanism, the EU Emissions Trading System, and the New Mexico Mandatory GHG Reporting Program. These methodologies are all primarily based on the IPCC Guidelines.

Based on this review, we considered the following options.

Option 1. Modeling Method. This method involves the use of certain site-specific measured activity data and emission factors. The IPCC method, for example, uses wastewater flow, COD, and wastewater treatment system type to calculate CH_4 emissions from wastewater treatment.

Option 2. Direct Measurement. This method allows for site-specific measurements, but the methods available (e.g., flux chambers and open path methods) are currently being used only for research purposes, are complex and costly, and might not be accurate if the measuring system has incomplete coverage.

Proposed Methods. We propose that facilities use activity data, such as measured COD concentration, and operational characteristics (e.g., type of system), and the IPCC Tier 1 method to calculate CH_4 generation. To determine CH_4 destruction, we propose direct measurement of CH_4 flow to combustion devices. The proposed monitoring method uses a separate equation to estimate CO_2 from oil/water separators at petroleum refineries, based on California's AB32 mandatory reporting rule. This approach allows the use of default factors, such as a system emission factor, for certain elements of the calculation, and the use of site-specific data where possible.

CH_4 emissions from industrial wastewater treatment system components other than digesters. To estimate the amount of CH_4 emissions from industrial wastewater treatment, plant-specific values of COD would be determined by weekly sampling. The maximum amount of CH_4 that could potentially be produced by the wastewater under ideal conditions is calculated by multiplying the COD by the maximum CH_4 producing capacity of the wastewater, per the 2006 IPCC Guidelines. This value is then multiplied by a system-specific CH_4 conversion factor reflecting the capability of a system to produce the maximum achievable CH_4 based on the organic matter present in the wastewater.

CH_4 Generation from Anaerobic Digesters. If the wastewater treatment system includes an anaerobic digester, we propose that the CH_4 generation of the digester be measured continuously. Direct measurement to determine CH_4 generation from digesters depends on two measurable parameters: The rate of gas flow to the combustion device and the CH_4 content of the gas. These are quantified by direct measurement of the gas stream to the destruction device(s). The gas stream is measured by continuous metering of both flow and gas concentration. This continuous monitoring option is more accurate than a monthly sample given variability in gas flow and concentration over time, and many digesters already have such equipment in place.

We are also seeking comment on monthly sampling of digester gas CH_4 content as an alternative to a continuous composition analyzer. For the monthly CH_4 content sampling alternative, a continuous gas flow meter would still be required.

CH_4 Destruction. To estimate CH_4 destroyed at a digester, you would apply

the DE of the combustion equipment (lesser of manufacturer's specified DE and 0.99) to the value of CH_4 generated from anaerobic digestion estimated above.

CO_2 emissions from oil/water separators at petroleum refineries. To calculate CO_2 emissions from degradation of petroleum or impurities at oil/water separators at petroleum refineries, the volume of wastewater treated would be measured weekly and multiplied by the non-methane volatile organic carbon emission factor for the type of separator used, and an emission factor for CO_2 (mass of CO_2/mass of non-methane volatile organic carbon).

Total emissions. Total emissions from wastewater treatment are the sum of the CH_4 emissions (including undestroyed CH_4 from digesters), and CO_2 emissions.

Other Options Considered. Direct measurement is another option we considered but are not proposing in this rule. This method allows for site-specific measurements, but it is costly and might not be accurate if the measuring system has incomplete coverage. To be accurate, a direct measurement system would need to be complete both spatially (in that all emissions pathways are covered, not just individual pathways as is the case with anaerobic digesters, at which gas is commonly directly metered) and temporally (as emissions can vary greatly due to changes in influent and conditions at the facility).

We are considering developing a tool to assist reporters in calculating emissions from this source category. EPA has reviewed tools for calculating emissions from these sources, such as National Council of Air and Stream Improvement's GHG Calculation Tools for Pulp and Paper Mills, and is seeking comment on the advantages and disadvantages of using these tools as a model for tool development, and the utility of providing such a tool.

For additional information on the proposed method, please see the 2006 IPCC Guidelines,[91] the 2008 U.S. Inventory,[92] and the Wastewater Treatment TSD (EPA–HQ–OAR–2008–0508–035).

4. Selection of Procedures for Estimating Missing Data

On the occasion that a facility lacks data needed to determine the emissions from wastewater treatment over a period of time, we propose that the facility apply an average facility-level value for the missing parameter from measurements of the parameter preceding and following the missing data incident, as specified in the proposed rule. The proposed rule would require a complete record of all parameters determined from company records that are used in the GHG emissions calculations (e.g., production data, biogas combustion data).

For purposes of the emissions calculations, we considered not deducting CH_4 destruction that was not recorded. However, not including CH_4 destruction could greatly overestimate a facility's actual CH_4 emissions.

5. Selection of Data Reporting Requirements

EPA proposes that industrial wastewater treatment plants over the threshold report annually both CH_4 and CO_2 emissions from wastewater treatment system components other than digesters, and CH_4 generation and destruction at digesters. In addition to reporting emissions, generation, and destruction, input data used to calculate emissions from the wastewater treatment process would be required to be reported. These data form the basis of the GHG emission calculations and are needed for EPA to understand the emissions data and verify the reasonableness of the reported data.

A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and II.

6. Selection of Records That Must Be Retained

Records to be retained include information on influent flow rate, COD concentration, wastewater treatment system types, and digester biogas measurements. These records are needed to allow verification that the GHG emission monitoring and calculations were done correctly. A full list of records to be retained onsite is included in proposed 40 CFR part 98, subparts A and II.

JJ. Manure Management

1. Definition of the Source Category

A manure management system is a system that stabilizes or stores livestock manure, or does both. Anaerobic manure management systems include liquid/slurry handling in uncovered anaerobic lagoons, ponds, tanks, pits, or digesters. At some digesters, material other than manure is treated along with the manure. Manure management systems in which treatment is primarily aerobic include daily spread, solid storage, drylot, and manure composting. For the purposes of this rule, a manure management facility consists of uncovered anaerobic lagoons, liquid/slurry systems, pits, digesters, and drylots (including systems that combine drylot with solid storage) onsite manure composting, other poultry manure systems, and cattle and swine deep bedding systems. The manure management system does not include other onsite units and processes at a livestock operation unrelated to the stabilization and/or storage of manure.

When livestock manure are stored or treated, the anaerobic decomposition of materials in the manure management system produces CH_4, while N_2O is produced as part of the nitrogen cycle through the nitrification and denitrification of the organic nitrogen in livestock manure and urine. The amount and type of emissions produced are related to the specific types of manure management systems used at the farm and are driven by retention time, temperature, and treatment conditions.

Manure management also produces CO_2; however, this CO_2 is not counted in GHG totals as it is not considered an anthropogenic emission. Likewise, CO_2 resulting from the combustion of digester CH_4 is not accounted as an anthropogenic emission under international accounting guidance.

According to the 2008 U.S. Inventory, CH_4 emissions from manure management systems totaled 41.4 million metric tons CO_2e, and N_2O emissions were 14.3 million metric tons CO_2e in 2006; manure management systems account for 8 percent of total anthropogenic CH_4 emissions and 3 percent of N_2O emissions in the U.S.

Manure management systems which include one or more of the following components are to report emissions under this rule: Manure handling in uncovered anaerobic lagoons, liquid/slurry systems, pits, digesters, and drylots, including systems that combine drylot with solid storage. Emissions to be reported include those from the systems listed above, and also emissions from any high rise houses for caged laying hens, broiler and turkey production on litter, deep bedding systems for cattle and swine, and manure composting occuring onsite as part of the manure management system.

This source category does not include systems which consist of only components classified as daily spread, solid storage, pasture/range/paddock, or manure composting. For detailed descriptions of system types, please

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[91] 2006 IPCC Guidelines. Chapter 6: Wastewater Treatment and Discharge. (Volume 5 Waste.) Available at *http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/5_Volume5/V5_6_Ch6_Wastewater.pdf.*

[92] 2008 U.S. Inventory. Chapter 8: Waste. Available at *http://www.epa.gov/climatechange/emissions/usinventoryreport.html.*

refer to the Manure Management TSD (EPA–HQ–OAR–2008–0508–036).

A facility that is subject to the proposed rule only because of emissions from manure management would also report CO_2, CH_4, and N_2O emissions from the combustion of supplemental fuel in flares using the methods in proposed 40 CFR part 98, subpart C, but would not be required to report any other combustion emissions.

2. Selection of Reporting Threshold

In developing the threshold for manure management, we considered thresholds of 1,000, 10,000, 25,000, and 100,000 metric tons CO_2e of CH_4 generation and N_2O emissions at a manure management system (''generation threshold''), and CH_4 and N_2O emissions at manure management systems (''emissions threshold''). The ''generation threshold'' is the amount of CH_4 and N_2O that would be emitted from the facility if no CH_4 destruction takes place. This includes all CH_4 generation from all manure management system types, including digesters, and N_2O emissions. The ''emissions threshold'' includes the CH_4 and N_2O that is emitted to the atmosphere from these facilities. In the emissions threshold, CH_4 that is destroyed at digesters is taken into account and deducted from the total CH_4 generation calculated.

To estimate the number of farms at each threshold, EPA first developed a number of model farms to represent the manure management systems that are most common on large farms and have the greatest potential to exceed the GHG thresholds. Next, we used EPA'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 farm type. Finally, we combined the numbers of livestock required on each model farm 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 farm.

Table JJ–1 of this preamble presents the estimated head of livestock that would meet the thresholds evaluated for the highest GHG-emitting common manure management systems for beef (steers and heifers at a feedlot), dairy (cows at an uncovered anaerobic lagoon, heifers on dry lot without solids separation), swine (farrow to finish at an uncovered anaerobic lagoon), and poultry (layers and pullets at an uncovered anaerobic lagoon).

Other types of farms and manure management systems could require significantly higher head counts to meet the thresholds considered: Meeting the 25,000 tCO_2e threshold could require 978,000 head for beef on pasture, 13,000 head for some dairy liquid slurry systems, 171,000 head of farrow to finish swine using a deep pit for manure, and 47,028,300 broilers on litter. For more information on estimated head of livestock that would meet these thresholds for other manure management system types, please see the Manure Management TSD (EPA–HQ–OAR–2008–0508–036).

TABLE JJ–1. ESTIMATED HEAD OF LIVESTOCK TO MEET THRESHOLDS

	Threshold Levels (metric tons CO_2e)			
	1,000	10,000	25,000	100,000
	Total number of head to meet threshold			
Beef	3,500	35,500	89,000	356,000
Dairy	200	2,000	5,000	20,000
Swine	3,000	29,000	73,000	291,500
Poultry	39,500	358,000	895,000	3,580,000

Although data are available at the national level on the number of farms of certain sizes, most of the population sizes needed to meet these thresholds occur in the largest farm size categories, in which data are not sufficiently disaggregated to determine how many farms of such sizes exist. For example, the largest dairy farm size category for which data is available is ''1,000 head or more.'' The number of dairy farms with populations large enough to meet thresholds for 10,000 metric tons CO_2e (2,000 animals) and above therefore had to be estimated using expert judgment. It is estimated that at the proposed threshold, fewer than 50 manure management systems at beef, dairy, and swine operations would be required to report. Table JJ does not determine applicability alone, but rather serves as a ''screening'' guide in determining the approximate facility size that meets the applicability requirements. We are also seeking comment on the advantages and disadvantages of using additional screening tools such as a look-up table or computerized calculator to help owners or operators determine if they meet the reporting threshold. A table could be developed that indicated whether a facility had a sufficient number of animals to warrant further screening. If the initial screening through use of the table indicated that the facility may meet the reporting threshold a simple computerized calculator (e.g., web-based model) utilizing site-specifica data such as the type of manure management system and the average number of head, along with some other default data provided in look-up tables could be used to determine if a facility met the reporting threshold. Screening devices, if utilized, could assist owners or operators in determining if they are near the threshold for reporting and therefore potentially avoid costs incurred from monthly manure analysis proposed in the calculation method of the rule. More information and estimates based on existing farm size data are presented in the Manure Management TSD (EPA–HQ–OAR–2008–0508–036).

The proposed threshold for reporting emissions from manure management systems is the emission threshold of 25,000 metric tons CO_2e. More specifically, the CH_4 and N_2O emissions from manure management are summed to determine if a manure management system meets or exceeds the threshold. Facilities exceeding the threshold would report both of these GHG emissions. This threshold includes the largest emitters of GHG from this source category, while avoiding reporting from many small farms with less significant emissions. For a full discussion of the threshold analysis, please refer to Manure Management TSD (EPA–HQ–OAR–2008–0508–036). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

We are seeking comment on the option of using a generation threshold instead of the proposed emissions threshold. In the generation threshold option, the CH_4 generation (including CH_4 generated and later combusted) and the N_2O emissions from manure management are summed to determine if a manure management system meets or exceeds the threshold. Facilities exceeding the threshold would report both GHG generation and emissions. We estimated that this option would cover several farms with digesters that would not be covered in the emissions threshold option.

3. Selection of Proposed Monitoring Methods

Many domestic and international GHG programs provide monitoring guidelines and protocols for estimating emissions from manure management (e.g., the 2006 IPCC Guidelines, the U.S. GHG Inventory, DOE 1605(b), CARB Mandatory GHG Emissions Reporting System, CCAR, EPA Climate Leaders, TCR, UNFCCC Clean Development Mechanism, EPA AgSTAR, and Chicago Climate Exchange). These methodologies are all based on the IPCC Guidelines.

Based on the review of these methods, we considered the following options.

Option 1. Modeling Method. This method involves the use of certain site-specific measured activity data and emission factors. The IPCC method, for example, uses volatile solids, nitrogen excretion, climate data, and manure management system type to calculate CH_4 and N_2O emissions from manure management systems.

Option 2. Direct Measurement. This method allows for site-specific measurements, but the methods available (e.g., flux chambers and open path methods) are currently being used only for research purposes, are complex and costly, and might not be accurate if the measuring system has incomplete coverage.

Proposed option. We propose that facilities use activity data, such as the number of head of livestock, operational characteristics (e.g., physical and chemical characteristics of the manure, including measured volatile solids and nitrogen values, type of management system(s)), and climate data, with the IPCC method to calculate CH_4 and N_2O emissions, and measured values for gas destruction.

CH_4 emitted at manure management system types other than digesters. We propose that CH_4 emissions at manure management system components other than digesters be calculated using the IPCC methodology and measured volatile solids values.

We propose that the amount of volatile solids excreted be calculated using (1) calculation of manure quantity entering the system using livestock population data and default values for average animal mass and manure generation, and (2) monthly sampling and testing of excreted manure for total volatile solids content.

We are seeking comment on the option of using facility-specific livestock population and mass, and default values for volatile solids rate to estimate total volatile solids, instead of measured values. We are also seeking comment on whether a different sampling and testing frequency, such as quarterly, would be more appropriate than monthly.

The maximum amount of CH_4 that could potentially be produced by the manure under ideal conditions would be calculated by multiplying the volatile solids by the maximum CH_4-producing capacity of the manure (B0), a default value included in the GHG Inventory. A system-specific CH_4 conversion factor would then be applied to determine the amount of CH_4 produced by the specific system type.

CH_4 Generation at Digesters. If the manure management system includes a digester, we propose that the CH_4 generation of the digester be measured continuously. Direct measurement to determine CH_4 generation from digesters depends on two measurable parameters: The rate of gas flow to the combustion device, and the CH_4 content of the gas. These would be quantified by direct measurement of the total gas stream. We propose that the gas stream be measured by continuous metering of both flow and gas concentration. This continuous monitoring option is more accurate than a monthly sample given variability in gas flow and concentration over time, and many digesters already have such equipment in place.

We are also seeking comment on monthly sampling of digester gas CH_4 content as an alternative to a continuous composition analyzer. For the monthly CH_4 content sampling alternative, a continuous gas flow meter would still be required.

CH_4 *Destruction at Digesters.* To estimate CH_4 destruction at a digester, you would apply the DE of the destruction equipment (lesser of manufacturer's specified DE and 0.99) and the ratio of operating hours to reporting hours to the value of CH_4 generated from anaerobic digestion estimated above.

CH_4 Leakage at Digesters. To estimate CH_4 leakage from digesters, we propose that a default value for collection efficiency is applied to the measured quantity of CH_4 flow to a destruction device. We are seeking comment on the proposed method and on the proposed default collection efficiency values for estimating leakage from digesters.

CH_4 Emissions from Digesters. We propose that emissions from digesters be calculated as the sum of CH_4 that is not destroyed at the destruction device, and CH_4 that leaks from the digester.

N_2O Emissions. We propose that N_2O emissions be calculated using the IPCC methodology and measured nitrogen (N) values.

We propose that the amount of nitrogen entering the manure management system be measured through (1) calculation of manure quantity entering the system using livestock population data and default values for average animal mass and manure generation, and (2) monthly sampling and testing of excreted manure for total nitrogen content.

We are seeking comment on the option of using facility-specific livestock population and mass, and default values for nitrogen excretion rate to estimate total N, instead of measured values.

Each manure management system type has an associated default N_2O emission factor which would be applied to the amount of nitrogen managed by the system.

GHG Emissions. Reporters would be required to complete the following to calculate the emissions for reporting.

Estimate and report GHG emissions by adding the CH_4 emissions from manure management systems other than digesters, the N_2O emissions from manure management systems, and, for manure management systems which include digesters, the CH_4 emissions (monitored CH_4 generation at the digester minus CH_4 destruction at the digester) from the anaerobic digester.

Direct measurement is another option we considered but are not proposing in this rule. A direct measurement system must be complete both spatially (in that all emissions pathways are covered) and temporally (as emissions can vary greatly due to changes in population, diet, and conditions at the facility) and would hence be difficult and expensive to implement accurately.

We are considering developing a tool to assist reporters in calculating emissions from this source category. There are several existing tools for calculating emissions and emissions reductions from manure management systems, including EPA's FarmWare and CCAR's Livestock Project Reporting Protocol. We are seeking comment on the advantages and disadvantages of using such tools as a model for tool development and on the utility of providing such a tool.

The various approaches to monitoring GHG emissions, as well as specific cost information, are elaborated in the Manure Management TSD (EPA–HQ–OAR–2008–0508–036).

4. Selection of Procedures for Estimating Missing Data

On the occasion that a facility lacks sufficient data to determine the emissions from manure management over a period of time, we propose that the facility apply an average facility-level value for the missing parameter from measurements of the parameter preceding and following the missing data incident, as specified in the proposed rule. The proposed rule would require a complete record of all parameters determined from company records that are used in the GHG emissions calculations (e.g., historical livestock population data, biogas destruction data).

For emissions calculation purposes, EPA considered not deducting CH_4 recovery and destruction that was not recorded, but not including CH_4 destruction could greatly overestimate an entity's actual CH_4 emissions.

5. Selection of Data Reporting Requirements

EPA proposes that facilities report CH_4 and N_2O emissions, along with the input data to calculate these values. These data form the basis of the GHG emission calculations and are needed for EPA to understand the emissions data and verify the reasonableness of the reported data. A full list of data to be reported is included in proposed 40 CFR part 98, subparts A and JJ.

6. Selection of Records That Must Be Retained

Records to be retained include information on animal population, manure management system types, animal waste characteristics, and digester biogas measurements. These records are needed to allow verification that the GHG emission monitoring and calculations were done correctly. A full list of records to be retained onsite is included in proposed 40 CFR part 98, subparts A and JJ.

KK. Suppliers of Coal

1. Definition of the Source Category

Proposed 40 CFR part 98, subpart KK would require reporting by facilities or companies that introduce or supply coal into the economy (e.g., coal mines, coal importers, and waste coal reclaimers). These facilities or companies (in the case of coal importers and exporters) would report on the CO_2 emissions that would result from complete combustion or oxidation of the quantities of coal supplied. For completeness, this source category also includes coal exporters.

Facilities that use coal for energy purposes should refer to proposed 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). Facilities that use coal for non-energy uses (e.g., as a reducing agent in metal production such as ferroalloys, zinc, etc.) should refer to the relevant subparts of the proposed rule. Underground coal mine operators who are included in this subpart should also refer to proposed 40 CFR part 98, subpart FF (Underground Coal Mines) in order to account for any combustion and fugitive emissions separately, as described in Sections III and IV of this preamble. A description of the requirements related to the conversion of coal to liquid fuel is covered in Section V.LL of this preamble.

Coal is a combustible black or brownish-black sedimentary rock composed mostly of carbon and hydrocarbons. It is the most abundant fossil fuel produced in the U.S. Over 90 percent of the coal used in the U.S. is used to generate electricity. Coal is also used as a basic energy source in many industries, including cement and paper. In 2006, the combustion of coal for useful heat and work resulted in emissions of 2,065.3 million metric tons CO_2, or 29 percent of total U.S. GHG emissions.

The supply chain for delivering coal to consumers is relatively straightforward. It includes coal mines or importers, in some cases coal washing or preparation onsite or at dedicated offsite plants, and transport (usually by rail) to consumers. The U.S. typically produces nearly all of its domestic coal needs; in 2007, domestic coal production accounted for 97 percent of domestic coal consumption. A relatively small share of coal consumed in the U.S. (3 percent in 2007) is imported from other countries, and a small share of U.S. production is exported for use abroad (5 percent in 2007).

In determining the most appropriate point in the supply chain of coal for reporting potential CO_2 emissions, we considered the following criteria: An administratively manageable number of reporting facilities; complete coverage of coal supply as a group of facilities or in combination with facilities reporting under other subparts of the proposed rule; minimal irreconcilable double-counting of coal supply; and feasibility of monitoring or calculation methods.

We are proposing to include all active coal mines, coal importers, coal exporters, and reclaimers of waste coal as reporters under this subpart.

We are proposing to require all owners or operators of active underground and surface coal mines to report under proposed 40 CFR part 98, subpart KK. There were 1,365 active coal mines (both underground and surface mines) operating in the U.S. in 2007, according to the MSHA. Currently, coal mines routinely monitor coal quantity and coal quality data for use in coal sale contracts as well as for reporting requirements to various State and Federal agencies.

We are proposing that importers of coal into the U.S. report under proposed 40 CFR part 98, subpart KK. Reporting for coal importers is proposed at the company level, as opposed to the facility level, because the importers of record are typically companies, and these companies currently track and report imports. Most of the 36 million tons of coal that were imported to the U.S. in 2007 were used for power generation. A small number of electric utility companies were responsible for the large majority of coal imports in 2006.[93] In many cases, the importing companies also own and operate electricity generating or industrial facilities that would be included as covered facilities under other subparts of the proposed rule. Because these entities already collect much of this information, EPA believes that the reporting requirements for importers would impose a minimal additional burden.

We are proposing that exporters of coal report under proposed 40 CFR part 98, subpart KK. In 2007, 59.2 million tons of coal produced (mined) in the U.S. were exported. Coal exporters may include coal mining companies who directly sell their coal to entities outside the U.S., or other retailers who export the coal (typically via barge from one of several U.S. ports). Coal exports are included in proposed 40 CFR part 98, subpart KK so that the total supply of coal (and associated GHG emissions) into the U.S. economy is balanced against the coal that leaves the country. Typically, coal exporters characterize the quantity (tons) and heat value of the coal. Thus, this reporting requirement would impose a minimal additional burden on coal exporters.

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[93] In 2006, the eight largest coal-importing power generating companies accounted for 87 percent of total imported coal by electric utilities (FERC Form 423 and EIA 906). Approximately 80 percent of coal imports were used in the electricity sector in 2006.

We are proposing that reclaimers of waste coal report under proposed 40 CFR part 98, subpart KK. In some parts of the U.S., waste coal that was mined decades ago and placed in waste piles is now being actively recovered and sold to end users. Because this coal is technically not being ''mined'' but is nonetheless entering the U.S. economy for the first time, facilities that reclaim or recover such waste coal from waste coal piles and sell or deliver it to end-users are being included for reporting under proposed 40 CFR part 98, subpart KK as waste coal reclaimers. Because these facilities would need to collect data on the quantity and quality (e.g., heat value) of their product, this reporting requirement should impose a minimal additional burden on coal reclaimers.

We considered but are not proposing that facilities that convert coking coal into industrial coke and importers of coke report under proposed 40 CFR part 98, subpart KK. U.S. coke imports in 2007 constituted only 2.5 million tons (about 0.2 percent of total U.S. coal production) and can therefore be considered negligible. Most domestically consumed coal-based coke (87 percent) is derived from domestically-mined coal or imported coal, and therefore the inclusion of coal mines and coal importers in this subpart already provide for coverage of carbon contained in the coke (and the potential CO_2 emissions from oxidizing or combusting the coke). Only 14 percent of coal-based coke consumed domestically is imported directly as coke. Furthermore, coke production is an energy- and emissions-intensive process, and these facilities are likely to be above thresholds for the general stationary fuel combustion sources (proposed 40 CFR part 98, subpart C) and industrial process categories such as iron and steel, and ferro-alloys. Therefore, GHG emissions associated with the combustion or oxidation of coke imports and domestically produced coke would already be included in the actual GHG emissions reported under those subparts.

We considered but are not proposing that coal preparation plants located offsite from coal mines report the potential CO_2 emissions associated with their processed coal. Some of these facilities may be included as reporting facilities under proposed 40 CFR part 98, subpart C for direct emissions from combustion. An unknown but likely very small share of coal production annually requires additional preparation or washing at an offsite preparation plant. Typically, only the smaller mines do not do their preparation onsite. We are not requiring offsite coal preparation plants to report under this subpart because the potential CO_2 emissions from coal supplied by these facilities is already accounted for by reported data from coal mines, coal importers, and waste coal reclaimers.

Instead of requiring coal mines to report as coal suppliers, we also considered, but are not proposing, that rail operators report the quantity of coal they transport. We have determined that requiring reporting on coal transport would add complexity without increasing the accuracy of information on potential CO_2 emissions associated with the supply of coal to the U.S. economy. It is our understanding that, unlike coal mines or coal importers, coal transporters do not routinely collect information about the carbon content or heating value of the coal they are transporting, so such reporting requirements would add to the reporting burden. Furthermore, in the case of mine mouth power plants for which the coal does not travel via rail, rail transporters would miss this coal production entirely.

We request comment on the inclusion of active underground and surface coal mines, coal importers, coal exporters, and waste coal reclaimers, and the exclusion of offsite preparation plants, coke importers and coke manufacturing facilities, and coal rail transporters from reporting requirements under proposed 40 CFR part 98, subpart KK. For additional background information on suppliers of coal, please refer to the Suppliers of Coal TSD (EPA–HQ–OAR–2008–0508–037).

2. Selection of Reporting Threshold

In considering a threshold for coal suppliers, we considered the application of the following emissions-based thresholds for each affected company or facility under proposed 40 CFR part 98, subpart KK (e.g., coal mine, coal importer, coal exporter, or waste coal reclaimer): 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 per year. For coal suppliers, these thresholds would be applied to the CO_2 emissions that would result from complete combustion or oxidation of the coal produced or supplied into the U.S. economy, rather than the actual GHG emissions for the individual facilities or companies. To provide general information on how the thresholds would affect the coal industry, we used a weighted average carbon content of 1,130 lbs/short ton.[94] These thresholds translate into annual coal production for a single mine of 532 short tons, 5,321 short tons, 13,303 short tons, and 53,211 short tons, respectively.

Coal Mines. Table KK–1 of this preamble illustrates the coal mine emissions and facilities that would be covered under these various thresholds.

TABLE KK–1. THRESHOLD ANALYSIS FOR COAL MINES

Threshold level metric tons CO_2e/yr	Total 2007 national emissions (million metric tons CO_2e/yr)[1]	Total 2007 number of facilities in the U.S.	Emissions covered		Facilities covered	
			Million metric tons CO_2e/yr[2]	Percent	Number of facilities[3]	Percent of facilities
1,000	2,153	1,365	2,146	99.7	1,346	99
10,000	2,153	1,365	2,146	99.7	1,237	91
25,000	2,153	1,365	2,144	99.6	1,117	82
100,000	2,153	1,365	2,130	98.9	867	64

Source: EIA Table FE4 and 2007 MSHA database.

Notes:

(1) 2007 National Emissions (metric tons CO_2e) = 2007 Production × U.S. Weighted Average CO_2 content (4,143 lbs/short ton)/(2205 lbs/metric ton).

(2) Emissions covered (metric tons CO_2e) = sum of coal CO_2 emissions for all facilities with metric tons CO_2e production greater than the threshold.

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[94] Carbon content is found using the weighted average of CO_2 (lbs/MMbtu) from EIA Table FE4 along with the heat content (MMbtu/ton) and production (tons) from the 2007 MSHA database. The molecular mass ratio of carbon to CO_2 (12/44) is then used to find carbon content from the derived CO_2 (4,143 lbs/short ton).

(3) Facilities covered = total number of facilities with metric tons CO_2e production greater than the threshold.

For this rule, we propose to include all active underground and surface coal mines, with no threshold. Of the approximately 1,365 active coal mines operating in 2007, the 25,000 metric tons CO_2e threshold (corresponding to 1,140.8 million tons of coal production) would include the largest 1,117 coal mines and 99.6 percent of U.S. coal production. All active U.S. coal mines already report annual (and quarterly) coal production (based on aggregated daily production data) to MSHA. The additional reporting required under this proposal is the carbon content of the coal, which can be calculated using the coal's higher heating value (HHV) also referred to as the gross calorific value (GCV). All active U.S. coal mines already conduct daily proximate analysis to record the HHV for coal sales contracts. An alternative for coal mines with annual production lower than 100,000 short tons is offered in the proposed rule to estimate CO_2 emissions using HHV and default values, making this a very minimal additional reporting burden. Thus, we have determined that including all mines as reporters under proposed 40 CFR part 98, subpart KK would not significantly increase the burden on small coal mines. We are seeking comments on this conclusion.

Coal Importers. As noted above, the majority of imported coal is imported by power plants for steam generation of electricity, with the remainder imported by other sizeable industrial facilities. We propose that all coal importers report, with no threshold. Because most of the imported coal is brought into the U.S. by companies owning facilities that would already be required to report GHG data to EPA under other subparts of the proposed 40 CFR part 98, EPA believes that there would be a minimal incremental burden associated the inclusion of all importing companies. We are seeking comments on this conclusion.

Coal Exporters. Under proposed 40 CFR part 98, subpart KK, we are proposing that all coal exporting companies report, with no threshold. Coal exporters already collect information about the quantity and quality (e.g., heating value) of coal to be exported. Reporting to us under proposed 40 CFR part 98, subpart KK would therefore impose only minimal additional burden on these companies.

Waste coal reclaimers. Under proposed 40 CFR part 98, subpart KK, we are proposing all waste coal reclaimers report, with no threshold. Parties that recover this waste coal for sale to consumers already collect information about the quantity and quality (e.g., heating value) of coal to be sold. Reporting to us under proposed 40 CFR part 98, subpart KK would therefore impose only minimal additional burden on these facilities.

For a full discussion of the threshold analysis, please refer to the Suppliers of Coal TSD (EPA–HQ–OAR–2008–0508–037). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We are proposing the reporting of the amount of coal produced or supplied to the economy annually, as well as the CO_2 emissions that would result from complete oxidation or combustion of this quantity of coal.

The only GHG required to be reported under this subpart is CO_2. Combustion of coal may also lead to trace quantities of CH_4 and N_2O emissions.[95] Because the quantity of CH_4 and N_2O emissions are highly variable and dependent on technology and operating conditions in which the coal is being consumed (unlike CO_2), we are not proposing that coal suppliers report on these emission. We seek comment on whether or not EPA should use the national inventory estimates of CH_4 and N_2O emissions from coal combustion, and apportion them to individual coal suppliers based on the quantity of their products.

We are proposing that coal mines, coal importers, coal exporters, and reclaimers of waste coal use a mass-balance method to calculate CO_2 emissions. The mass balance approach is based on readily available information: The quantity of coal (tons), and the carbon content of the coal (as determined by the mine, importer, exporter, or waste reclaimer, according to the methodology described below). The formula is simple and can be automated. The mass-balance approach is used extensively in national GHG inventories, and in existing reporting guidelines for facilities, companies, and states, such as the WRI/WBCSD GHG Protocol.

We propose that coal suppliers be required to report both the total weight of coal produced or supplied annually (tons per year), as well as either the carbon content (carbon mass fraction) or coal HHV, which can be a proxy for carbon content. In practice, coal suppliers routinely and frequently monitor both the weight and energy content of coal for contractual purposes (e.g., daily measurements of tonnage and analyses of the BTU, sulfur, and ash content of coal) as well as for reporting requirements to various State and Federal agencies. We propose that all coal suppliers report these routinely-collected data, and use them as a basis for estimating the CO_2 emissions associated with the coal.

For the purpose of this calculation, we propose that larger coal mines (i.e., coal mines that produce over 100,000 short tons of coal per year) use mine-specific, carbon content values.

Generally, the carbon content of coal can be determined through one of two procedures. The most accurate method is to determine the coal's carbon content (carbon mass fraction) directly through ultimate analysis of the coal's chemical constituents. An alternative method is to measure the coal's energy content (HHV, which is often expressed in units of MMBTU per unit weight) and use it as an indicator of the coal's carbon content. This is done by establishing a statistically significant correlation between the coal's heating value and the carbon content of the coal, and using this correlation to estimate the carbon content (carbon mass fraction) of a given batch of coal with known heating value. For instance, a linear relationship between coal heating value and coal carbon content can be established. This alternative approach is convenient because heat value measurements of coal are taken routinely and frequently by coal mines, coal importers, coal exporters, and coal retailers.

For the purpose of proposed 40 CFR part 98, subpart KK, EPA proposes that coal mines that produce over 100,000 short tons of coal per year have two options for reporting the carbon content of their coal: (1) Daily measurements of coal carbon content through ultimate analyses (daily sampling and analyses, reported as annual weighted average), or (2) a combination of daily measurements of coal HHV through proximate analyses and monthly measurements of carbon content through ultimate analyses, using an established, statistically significant correlation to estimate the daily weighted average coal carbon content (mass fraction), as described in the rule. We propose that a minimum of one year of data be used to establish such a mine-specific statistically significant correlation between the coal carbon

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[95] CO_2, CH_4, and N_2O emissions from coal combustion 2065.3, 0.8, and 10.23 million metric tons CO_2e, respectively.

content (as measured by ultimate analyses) and coal heating value (as measured by proximate analyses). We request comment on this approach, including the minimum number of data points necessary to establish a statistically significant mine-specific relationship between coal carbon content and coal HHV, and how often and under what circumstances should the statistical relationship be reestablished. According to MSHA data, 706 mines produced over 100,000 short tons of coal during 2007 (52 percent of all mines), accounting for 98 percent of total production. We propose that a more stringent method for calculating carbon content be applied to these larger mines in order to reduce the uncertainty of the CO_2 data collected.

EPA proposes that coal mines with annual coal production less 100,000 short tons use either one of the above approaches for estimating carbon content, or use a third alternative. This alternative involves estimating the coal's carbon content based only on daily measurements of coal HHV through proximate analyses and a default CO_2 emissions factor provided as described in proposed 40 CFR part 98, subpart KK. EPA has concluded that this alternative is reasonable because it would reduce the sampling and analyses cost burden on these entities, yet would provide sufficient accuracy given their relatively small contribution to total U.S. coal supply. We request comments on this approach.

EPA proposes that all coal importers, coal exporters, and reclaimers of waste coal use any of three above approaches for estimating carbon content based on measurements per shipment in place of daily measurements if preferred. We seek comment on this measurement approach.

We propose that the ASTM Method D5373 should be used as the standard for all ultimate analyses.

We considered, but are not recommending, an option to allow all coal mines to use default coal carbon content values instead of site-specific values or measurements. Existing information available on the variability of carbon content for coal from USGS, the U.S. GHG Inventory, EIA's GHG Inventory, and the IPCC indicate that default values introduce considerable uncertainty into the emissions calculation. Given the large share of total GHG emissions represented by use of coal in the U.S. economy, we view the direct measurement or estimation of site-specific carbon content values as necessary. We seek comment on an appropriate approach for reporters—such as importers—who estimate a weighted annual average GCV according to specified methodology that is not listed with a corresponding default coal carbon content value in table KK–1 of this rule. Further information on various approaches to monitoring GHG emissions is elaborated in the Suppliers of Coal TSD (EPA–HQ–OAR–2008–0508–037).

4. Selection of Procedures for Estimating Missing Data

We have determined that some of the information to be reported by coal mines, coal importers, coal exporters, and waste coal reclaimers is routinely collected as part of standard operating practices (e.g., coal tonnage). For these cases, we expect no missing data would occur.

Typically, coal is weighed using automated systems on the conveyor belt or at the loadout facility. In general, the weighing and sampling of coal at coal mines are conducted at about the same time to ensure consistency between quantity and quality of coal. In this rule, EPA proposes that the most current version of NIST Handbook 44 published by Weights and Measures Division, National Institute of Standards and Technology be used as the standard practice for coal weighing. In cases where coal supply data are not available, reporters may estimate the missing quantity of coal supplied, using documentation for the quantity of coal received by end-users or other recipients. For any periods during which mine scales are not operational or records are unavailable, estimates of coal production at the mine may be estimated using an average of values of production immediately preceding and following the missing data period, or other standard industry practices, such as estimating the volume of coal transported by rail cars and coal density to estimate total coal weight in tons. For additional background information on coal weighing, please refer to the Suppliers of Coal TSD (EPA–HQ–OAR–2008–0508–037).

In cases where carbon content or HHV measurements are missing, reporters may estimate the missing value based on an weighted average value for the previous seven days.

5. Selection of Data Reporting Requirements

We propose that coal mines, coal importers, coal exporters, and waste coal reclaimers each report to us annually on the CO_2 emissions that would result from complete combustion or oxidation of coal produced during the previous calendar year.

Information from coal mines should be reported at the facility level, and should include mine name, mine MSHA identification number, name of operating company, coal production coal rank or classification (e.g., anthracite, bituminous, sub-bituminous, or lignite), facility-specific measured values of coal carbon content or HHV that are used to calculate CO_2 emissions, and the estimated CO_2 emissions (metric tons CO_2/yr).

Coal importers, coal exporters, and waste coal reclaimers should report company name and technical contact information (name, e-mail, phone).

Coal importers should report at the corporate level. Coal importers already measure coal quantity for each shipment entering the U.S. Importers generally conduct proximate analyses on each shipment to assure that coal quality meets the coal specification under contract. Some importers may also conduct ultimate analysis. Coal importers should report the quantity of coal imported, coal rank or classification (e.g., anthracite, bituminous, sub-bituminous, or lignite), country of origin, origin-specific measured values of coal carbon content and HHV that are used to calculate CO_2 emissions, and estimated CO_2 emissions.

Coal exporters should report, at the corporate level, the quantity of coal exported, coal rank or classification (e.g.anthracite, bituminous, sub-bituminous, or lignite), name and MSHA identification number of mine of origin, country of destination, mine-specific measured values of coal carbon content or HHV that are used to calculate CO_2 emissions, and estimated CO_2 emissions (metric tons CO_2/yr).

Waste coal reclaimers should report, at the facility level, the quantity of coal recovered or reclaimed (tons/yr), coal rank or classification (e.g., anthracite, bituminous, sub-bituminous, or lignite), name of mine of origin, state of origin, mine-specific measured values of coal carbon content or HHV that are used to calculate CO_2 emissions, and estimated CO_2 emissions.

A full list of data to be reported is contained in the rule. These data to be reported form the basis of calculating potential CO_2 emissions associated with the total supply of coal into the U.S. economy. Therefore, these data are necessary for us to understand the emissions data and to verify the reasonableness of the reported emissions.

We considered, but are not proposing an option in which we would obtain facility-specific data for coal production through access to existing Federal

Government reporting databases, such as those maintained by MSHA. We have determined that comparability and consistency in reporting processes across all facilities included in the entire rule is vital, particularly with respect to timing of submission, reporting formats, QA/QC, database management, missing data procedures, transparency and access to information, and recordkeeping. In addition, EPA's methodological approach requires information that is not currently reported to Federal agencies, such as facility-specific information on coal quality (e.g., coal carbon content or heating value).

6. Selection of Records That Must Be Retained

A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and KK. EPA proposes that the following records specific to suppliers of coal be kept onsite: Daily production of coal, annual weighted average of coal carbon content values (if measured), annual weighted average of coal HHV, calibration records of any instruments used onsite (e.g., if coal analyses are done onsite), and calibration records of scales or other equipment used to weigh coal.

These records consist of data that are directly used to calculate the potential CO_2 emissions reported. We have concluded that these records are necessary to enable verification that the GHG emissions monitoring and calculation were done correctly.

LL. Suppliers of Coal-Based Liquid Fuels

1. Definition of the Source Category

We are proposing to include facilities that produce coal-based liquids as well as importers and exporters of coal-based liquids in this source category. Owners and operators of coal-to-liquids facilities, or ''producers'', importers, and exporters would report on the CO_2 emissions that would result from complete combustion or oxidation of the quantities of coal-based liquids supplied to or exported from the U.S. economy. Producers would report at the facility level; importers and exporters would report at the corporate level.

The carbon in coal-based liquids would already be captured in the reporting from domestic coal suppliers and importers, but we believe that it is important for climate policy development to have additional information on a unique and potentially growing source of liquid fuels. As discussed in Sections III and IV of this preamble, emissions resulting from the combustion and other uses of coal-based liquids, as well as emissions generated in the production of coal-based liquids, are addressed in other sections of the preamble, particularly Section V.C of this preamble (General Stationary Fuel Combustion Sources), Section V.D (Electricity Generation), and Section V.FF (Underground Coal Mines).

The output fuels from coal-to-liquids processes are compositionally similar to standard petroleum-based products e.g., gasoline, diesel fuel, jet fuel, light gases etc. The most common processes for converting coal to liquids are direct and indirect liquefaction. In the direct process, coal is processed directly to liquid. In the indirect process, coal is first gasified, and then liquefied.

Once manufactured, the supply chain for coal-based liquids to consumers is basically the same as it is for refined petroleum products. Liquid fuels are moved from the manufacturing facility to a terminal, at which point they may be blended or mixed with other products, before entering the downstream distribution chain. Imported coal-based liquids would enter the U.S. in the same way that refined and semi-refined petroleum products enter the country. In determining the most appropriate point in the supply chain of coal-based liquids, we followed the decision-making process applied to suppliers of petroleum products discussed in Section V.MM of this preamble, and selected coal-to-liquids facilities (analogous to refineries), and importers and exporters. For further information, see the Coal to Liquids TSD (EPA–HQ–OAR–2008–0508–038). We request comment on the approach of establishing a separate source category and subpart for suppliers of coal-based liquids, and the selection of coal-to-liquids facilities and corporate importers and exporters of coal-based liquids. We also request comment on whether or not importers of liquid-based fuels are likely to have the necessary information with which to distinguish coal-based liquids from conventional petroleum-based liquids.

2. Selection of Reporting Threshold

In developing the threshold for suppliers of coal-based liquids, EPA considered the emissions-based threshold 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 per year, but was limited by the fact that there are very few existing facilities. According to DOE, there is one facility operating in the world, one U.S. facility in the engineering phase, and thirteen facilities proposed in the U.S.[96] Given that conversion of coal to liquids is a highly energy intensive process that is viable only on a large scale, we propose that any coal-to-liquids facility operating in the U.S. would be required to report.

We also propose that all importers and exporters of coal-based liquids report under this rule. While the number of existing importers and exporters is very small in comparison to importers and exporters of petroleum products, importers of coal-based liquids would be required to track fuel quantities as part of routine business operations, and report to DOE and other Federal agencies.

For further information, see the Coal to Liquids TSD (EPA–HQ–OAR–2008–0508–038). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

We are proposing that producers, importers, and exporters of coal-based liquids calculate potential CO_2 emissions associated with coal-based liquids on the basis of a mass balance approach. Under this approach, CO_2 emissions would be determined by applying a carbon content value to the quantity of each coal-based liquid supplied. The formulae are simple and can be automated. For carbon content, reporters can either use the default CO_2 emission factors for standard petroleum-based fuels in proposed 40 CFR part 98, subpart MM or develop their own factors.[97] Reporters that choose to substitute their own batch- or facility-specific values for density and carbon share of individual coal-based liquids, and develop their own CO_2 emission factors, must do so according to the proposed ASTM standards and procedures discussed in proposed 40 CFR part 98, subpart MM. While carbon content of coal-based liquids may differ from petroleum products, we believe the default emission factors for petroleum products in proposed 40 CFR part 98, subpart MM can be used for estimating emissions from coal-based liquids. We request comment on this approach, the appropriateness of the proposed default CO_2 emission factors, and ways to improve these default values. We also

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[96] Coal Conversion—Pathway to Alternate Fuels. C. Lowell Miller. 2007 EIA Energy Outlook Modeling and Data Conference. Washington, DC, March 28, 2007.

[97] For a discussion of the benefits and disadvantages of default carbon factors versus direct measurement see Section V.MM.3 of this preamble.

request comment on the appropriateness of the proposed sampling and analysis standards and methods for developing batch- or facility-specific CO_2 emission factors, especially the methods for determining carbon share.

4. Selection of Procedures for Estimating Missing Data

We have determined that the information to be reported by suppliers of coal-based liquids is routinely collected by facilities and entities as part of standard operating practices, and therefore 100 percent data availability would be required. Typically, coal-based liquids would be metered directly at multiple stages. In cases where metered data are not available, reporters may estimate the missing volumes based on contracted maximum daily quantities and known conditions of receipt and delivery during the period when data are missing.

5. Selection of Data Reporting Requirements

We propose that producers, importers, and exporters report CO_2 emissions directly to EPA on an annual basis. Suppliers would report potential CO_2 emissions disaggregated by fuel types.

We considered but did not propose an option in which we would obtain facility-specific data for coal-based liquids through access to existing Federal government reporting databases, such as those maintained by EIA. EPA believes that comparability and consistency in reporting processes across all facilities included in the entire rule are vital, particularly with respect to timing of submission, reporting formats, QA/QC, database management, missing data procedures, transparency and access to information, and recordkeeping.

6. Selection of Records That Must Be Retained

A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and LL.

MM. Suppliers of Petroleum Products

1. Definition of the Source Category

We are proposing that refineries as well as importers and exporters of petroleum products be included in this source category. Owners or operators of petroleum refineries, or ‘‘refiners,’’ and importers that introduce petroleum products into the U.S. economy would be required to report on the CO_2 emissions associated with the complete combustion or oxidation of their petroleum products. Additionally, both refiners and importers would be required to report on biomass components of their petroleum products as well as NGLs they supply to the economy, and refiners would be required to report on certain types of feedstock entering their facility. Refiners would report at the facility level, and importers would report at the corporate level. Exporters of petroleum products are also included in this source category in order for us to appropriately account for petroleum products that are produced but not consumed in the U.S. and therefore do not result in direct CO_2 emissions in the U.S. Exporters would report on the petroleum products and NGLs they export, including the biomass components of the petroleum products, at the corporate level.

End users of petroleum products are addressed in other sections of this preamble, such as Section V.C (General Stationary Fuel Combustion Sources), and direct, onsite emissions at petroleum refineries are covered in Section V.Y of this preamble.

The total estimated GHG emissions resulting from the combustion of petroleum products in the U.S. in 2006 was 2,417 million metric tons CO_2e, according to the 2008 U.S. GHG Inventory. It is estimated that 75 percent of the combustion-related CO_2 emissions from petroleum use in the U.S. comes from the transportation sector. The next largest sector is industrial use (15 percent), and the commercial, residential, and electricity generation sectors make up the remainder.

Petroleum products are ultimately consumed in one of two ways: Either through combustion for energy use, or through a non-energy use such as petrochemical feedstocks or lubricants. Combustion of petroleum products produces CO_2 and lesser amounts of CH_4 and N_2O, which are in almost all cases emitted directly into the atmosphere. Some non-energy uses of fuels, such as lubricants, also result in oxidation of carbon and CO_2 emissions. This process may occur immediately upon first use or, in the case of biological deterioration, over time. Carbon in other petroleum products, such as asphalts and durable plastics, may remain un-oxidized for long periods unless burned as fuel or incinerated as waste.

The following list, while not comprehensive, illustrates the types of products that EPA considers to fall under the category of petroleum products:

- Motor vehicle and nonroad gasoline and diesel fuels.
- Jet fuel and kerosene.
- Aviation gasoline.
- Propane and other LPGs.
- Home heating oil.
- Residual fuel oil.
- Petrochemical feedstocks.
- Asphalt.
- Petroleum coke.
- Lubricants and waxes.

Reporting Parties. When considering the extent of the definition of this source category and who should be required to report under this rule, our approach was first to identify all parties within the petroleum product supply chain. We considered parties that function primarily in upstream petroleum production, such as oil drillers and well owners, as well as petroleum refiners and importers of refined and semi-refined products. We also considered parties located even further downstream, such as terminal operators, oxygenate blenders of transportation fuel, blenders of blendstock, transmix processors, and retail gas station owners. In addition, we considered pipeline owners and operators.

As discussed earlier in this preamble, one of our objectives when determining which entities would fall within a source category was to identify logical data reporting points or groups of facilities that were relatively small in number but that could provide a comprehensive set of data for the particular source category. Of all the parties that make up the petroleum products supply chain, we have concluded that petroleum refiners[98] and importers and exporters of semi-refined and refined petroleum products are the most appropriate parties to report to EPA under this source category and that the data they can report would be comprehensive.

There are approximately 150 operating petroleum refineries in the U.S. and its territories. Our thresholds analysis in Section V.MM.2 of this preamble, however, only reflects data on the 140 refineries that reported atmospheric distillation capacity to EIA (at DOE) in 2006. Petroleum products from these refineries account for approximately 90 percent of U.S. consumption. Given the coverage provided by a relatively small number of facilities, we propose that all refiners be subject to the reporting requirements for petroleum product suppliers and that they report to EPA on a facility-by-facility basis. For refiners that trade semi-refined and refined petroleum products between facilities, leading to a

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[98] A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

possible risk of double-counting in coverage, we are proposing a straight-forward accounting method in Section V.MM.5 of this preamble to address this possibility.

To account for refined and semi-refined petroleum products that are not produced at U.S. refineries, we are proposing to include importers under this source category. Importers currently report to EPA on petroleum products designated for transportation or non-road mobile end-uses. This rule would include all importers regardless of end-use designations. The number of importing companies varies from year to year, but it is typically on the order of 100 to 200.

We are also proposing to include under this source category exporters of refined and semi-refined petroleum products in order to have information on petroleum products that are produced but not consumed in the U.S. The rationale to include reporting from exporters is to be able to account for petroleum products that are consumed in other countries and that do not contribute to direct CO_2 emissions in the U.S.

Many refiners are also importers and exporters of petroleum products. EPA is proposing that such refiners separately report data on the petroleum products that they produce on a facility-by-facility basis and report at a corporate level the petroleum products they import or export. The rationale for this separate reporting is that we are generally proposing coverage at the facility level where feasible (e.g., refineries) and proposing corporate reporting only where facility-level coverage may not be feasible (e.g., importers and exporters). In addition, the separation simplifies reporting in cases where a company that owns or operates multiple refineries may have a consolidated arrangement for imports of refined and semi-refined products destined for its refineries and for other consumers, or for exports.

We considered but are not proposing to include parties that are involved in upstream petroleum production. We believe the number of domestic oil drillers and well owners is prohibitively large and represents only a portion of the amount of crude petroleum that is processed into finished products to be used in the U.S.

We are not proposing to include retail gas station owners and oxygenate blenders to report to EPA as suppliers of petroleum products. Retail gas station owners and oxygenate blenders mostly handle transportation fuel and fuel used in small engines. Because we are interested in GHG emissions from all petroleum products combusted or consumed in the U.S. and can obtain information on such products on a more aggregated basis directly from refiners and importers, we are proposing to exclude retail gas station owners and oxygenate blenders from reporting under this rule.

We are not proposing to include operators of terminals or pipelines, blenders of blendstocks, or transmix processors in this source category because we believe that refiners and importers can provide comprehensive information on petroleum products supplied in the U.S. with a lower risk of double-counting petroleum products. A given quantity of refined or semi-refined petroleum product may pass between multiple terminals and blending facilities, so asking terminal or pipeline operators, blenders of blendstock, or transmix processors to report information on incoming and outgoing products would likely result in unreliable data for estimating GHG emissions from petroleum products.[99]

Liquid fossil fuel products can be derived from feedstocks other than petroleum crude, such as coal and natural gas. Suppliers of coal-based products are covered under Section V.LL of this preamble, Suppliers of Coal-Based Liquid Fuels. Primary suppliers of natural gas-based products are covered in Section V.NN of this preamble, Suppliers of Natural Gas and Natural Gas Liquids. We are proposing to require all reporters in this source category to report data on the NGLs they supply to or export from the economy because these products may not currently be captured under Section V.NN of this preamble, Suppliers of Natural Gas and NGLs. The natural-gas related reporting requirements are discussed in Section V.MM.5 of this preamble.

This section of the preamble is focused on suppliers of petroleum products, so EPA is not proposing to include primary[100] suppliers of renewable fuels, such as fuel derived from biomass like grains, animal fats and oils, or waste, under this source category. However, as described in Section IV.B of this preamble (Reporting by fuel and industrial gas suppliers), we note that we are not proposing to require suppliers of biomass-based fuels to report on their products anywhere under this rule, except as discussed below for petroleum suppliers, due to a longstanding accounting convention adopted by the IPCC, the UNFCCC, the U.S. GHG Inventory, and many other State and regional GHG reporting programs where emissions of CO_2 from the combustion of renewable fuels are distinguished from emissions of CO_2 from combustion of petroleum or other fossil-based products. Under such convention, potential emissions from the combustion of biomass-based fuels are accounted for at the time of feedstock harvest, collection, or disposal, not at the point of fuel combustion. Nonetheless, we seek comment on this approach.

Certain petroleum products can be co-processed or blended with renewable fuels. We are proposing a method in Section V.MM.5 of this preamble whereby petroleum product suppliers report data that allows EPA to distinguish between the biomass and fossil fuel-based carbon in their products.

2. Selection of Reporting Threshold

In assessing the appropriateness of applying a threshold to refiners (at the facility level) and importers (at the corporate level), we calculated the volume of finished gasoline that would contain enough carbon that, when combusted or oxidized, would produce 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. We took the volume of finished gasoline as an example of how much of a refined or semi-refined product would result in a given level of CO_2 emissions. These data are summarized in Table MM–1 of this preamble.

TABLE MM–1. THRESHOLD ANALYSIS FOR FINISHED GASOLINE

Threshold level metric tons CO_2/yr	Total volume of gasoline bbls/yr
1,000	2,564
10,000	25,641
25,000	64,103
100,000	256,410

Based on the calculations in Table MM–1 of this preamble and data on the annual volume of petroleum products that refiners and importers are currently reporting to the EIA, EPA estimated the number of refineries and importers that would meet each of the four selected threshold levels. The results of this analysis are summarized below.

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[99] See Section V.MM.3 of this preamble regarding a method for accounting for trade between refineries.

[100] Refiners, exporters, and importers of petroleum products could, in some cases, be suppliers of renewable fuels but their supply of renewable fuels is not the focus of this subpart.

Refineries. Data on the typical production levels for refineries [101] demonstrate that each of the thresholds considered would cover all domestic refineries (see Table MM–2 of this preamble). This conclusion is based on the result that all refineries would exceed the thresholds for gasoline alone, and therefore would also exceed the thresholds for all products combined. For this reason, we are proposing to cover all petroleum refineries.

TABLE MM–2. THRESHOLD ANALYSIS FOR REFINERIES

Threshold level metric tons CO_2e/yr	Total national emissions [1][2] metric tons CO_2/yr	Total number of facilities [3]	Emissions covered		Facilities covered	
			Metric tons CO_2/yr	Percent	Number	Percent
1,000	2,447,738,368	140	2,447,738,368	100	140	100
10,000	2,447,738,368	140	2,447,738,368	100	140	100
25,000	2,447,738,368	140	2,447,738,368	100	140	100
100,000	2,447,738,368	140	2,447,738,368	100	140	100

[1] These constitute total emissions from all petroleum products ex refinery gate. The total includes only CO_2 emissions.
[2] Estimated CO_2 emissions for all refineries are based on applying product-specific default carbon contents to production of each product.
[3] This number represents the total number of refineries that reported atmospheric distillation capacity to EIA in 2006.

Small Refiners. In recent EPA fuel rulemakings, we have provided temporary exemptions from our regulations for small refiners, defined as producers of transportation fuel from crude oil that employed an average of 1,500 people or fewer over a given one-year period and with a corporate-average crude oil capacity of 155,000 barrels per calendar day or less. Such small refiner exemptions were provided to allow small refiners extra time to meet standards or comply with new regulations. This exemption was based on an assumption that to require small refiners to comply with new regulations on the same schedule as larger refiners would put them at a disadvantage if required to seek the same capital and administrative resources being sought by their larger competitors. Because of the nature of this reporting rule, however, we are not proposing any temporary exemptions for small refiners. We do not believe complying with this rule will require additional resources that might put small refiners at an unfair disadvantage. All refiners would already be reporting data to EPA, regardless of size, because all refineries meet the proposed reporting threshold in proposed 40 CFR part 98, subpart Y for direct onsite emissions.

Importers. Data on importers of petroleum products in 2006, the most recent year available, show that 78 percent of the importing companies exceeded the 25,000 metric tons CO_2e/yr reporting threshold and that some importing companies did not meet the 1,000 metric tons CO_2e/yr threshold (see Table MM–3 of this preamble). While 22 percent of importers supplied less than the amount of products that, when combusted or oxidized, would have resulted in 25,000 metric tons CO_2/yr, data on the amount and types of petroleum products is information that all importers maintain as part of their normal business operations. Therefore we believe the burden of reporting the required information listed in Section V.MM.5 of this preamble is minimal since no additional monitoring equipment has to be installed to comply with this rule. In addition, the quantity of products imported by a company may vary greatly from year to year. Furthermore, our proposed definition for petroleum products for importers and exporters in Subpart A excludes asphalt and road oil, lubricants, waxes, plastics, and plastic products. For these reasons, we are proposing that all importers of petroleum products be required to report to EPA, and we seek comment on our proposed definition of petroleum products as it applies to importers.

TABLE MM–3. THRESHOLD ANALYSIS FOR IMPORTERS

Threshold level metric tons CO_2e/yr	Total national emissions [1] metric tons CO_2/yr	Total number of importers	Emissions covered		Companies covered	
			Metric tons CO_2/yr	Percent	Number	Percent
<1000	393,294,390	224	393,294,390	100	224	100
1,000	393,294,390	224	393,291,916	>99.9	219	98
10,000	393,294,390	224	393,171,144	>99.9	193	86
25,000	393,294,390	224	392,895,841	99.9	175	78
100,000	393,294,390	224	389,628,252	99	120	54

[1] These constitute total emissions from all product imports. Analysis is based on EIA's Company Reports for 2006.

Exporters. Due to the limited availability of export data, EPA did not conduct a threshold analysis for petroleum products exporters. However, based on the type of information that exporters must maintain as part of their normal business operations, we believe that the incremental burden of reporting this information to EPA would be minimal. Considering this information and the importance of being able to account for petroleum products produced but not combusted or oxidized in the U.S., EPA is proposing that all exporters report on their exported petroleum products. Furthermore, our proposed definition for petroleum products for importers and exporters in Subpart A excludes asphalt and road oil, lubricants, waxes, plastics, and plastic products. We seek comment on this proposal.

De Minimis Exports and Imports. We are seeking comment on whether or not to establish a de minimis level, either in terms of total product volume or potential CO_2 emissions, to eliminate

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[101] To simplify our reporting threshold analysis, EPA omitted roughly 10 refineries that meet our definition of a petroleum supplier but did not report any atmospheric distillation capacity to EIA.

any reporting burden for parties that may import or export a small amount of petroleum products on an annual basis. We also note that in the proposed rule some importers and exporters may not be required to report their onsite combustion, process, and/or fugitive emissions under other sections of the proposed rule because their combined emissions do not meet the applicable thresholds.

For a full discussion of the threshold analysis, please refer to the Suppliers of Petroleum Products TSD (EPA–HQ–OAR–2008–0508–039). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Rather than directly measuring emissions from the combustion or consumption of their products, suppliers of petroleum products would need to estimate the potential emissions of their non-crude feedstocks and products based on volume and characteristic information. Therefore product volume metering and sampling would be of utmost importance to accurately calculate potential CO_2 emissions.

Volume measurement. EPA is proposing to require specific industry-standard test methods for flow meters and tank gauges for measuring volumes of feedstocks and products. For ultrasonic flow meters, we propose to require the test method described in AGA Report No. 9 (2007); for turbine meters, American National Standards Institute, ANSI/ASME MFC–4M–1986; for orifice meters, American National Standards Institute, ANSI/API 2530 (also called AGA–3) (1991); and for coriolis meters, ASME MFC–11 (2006). For tank gauges, we propose to require the following test methods: API–2550: Measurements and Calibration of Petroleum Storage Tanks (1965), API MPMS 2.2: A Manual of Petroleum Measurement Standards (1995), or API–653: Tank Inspection, Repair, Alteration and Reconstruction, 3rd edition (2008).

We propose that all flow meters and tank gauges must be calibrated prior to monitoring under this rule using a method published by a consensus standards organization (e.g., ASTM, ASME, American Petroleum Institute, or NAESB), or using calibration procedures specified by the flow meter manufacturer. Product flow meters and tank gauges would be required to be recalibrated either annually or at the minimum frequency specified by the manufacturer.

Carbon content determination. To translate data on petroleum product, NGLs, and biomass types and quantities into estimated potential GHG emissions, it is necessary either to estimate or measure the carbon content for each product type. For this proposal, we reviewed the existing CO_2 emission factors developed by EIA and used in the U.S. GHG Inventory, and we researched the sampling and test methods that would be required for direct measurement of carbon content by reporters.

We also considered the benefits and disadvantages of using default carbon content factors and of using direct measurements of carbon content. Default CO_2 emission factors have been used extensively in the U.S. GHG Inventory, in inventories of other nations, and in corporate reporting guidance; they are simple and cost effective for evaluating GHG emissions from common classes of biomass and fossil fuel types (e.g., ethanol, motor gasoline, jet fuel, distillate fuel, etc). It is also possible to combine default CO_2 emission factors to develop alternative factors for fuel reformulations by averaging according to weight. Some products, however, can have multiple chemical compositions due to different feedstock, blending components, and/or refinery processes, which can lead to variations in carbon content. Default CO_2 emission factors for common chemical compositions of common products cannot account for the full variability of carbon content in petroleum, natural gas, and biomass products.

Direct measurements would provide the most accurate determination of carbon content. It is relatively expensive, however, to design and implement a program for regular sampling and testing for carbon content across the variety of products produced at refineries. Many products are homogeneous because they must meet ''minimum'' specifications (e.g., jet fuel), and the use of direct measurements may not lead to noticeable improvements in accuracy over default CO_2 emission factors.

Based on this information, we are proposing that for purposes of estimating emissions, reporters could either use the default CO_2 emission factors for each product type published in proposed 40 CFR part 98, subpart MM or, in the case of petroleum products and NGLs, develop their own factors. Reporters that choose to substitute their own values for density and carbon share of individual petroleum products and NGLs, and develop their own CO_2 emission factors would be required to sample each product monthly for the reporting year and to test the composite sample at the end of the reporting period using ASTM D1298 (2003), ASTM D1657–02(2007), ASTM D4052–96(2002)el, ASTM D5002–99(2005), or ASTM D5004–89(2004)el for density, as appropriate, and ASTM D5291(2005) or ASTM D6729–(2004)el for carbon share, as appropriate (see Suppliers of Petroleum Products TSD (EPA–HQ–OAR–2008–0508–039)). For suppliers of seasonal gasoline, reporters would be required to take a sample each month of the season and test the composite sample at the end of the season.

We request comment on this approach. We request comment on whether reporters should be allowed to combine default CO_2 emission factors to develop alternative factors for fuel reformulations according to the volume percent of each fuel component, and if so using what methodology. We also request comment on the appropriateness and adequacy of the proposed default CO_2 emission factors—including factors for biomass products—and ways to improve these default values. For full documentation of the derivation of the proposed default factors, please refer to the Suppliers of Petroleum Products TSD (EPA–HQ–OAR–2008–0508–039).

In addition, we request comment on the appropriateness of the proposed sampling and analysis standards and methods for developing CO_2 emission factors for petroleum products and NGLs, especially the methods for determining carbon share. Specifically, we seek comment on specific ASTM or other industry standards that would be more appropriate for sampling petroleum products and NGLs to determine carbon share. Finally, we request comment on potential methods to determine carbon share of biomass products.

The various approaches to monitoring GHG emissions are elaborated in the Suppliers of Petroleum Products TSD (EPA–HQ–OAR–2008–0508–039).

4. Selection of Procedures for Estimating Missing Data

Under this proposal, we are suggesting methods for estimating data that may be missing from different source categories for various reasons. Petroleum product suppliers would need to estimate any missing data on the amount of petroleum products or NGLs supplied or exported, and the quantity of the crude and non-crude feedstocks, including biomass, consumed. In most cases, the source category would be missing data due to monitoring equipment malfunction or shutdown.

We have determined that the information to be reported by petroleum fuel suppliers is collected as part of standard operating practices, and expect that any missing data would be negligible. Typically, products are metered directly at multiple stages, and billing systems require rigorous reconciliation of data. In cases where metered data are not available, we are proposing that reporting parties may estimate the missing volumes based either on the last valid data point they recorded or on an average of two valid data points based on their established procedures for purposes of product tracking and billing. We seek comment on the appropriateness and adequacy of our proposed procedures for estimating missing data. Petroleum product suppliers reporting under this rule would be required to keep sufficient records to verify any volume estimates (see Section V.MM.6 of this preamble).

5. Selection of Data Reporting Requirements

We are proposing that suppliers of petroleum products be required to report the type, volume, and CO_2 emissions associated with the complete combustion or oxidation of each individual petroleum product and NGL they supply to the economy, export, or use as a feedstock annually. We are also proposing to require reporting on the total CO_2 emissions of all products they supply to the economy annually, minus any emissions associated with non-crude feedstocks, including biomass, and renewable fuel blended in a petroleum product. Additionally, we are proposing to require refiners to report information on the volume, API gravity, sulfur content, and country of origin of each crude oil batch used as feedstock at a refinery. Finally, we are proposing to require reporting on the volume of diesel fuel that is most likely to be used in the onroad mobile source sector.

The only GHG required to be reported under proposed 40 CFR part 98, subpart MM is CO_2. Combustion of petroleum products may also lead to trace quantities of CH_4 and N_2O emissions.[102] The amounts of CH_4 and N_2O are dependent on factors other than fuel characteristics such as combustion temperatures, air-fuel mixes, and use of pollution control equipment. These other factors vary significantly across and within the major categories of petroleum product end-uses. EPA bases national estimates of CH_4 and N_2O for the U.S. GHG Inventory on bottom-up data, such as penetration of control technologies and distance traveled for on-highway mobile sources.[103] We seek comment on whether or not EPA should use the national inventory estimates of CH_4 and N_2O emissions from petroleum product combustion and apportion them to individual petroleum product suppliers based on the quantity of their product.

Data related to products supplied to or exported from the economy. We are proposing that petroleum product suppliers use a mass-balance method to calculate CO_2 emissions, which is used extensively in national GHG inventories and in existing reporting guidelines for facilities, companies, and states, such as the WRI/WBCSD GHG Protocol.[104] The mass balance approach is based on readily available information: The volume of fuel, which is typically tracked by suppliers, and the carbon content of the fuel, i.e., mass of carbon per volume of fuel (the carbon content of the petroleum product is also referred to as the CO_2 emission factor). The formula to apply this method is simple and can be automated.[105] Carbon content, where not measured directly, can be estimated using other readily available data and literature values.

There is substantial trade and transfer of products between refiners, between importers and refiners, and between other parties. The products supplied by one refiner might in some cases serve as the feedstock for another refiner. To avoid double-counting of emissions, we are proposing an elaboration of the mass-balance approach for use by refiners. Under this elaborated approach, to account for the fact that any non-crude feedstock[106] entering a refiner's facility would have already been reported by the non-crude feedstock's source (such as an importer or another refiner), the refiner would measure and report the potential CO_2 emissions from the non-crude feedstock, but then subtract the amount from the overall CO_2 emissions they report.

We are proposing that suppliers report to EPA the types of products and quantities of products sold during the reporting period or otherwise transferred to another facility, in the case of refiners, or corporate entity, in the case of importers and exporters. This information underlies the proposed CO_2 emissions calculations. By focusing on petroleum products sold versus produced, we would avoid double-counting products, especially semi-refined products, that would either be used onsite by the facility to generate energy or that would be reused as a feedstock at some point in the facility's production process.

We are not proposing that petroleum product suppliers collect new information on those petroleum products which may be used or converted by other entities into long-lived products that are not oxidized or combusted, or oxidized slowly over long periods of time (e.g., plastics). A comprehensive and rigorous system for tracking the fate of non-energy petroleum products and their various end-uses is beyond the scope of this rule, and would require a much more burdensome reporting obligation for petroleum product suppliers. However, at some point, we may need to address the question of non-emissive end uses of petroleum products as part of future climate policy development. We request comment on our proposal to require petroleum product suppliers to report the CO_2 emissions associated with products that could potentially have non-emissive end-uses. We also request comment on ways in which non-emissive end-uses could be tracked and reported.

Data related to crude feedstocks. We are proposing that refiners report basic information to EPA on the crude oil feedstock type, API gravity, sulfur content and country of origin during the reporting period. This basic information on the feedstock characteristics would provide useful information to EPA to assess the lifecycle GHG emissions associated with petroleum refining.

Data related to non-crude petroleum and natural gas feedstocks. As discussed previously, in order to minimize double-counting of non-crude petroleum products and NGLs, we would require refiners to report the volume and CO_2 emissions of any non-crude petroleum and natural gas feedstock that was acquired from an outside facility. We are not proposing to require reporting of products produced at the facility and recycled back into processing. In the event that a reporter cannot determine whether a feedstock is petroleum-or natural gas-based, we are proposing to have the reporter assume the product is petroleum-based. We request comment on methods for distinguishing between natural gas- and petroleum-based feedstock.

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[102] CO_2, CH_4 and N_2O emissions from combustion of petroleum products were 1900, 3.1, and 34.1 million metric tons CO_2e, respectively.

[103] 2008 U.S. GHG Inventory, Annex 3—Methodological Descriptions for Additional Source or Sink Categories. pp. A–106 to A–120.

[104] See The Greenhouse Gas Protocol (GHG Protocol) *http://www.ghgprotocol.org/*; the 2008 U.S. Inventory *http://www.epa.gov/climatechange/emissions/downloads/08_Energy.pdf*, and the 2006 IPCC Guidelines *http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html.*

[105] The generic formula is CO_2 = Fuel Quantity * Carbon Content * 44/12.

[106] This could include both petroleum- and natural gas-based products.

Data related to co-processed biomass and blended biomass-based fuels. We are proposing to require reporters to provide information on the biogenic portion of petroleum products under two circumstances discussed below. We are proposing these reporting requirements to ensure that EPA can distinguish between potential emissions of carbon from biogenic sources (i.e., biomass) and from non-biogenic sources (i.e., fossil fuel). We believe it is important to make this distinction because CO_2 emissions from biogenic sources are traditionally accounted for at the time of harvest, collection, or disposal, rather than the point of fuel combustion.

First, we are proposing to require refiners to report information related to biomass that is co-processed with a petroleum feedstock (crude or non-crude) to produce a product that would be supplied to the economy. We propose that refiners report the volume of and estimated CO_2 emissions associated with both the biomass and petroleum-based portions of these products. Refiners would then subtract the estimated CO_2 emissions from the biomass portion from their total CO_2 emissions calculation. We are not proposing to require refiners to report on CO_2 emissions from biomass they combust onsite or co-process with a petroleum feedstock to produce a product that they combust onsite; these emissions are addressed in Section V.Y of this preamble.

Second, in the case where a reporter supplies or exports a petroleum product that is blended with a biomass-based fuel, we are proposing only to require CO_2 emissions information on the petroleum-based portion of the product along with the volume of the biomass-based fuel. This reporting requirement would also apply to a refiner that receives a blended fuel (e.g., gasoline with ethanol) as feedstock to be further refined or otherwise used onsite. We are also assuming that all reporters would know the percent volume of the biomass-based component of any product. We seek comment on this assumption and on any necessary methods for distinguishing between biomass- and petroleum-based components of blended fuels.

Under this proposal, we are proposing to require reporters to calculate and report CO_2 emissions from products derived from co-processing biomass and petroleum feedstocks outside their operations as if the products were entirely petroleum-based. We are not requiring reporters to report information on products that were derived entirely from biomass. We seek comment on this proposed approach towards biomass reporting.

Carbon Content. We are proposing that petroleum product suppliers that directly measure the batch-or facility-specific density or carbon share of their products report the density and carbon content values along with the testing and sampling standards they use for each product.[107] We are not proposing that reporters that choose to use the default carbon content values provided in the proposed 40 CFR part 98, subpart MM be required to report these values since they can easily be back-calculated with data on volume and CO_2 emissions.

Designated End-use. Although not required as a direct input to the mass-balance equation for estimating total emissions, EPA is also interested in collecting data on designated end-use (such as for use in a highway vehicle versus a stationary boiler) of petroleum products for effective policy development. EPA recognizes that petroleum product suppliers do not always have full knowledge of the ultimate end-use of their products. We evaluated the potential end-uses that petroleum product suppliers could know, including end-use designations required by EPA's transportation fuel regulations,[108] and determined that reporters should be able to identify diesel fuel intended for use on highway since it must contain less than 15 ppm of sulfur and should not contain dyes or markers associated with nonroad and stationary fuel. We recognize, however, that some of this fuel may ultimately be used in nonroad and stationary sectors. We request comment on this proposal, on the extent to which this and other refinery gate (ex refinery) and importer end-use designations reflect actual end-use consumption patterns, and other options EPA could pursue to track the combustion-related end-uses of petroleum products.

Reporting to EIA. We realize that most petroleum product suppliers report much of the relevant fuel quantity information to EIA on a monthly, quarterly, or annual basis. During development of this proposal, EPA consulted with EIA on its existing reporting programs and discussed the feasibility of sharing this information through an interagency agreement, rather than requiring reporting parties to report the same information multiple times to the Federal government.

However, we have concluded that comparability and consistency in reporting processes across all facilities included in the entire rule is vital, particularly with respect to timing of submission, reporting formats, QA/QC, database management, missing data procedures, transparency and access to information, and recordkeeping. In addition, all refineries would be reporting emissions from petroleum refining processes under proposed 40 CFR part 98, subpart Y. Finally, as noted above, we are requesting readily available information from petroleum product suppliers and do not consider reporting information to more than one Federal agency an undue burden for these industries. We thus considered but are not proposing an option in which EPA obtains facility-specific data for suppliers of petroleum products through access to existing Federal government reporting databases, such as those maintained by EIA. However, in order to reduce the reporting burden placed on industry, we would consider information that refiners and importers already report to EIA with respect to units and frequency, for example, when crafting the reporting requirements for refiners, importers, and exporters under the final rule.

Reporting to EPA's Office of Transportation of Air Quality. EPA currently collects a variety of information associated with the production and use of most transportation fuels in the U.S. in order to ensure compliance with existing fuel regulations and standards. Over the course of many years, EPA has developed a reporting system for its transportation fuels programs that incorporates a number of compliance and enforcement mechanisms. For example, all reporting parties must register their facilities with EPA and in many cases use EPA's dedicated reporting web portal, the CDX, to submit their reports. We review reports to identify reporting errors (e.g. incorrect report formats or missing data) but also require reporting parties to self-report any errors or anomalies in their data. For some of our existing transportation fuels reporting programs, we employ the use of annual attest engagements, audits of the reporting parties' records by an independent certified public accountant or certified internal auditor, to help ensure that the data submitted in reports to EPA reflect data maintained in the reporting parties' records.

For purposes of this rule, we are interested in minimizing the additional reporting burden on reporters by

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[107] Proposed 40 CFR part 98, subpart MM identifies the specific ASTM standards that reporters must use, but allows discretion for the reporter to select the most appropriate standard.

[108] Current regulations require refiners and importers to designate diesel fuel (40 CFR 80.598(a)(2)).

utilizing existing reporting and verification systems, such as EPA's transportation fuel programs reporting protocols, as appropriate. We request comments on ways to take advantage of existing reporting and verification programs, particularly those related to transportation fuels. Specifically, as noted in Section IV.J.3 of this preamble, we are seeking comment on requiring annual attest engagements for all reporters under proposed 40 CFR part 98, subpart MM. In addition, whereas the proposed deadline for annual report submission is March 31 following the reporting year for all reporters under this rule, we seek comment on an alternative deadline of February 28 following the reporting year for annual reports from suppliers of petroleum products. This deadline would align with the submission deadline for annual compliance reports under several existing EPA fuels programs.

6. Selection of Records That Must Be Retained

We are proposing that reporters under this source category must maintain all of the following records: copies of all reports submitted to EPA under this rule, records documenting the type and quantity of petroleum products and NGLs supplied to or exported from the economy, records documenting the type, characteristics, and quantity of purchased feedstocks, including crude oil, LPGs, biomass, and semi-refined feedstocks, records documenting the CO_2 emissions that would result from complete combustion or oxidation of the petroleum products, NGLs, and biomass, and sampling and analysis records related to all batch-or facility-specific carbon contents developed and used in reporting to EPA.

These records should contain data directly used to calculate the emissions that are reported and are necessary to enable verification that the CO_2 emissions monitoring and calculations were done correctly. These records would also consist of information used to determine the required characteristics of crude feedstocks.

NN. Suppliers of Natural Gas and Natural Gas Liquids

1. Definition of the Source Category

This subpart would require reporting by facilities and companies that introduce or supply natural gas and NGLs into the economy (e.g., LDCs). These facilities and companies would report the CO_2 emissions that would result from complete combustion or oxidation of the quantities of natural gas and NGLs supplied (e.g., as a fuel).

Combustion and other uses of natural gas are addressed in other subparts, such as proposed 40 CFR part 98, subpart C (General Fuel Stationary Combustion Sources).

Natural gas is a combustible gaseous mixture of hydrocarbons, mostly CH_4. It is produced from wells drilled into underground reservoirs of porous rock. Natural gas withdrawn from the well may contain liquid hydrocarbons and nonhydrocarbon gases. The natural gas separated from these components at gas processing plants is considered ''dry''. Dry natural gas is also known as consumer-grade natural gas. In 2006, the combustion of natural gas for useful heat and work resulted in 1,155.1 million metric tons CO_2e emissions out of a total of 7,054.2 million metric tons CO_2e of GHG emissions in the U.S.

In addition to being combusted for energy, natural gas is also consumed for non-energy uses in the U.S. The non-energy applications of natural gas are diverse, and include feedstocks for petrochemical production, ammonia, and other products. In 2006, emissions from non-energy uses of natural gas were 138 million metric tons CO_2e.

The supply chain for delivering natural gas to consumers is complex, involving producers (i.e., wells), processing plants, storage facilities, transmission pipelines, LNG terminals, and local distribution companies. In developing the proposed rule, we concluded that inclusion of all natural gas suppliers as reporters would not be practical from an administrative perspective, nor would it be necessary for complete coverage of the supply of natural gas. In determining the most appropriate point in the supply chain of natural gas, we applied the following criteria: An administratively manageable number of reporting facilities; complete coverage of natural gas supply as a group of facilities or in combination with facilities reporting under other subparts of this rule; minimal irreconcilable double-counting of natural gas supply; and feasibility of monitoring or calculation methods.

Based on these criteria, we are proposing to include LDCs for deliveries of dry gas, and natural gas processing facilities for the supply of NGLs as reporters under this source category. LDCs receive natural gas from the large transmission pipelines and re-deliver the gas to end users on their systems, or, in some cases, re-deliver the natural gas to other LDCs or even other transmission pipelines. Importantly, LDCs keep records on the amount of natural gas delivered to their customers. In 2006, LDCs delivered about 12.0 trillion cf or 60 percent of the total 19.9 trillion cf delivered to consumers. The balance of the natural gas is delivered directly to large end users in industry and for power generation. Most of these large end users would already be included as reporting facilities for direct GHG emissions because their emissions exceed the respective emissions threshold for their source category.

LDCs meter the amount of gas they receive and meter and bill for the deliveries they make to all end-use customers or other LDCs and pipelines. Some of the end-use customers may be large industrial or electricity generating facilities that would be included under other subparts for direct emissions related to stationary combustion. LDCs already report their total deliveries to DOE as well as to State regulators. There are approximately 1,207 LDCs in the U.S.[109]

Natural gas processing facilities (defined as any facility that extracts or recovers NGLs from natural gas, separates individual components of NGLs using fractionation, or converts one form of natural gas liquid into another form such as butane to isobutene using isomerization process) take raw untreated natural gas from domestic production and strip out the NGLs, and other compounds. The NGLs are then sold, and the processed gas is delivered to transmission pipelines.[110] According to EIA, processors generated about 638 million barrels of NGLs, in 2006, which is 69 percent of NGLs supplied in the U.S. Processors meter the NGLs they produce and deliver to pipelines. These data are reported to DOE.

We are not proposing that processing plants report supply of dry natural gas to transmission pipelines. While the processing industry in 2006 delivered an estimated 13.8 trillion cf of processed, pipeline quality gas into the pipeline system, an estimated 30 percent of dry natural gas goes directly from production fields to the transmission pipelines, completely by-passing processing plants. In the interest of increasing coverage, we considered but decided not to propose including

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[109] This number includes all LDCs that report to EIA on Form 176, and includes separate operating companies owned by a single larger company, as for example Niagara Mohawk, a LDC in New York, owned by National Grid, which also owns other LDCs in New York and New England. For the purposes of this rule, LDCs are defined as those companies that distribute natural gas to ultimate end users and which are regulated as separate entities by state public utility commissions.

[110] This definition of processors does not include field gathering and boosting stations, and is therefore narrower in scope than the definition provided earlier in the preamble for the oil and gas sector.

production wells producing pipeline quality natural gas (i.e., not needing significant processing) due to the large number of potential facilities affected.

We considered but are not proposing to include the approximately 448,641 (in 2006) production wells in the U.S. as covered facilities. Producers routinely monitor production to predict sales, to distribute sales revenues to working interest owners, pay royalties, and pay State severance taxes. These data are reported regularly to State agencies. At the national level, however, inclusion of producers would be administratively difficult and would include many small facilities. EIA collects reports from a subset of larger producers in key States, but relies on State data to develop comprehensive aggregated national statistics.

We considered but are not proposing to include interstate and intrastate pipelines. Pipeline operators transport almost all of the natural gas consumed in the U.S. including both domestically produced and imported natural gas. While there are a relatively modest number of transmission pipelines, approximately 160, and the operators meter flows and report these data to DOE, their inclusion as reporters would introduce significant complications. The U.S. pipeline network is characterized by interconnectivity, in which natural gas moves through multiple pipelines on its way to the consumers. Given the hundreds of receipt and delivery points and the interconnections with a multiplicity of other pipelines, processing plants, LDCs, and end users, a substantial amount of double-counting errors would be introduced. A time- and resource-intensive administrative effort by EPA and reporting companies would be required annually in an attempt to correct this double-counting.

We are also not proposing to include importers of natural gas as reporting facilities. Natural gas is imported by land via transmission pipelines (primarily from Canada), and as LNG via a small number of port terminals (predominantly on the East and Gulf coasts). Imported natural gas ultimately is delivered to consumers by LDCs or sent directly to high volume consumers who would report under other subparts of proposed 40 CFR part 98.

EPA requests comment on the inclusion of LDCs and processing plants, and the exclusion of other parts of the natural gas supply and distribution chain. For additional background information on suppliers of natural gas, please refer to the Suppliers of Natural Gas and NGLs TSD (EPA–HQ–OAR–2008–0508–040).

2. Selection of Reporting Threshold

In developing the reporting threshold for LDCs and natural gas processors, EPA considered emissions-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 per year. For natural gas suppliers, these thresholds are applied on the amount of CO_2 emissions that would result from complete combustion or oxidation of the natural gas. These thresholds translate into 18,281 thousand cf, 182,812 thousand cf, 457,030 thousand cf, and 1,828,120 thousand cf of natural gas, respectively.

Table NN–1 of this preamble illustrates the LDC emissions and facilities that would be covered under these various thresholds.

Table NN–1. Threshold Analysis for LDCs

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	632,100,851	1,207	632,004,022	99.98	1,022	85
10,000	632,100,851	1,207	630,106,725	99.68	521	43
25,000	632,100,851	1,207	627,543,971	99.28	365	30
100,000	632,100,851	1,207	619,456,607	98.00	206	17

We propose to include all LDCs as reporters in this source category. Of the approximate 1,207 LDCs, the 25,000 metric tons CO_2e threshold would capture the 365 largest LDCs and 98 percent of the natural gas that flows through them. The remaining LDCs already report annual throughput to EIA in form EIA 176. Thus, inclusion of all LDC's does not require collection of new information. Comments on this conclusion are requested.

Table NN–2 of this preamble illustrates the NGL emissions and number of processing facilities that would be covered under these various thresholds.

Table NN–2. Threshold Analysis for NGLs From Processing Plants

Threshold level metric tons CO_2e/yr	Total national emissions metric tons CO_2e/yr	Total number of facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	164,712,077	566	164,704,346	100	466	82
10,000	164,712,077	566	164,404,207	100	400	71
25,000	164,712,077	566	163,516,733	99	347	61
100,000	164,712,077	566	157,341,629	96	244	43

We propose there be no reporting threshold for natural gas processing plants. Each natural gas processing plant is already required to report the supply (beginning stocks, receipts, and production) and disposition (input, shipments, fuel use and losses, and ending stocks) of NGLs monthly on EIA Form 816. Processing plants are also required to report the amounts of natural gas processed, NGLs produced, shrinkage of the natural gas from NGLs extraction, and the amount of natural gas used in processing on an annual basis on EIA Form 64A.

For a full discussion of the threshold analysis, please refer to the Suppliers of Natural Gas and NGLs TSD (EPA–HQ–

OAR–2008–0508–040). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

Under this subpart, we are proposing reporting the amount of natural gas and NGLs produced or supplied to the economy annually, as well as the CO_2 emissions that would result from complete oxidation or combustion of this quantity of natural gas and NGLs.

The only GHG required to be reported under this subpart is CO_2. Combustion of natural gas and NGLs may also lead to trace quantities of CH_4 and N_2O emission.[111] Because the quantity of CH_4 and N_2O emissions are small, highly variable and dependent on technology and operating conditions in which the fuel is being consumed (unlike CO_2), we are not proposing that natural gas suppliers report on these emissions. We seek comment on whether or not EPA should use the national inventory estimates of CH_4 and N_2O emissions from natural gas combustion, and apportion them to individual natural gas suppliers based on the quantity of their product. We request comments on this conclusion.

We are proposing that LDCs and natural gas processing plants use a mass-balance method to calculate CO_2 emissions. The mass balance approach is based on readily available information: The quantity of fuel (e.g., thousand cf, barrels, mmBtus), and the carbon content of the fuel. The formula is simple and can be automated. The mass-balance approach is used extensively in national GHG inventories, and in existing reporting guidelines for facilities, companies, and States, such as the WRI/WBCSD GHG Protocol.

For carbon content, we have prepared two look-up tables listing default CO_2 emission factors of natural gas and natural gas liquid. These emission factors are drawn from published sources, including the American Petroleum Institute Compendium, EIA, and the U.S. GHG Inventory.

Where natural gas processing plants extract and separate individual components of NGLs, the facilities should report carbon content by individual component of the NGLs. In cases where raw NGLs are not separated, the processing plants should report carbon content for the raw NGLs. LDCs and natural gas processing plants can substitute their own values for carbon content provided they are developed according to nationally-accepted ASTM standards for sampling and analysis.

We considered but do not propose an option in which LDCs and natural gas processing plants would be required to sample and analyze natural gas and NGLs periodically to determine the carbon content. Given the close correlation between carbon content and BTU value of natural gas and NGLs, and the availability of BTU information on these products, EPA believes that periodic sampling and analysis would impose a cost on facilities but would not result in improved accuracy of reported emissions values. We request comment on an approach in which natural gas suppliers would be required to develop facility- and batch-specific carbon contents through periodic sampling and analysis. The various approaches to monitoring GHG emissions are elaborated in the Suppliers of Natural Gas and NGLs TSD (EPA–HQ–OAR–2008–0508–040).

4. Selection of Procedures for Estimating Missing Data

EPA has determined that the information to be reported by LDCs and gas processing plants is routinely collected by facilities as part of standard operating practices, and expects that any missing data would be negligible. Typically, natural gas amounts are metered directly at multiple stages, and billing systems require rigorous reconciliation of data. In cases where metered data are not available, reporters may estimate the missing volumes based on contracted maximum daily quantities and known conditions of receipt and delivery during the period when data are missing.

5. Selection of Data Reporting Requirements

We propose that LDCs and gas processing plants report CO_2 emissions directly to EPA on an annual basis. LDCs would also report CO_2 emissions disaggregated into categories that represent residential consumers, commercial consumers, industrial consumers, and electricity generating facilities. Further information would be provided on the facilities to which LDCs deliver greater than 460,000 thousand cf of natural gas during the calendar year, which would be used by EPA to check and verify information on facilities covered under other subparts of this rule because of their onsite stationary combustion or process emissions.[112]

Natural gas processing plants would report CO_2 emissions disaggregated by individual components of NGLs extracted and separated, where applicable. Where raw NGLs are not separated into individual components, plants should report CO_2 emissions for raw NGLs.

We considered but are not proposing an option in which EPA obtained facility-specific data for natural gas and NGLs through access to existing Federal government reporting databases, such as those maintained by EIA. We have concluded that comparability and consistency in reporting processes across all facilities included in the entire rule is vital, particularly with respect to timing of submission, reporting formats, QA/QC, database management, missing data procedures, transparency and access to information, and recordkeeping. In addition, large natural gas processing plants would already be included as reporting facilities under proposed 40 CFR 98.2(a)(2), therefore there is minimal burden in reporting the additional information proposed under this subpart. Finally, as noted above, we are requesting readily available information from LDCs and natural gas processing facilities, and do not consider reporting information to more than one Federal agency to place an undue burden on these industries.

6. Selection of Records That Must Be Retained

Records that must be kept include quantity of individual fuels supplied, BTU content, carbon content determined, flow records and/or invoice records for customers with amount of natural gas received, type of customer receiving natural gas (so the disaggregated report by category can be checked), and data for determining carbon content for natural gas processing plants. These records are necessary to enable verification that the GHG monitoring and calculations were done correctly. Records related to the end-user (e.g., ammonia facility) are required to allow us to reconcile data reported by different facilities and entities, and to ensure that coverage of natural gas supply and end-use is comprehensive.

A full list of records that must be retained onsite is included in proposed 40 CFR part 98, subparts A and NN.

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[111] In 2006, CO_2, CH_4 and N_2O emissions from natural gas combustion were 1,155.1, 1.0, and 0.6 $MMTCO_2e$, respectively.

[112] 460,000 thousand cf/year is a conservative estimate of the amount of dry natural gas that when fully combusted would produce at least 25,000 metric tons of CO_2.

OO. Suppliers of Industrial GHGs

1. Definition of the Source Category

The industrial gas supply category includes facilities that produce N_2O or fluorinated GHGs,[113] importers of N_2O or fluorinated GHGs, and exporters of N_2O or fluorinated GHGs. These facilities and entities are collectively referred to as ''suppliers of industrial GHGs''.

Under the proposed40 CFR part 98, subpart OO, if you produce fluorinated GHGs or N_2O, you would be required to report the quantities of these gases that you produce, transform (use as feedstocks in the production of other chemicals), destroy, or send to another facility for transformation or destruction. Importers and exporters of bulk fluorinated GHGs and N_2O would be required to report the quantities that they imported or exported and the quantities that they imported and sold or transferred to another person for transformation or destruction. As described in Sections III and IV of this preamble, emissions from general stationary fuel combustion sources and fugitive emissions from fluorinated gas production are addressed separately (Sections V.C and V.L of this preamble).

Fluorinated GHGs. Fluorinated GHGs are man-made gases used in a wide variety of applications. They include HFCs, PFCs, SF_6, NF_3, fluorinated ethers, and other compounds such as perfluoropolyethers. CFCs and HCFCs also contain fluorine and are GHGs, but both the production and consumption (production plus import minus export) of these ODS are currently being phased out and otherwise regulated under the Montreal Protocol and Title VI of the CAA. We are not proposing requirements for ODS under proposed 40 CFR part 98.

Fluorinated GHGs are powerful GHGs whose ability to trap heat in the atmosphere is often thousands to tens of thousands times as great as that of CO_2, on a pound-for-pound basis. Some fluorinated GHGs are also very long lived; SF_6 and PFCs have lifetimes ranging from 3,200 to 50,000 years.[114]

HFCs are the most commonly used fluorinated GHGs, they are used primarily as a replacement for ODS in a number of applications, including air-conditioning and refrigeration, foams, fire protection, solvents, and aerosols. PFCs are used in fire fighting and to manufacture semiconductors and other electronics. SF_6 is used in a diverse array of applications, including electrical transmission and distribution equipment (as an electrical insulator and arc quencher) and in magnesium casting operations (as a cover gas to prevent oxidation of molten metal). NF_3 is used in the semiconductor industry, increasingly to reduce overall semiconductor GHG emissions through processes such as NF_3 remote cleaning and NF_3 substitution during in-situ cleaning. Fluorinated ethers (HFEs and HCFEs) are used as anesthetics (e.g., isofluorane, desflurane, and sevoflurane) and as heat transfer fluids (e.g., the H-Galdens).

In 2006, 12 U.S. facilities produced over 350 million metric tons CO_2e of HFCs, PFCs, SF_6, and NF_3. More specifically, 2006 production of HFCs is estimated to have exceeded 250 million metric tons CO_2e while production of PFCs, SF_6, and NF_3 was estimated to be almost 100 million metric tons CO_2e. We estimate that an additional 6 facilities produced approximately 1 million metric tons CO_2e of fluorinated anesthetics.

Fluorinated GHGs are imported both in bulk (contained in shipping containers and cylinders) and in products. For further information, see the Bulk Imports and Exports of Fluorinated Gases TSD (EPA–HQ–OAR–2008–0508–042) and the Imports of Fluorinated GHGs in Products TSD (EPA–HQ–OAR–2008–0508–043). EPA estimates that over 110 million metric tons CO_2e of bulk HFCs, PFCs, and SF_6 were imported into the U.S. in 2007 by over 100 importers (PIERS, 2007). In CO_2e terms, SF_6 and NF_3 each made up about one third of this total, while HFCs accounted for one quarter and PFCs made up the remainder. Several other fluorinated GHGs may be imported in smaller quantities, including fluorinated ethers such as the H-Galdens and anesthetics such as desflurane (HFE–236ea2), isoflurane (HCFE–235da2), and sevoflurane.

A variety of products containing fluorinated GHGs are imported into the U.S. Imports of particular importance include pre-charged air-conditioning, refrigeration, and electrical equipment and closed-cell foams. Pre-charged air-conditioning and refrigeration equipment contains a full or partial (holding) charge of HFC refrigerant, while pre-charged electrical equipment contains a full or partial charge of SF_6 insulating gas. Closed-cell foams contain HFC blowing agent.

We estimate that in 2010, approximately 18 million metric tons CO_2e of fluorinated GHGs would be imported in pre-charged equipment.[115] In 2006, an additional 2.5 million metric tons CO_2e of fluorinated GHGs were imported in closed-cell foams. Together, these imports are expected to constitute between five and ten percent of U.S. consumption of fluorinated GHGs.

Once produced or imported, fluorinated GHGs can have hundreds of millions of downstream emission points. For example, the gases are used in almost all car air conditioners and household refrigerators and in other ubiquitous products and applications. Thus, tracking emissions of these gases from all downstream uses would not be practical.

Nitrous oxide. N_2O is a clear, colorless, oxidizing gas with a slightly sweet odor. N_2O is a strong GHG with a GWP of 310.[116]

N_2O is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia and as an anesthetic in various dental and veterinary applications. In this application, it is used to treat short-term pain, for sedation in minor elective surgeries and as an induction anesthetic. The second main use of N_2O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. In smaller quantities, N_2O is also used as an oxidizing agent and etchant in semiconductor manufacturing, an oxidizing agent (with acetylene) in atomic absorption spectrometry, an oxidizing agent in blowtorches used by jewelers and others, a fuel oxidant in auto racing, and a component of the production of sodium azide, which is used to inflate airbags.

Two companies operate a total of five N_2O production facilities in the U.S.. These facilities produced an estimated 4.5 million metric tons CO_2e of N_2O in 2006.

N_2O may be imported in bulk or inside products. We estimate that approximately 300,000 metric tons CO_2e of bulk N_2O were imported into the U.S. in 2007 by 18 importers. Products that may be imported include several of those listed above, particularly pre-blended anesthetics and aerosol

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[113] Please see the proposed definition of fluorinated GHG near the end of this section.

[114] IPCCC SAR available at: *http://www.ipcc.ch/ipccreports/assessments-reports.htm.*

[115] The number of refrigeration and AC units imported in 2010 was assumed to equal the number of units imported in 2006. The refrigeration and AC units imported in 2006 were pre-charged with both HFCs and HCFCs. (HCFCs are ozone-depleting substances that are regulated under the Montreal Protocol and are exempt from the proposed definition of fluorinated GHG.) However, by 2010, EPA expects that all imported refrigeration and AC units will be charged with HFCs, because imports pre-charged with HCFCs will not be permitted starting in that year.

[116] IPCCC SAR.

products such as pressure-packaged whipped cream.

Further information on N_2O supply and import can be found in the Suppliers of Industrial GHGs TSD (EPA–HQ–OAR–2008–0508–041).

Selection of Reporting Facilities and Types of Data to be Reported. Because fluorinated GHGs and N_2O have an extremely large number of relatively small downstream sources, reporting of downstream emissions of these gases would be incomplete, impractical, or both. On the other hand, the number of upstream producers, importers, and exporters is comparatively small, and the quantities that would be reported by individual gas suppliers are often quite large. Thus, upstream reporting is likely to be far more complete and cost-effective than downstream reporting. For these reasons, we are proposing to require upstream reporting of the quantities required to estimate U.S. consumption of N_2O and fluorinated gases. ''Consumption'' is defined as the sum of the quantities of chemical produced in or imported into the U.S. minus the sum of the quantities of chemical transformed (used as a feedstock in the production of other chemicals), destroyed, or exported from the U.S.

In developing this proposed rule, we reviewed a number of protocols that track chemical consumption, its components (production, import, export, etc.), or similar quantities. These protocols included EPA's Stratospheric Ozone Protection regulations at 40 CFR part 82, the EU Regulation on Certain Fluorinated Greenhouse Gases (No. 842/2006), the Australian Commonwealth Government Ozone Protection and Synthetic Greenhouse Gas Reporting Program, EPA's Chemical Substances Inventory Update Rule at 40 CFR 710.43, EPA's Acid Rain regulations at 40 CFR part 75, the TRI Program, and the 2006 IPCC Guidelines.[117]

We reviewed these protocols both for their overall scope and for their specific requirements for monitoring and reporting. The monitoring requirements are discussed in Section V.OO.3 of this preamble. The protocols whose scopes were most similar to the one proposed for industrial gas supply were EPA's Stratospheric Protection Program, the EU Regulation on Certain Fluorinated Greenhouse Gases, the Australian Synthetic Greenhouse Gas Reporting Program, and EPA's Chemical Substances Inventory Update Rule. All four of these programs require reporting of production and imports, and the first three also require reporting of exports. In addition, the EU regulation and EPA's Stratospheric Ozone Protection Program require reporting of the quantities of chemicals (ODS) transformed or destroyed. In general, the proposed requirements in this rule are based closely on those in EPA's Stratospheric Ozone Protection Program. By accounting for all chemical flows into and out of the U.S., including destruction and transformation, this approach results in an estimate of consumption that is more closely related to actual U.S. emissions than are estimates of consumption that do not account for all of these flows.

Proposed Definition of Fluorinated GHGs. We propose to define ''Fluorinated GHG'' as SF_6, NF_3, and any fluorocarbon except for ODS as they are defined under EPA's stratospheric protection regulations at 40 CFR part 82, subpart A. In addition to SF_6 and NF_3, this definition would include any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

EPA is proposing this definition because HFCs, PFCs, SF_6, NF_3, and many fluorinated ethers are known to have significant GWPs. (For a list of these GWPs, see Table A–1 of proposed 40 CFR part 98, subpart A.) In addition, although not all fluorocarbons have had their GWPs evaluated, any fluorocarbon with an atmospheric lifetime greater than one year is likely to have a significant GWP due to the radiative properties of the carbon-fluorine bond.

As discussed above, ODS are excluded from the proposed definition of fluorinated GHG because they are already regulated under the Montreal Protocol and Title VI of the CAA.

EPA requests comment on the proposed definition. EPA also requests comment on two other options for defining or refining the set of fluorinated GHGs to be reported. The first option would permit a fluorocarbon to be excluded from reporting if (1) the GWP for the fluorocarbon were not listed in Table A–1 of proposed 40 CFR part 98, subpart A or in any of the IPCC Assessment Reports or World Meteorological Organization (WMO) Scientific Assessments of Ozone Depletion, and (2) the producer or importer of the fluorocarbon could demonstrate, to the satisfaction of the Administrator, that the fluorocarbon had an atmospheric lifetime of less than one year and a 100-year GWP of less than five. In general, we expect that new fluorocarbons would be used in relatively low volumes. For such chemicals, a GWP of five may be a reasonable trigger for reporting.

The second option would be to require reporting only of those fluorinated chemicals listed in Table A–1 of proposed 40 CFR part 98, subpart A. The disadvantage of this approach is that it would exclude any new (or newly important) fluorocarbons whose GWPs have not been evaluated. As discussed above, fluorocarbons in general are likely to have significant GWPs. Given the pace of technological development in this area, production (and emissions) of these gases could become significant before the chemicals were added to the table.

2. Selection of Reporting Threshold

In developing the proposed thresholds for producers and importers of fluorinated GHGs and N_2O, we considered production, capacity, and import/export 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 per year. Table OO–1 of this preamble shows the emissions and facilities that would be covered under the various thresholds for production and bulk imports of N_2O and HFCs, PFCs, SF_6, and NF_3.

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[117] We also reviewed other programs, including the DOE's 1605(b) Program, EPA's Climate Leaders Program, and the European Commission's Article 6 reporting requirements, but we found that these programs did not monitor consumption or its components.

TABLE OO–1. THRESHOLD ANALYSIS FOR INDUSTRIAL GAS SUPPLY

Source category	Emission threshold level (metrics tons CO_2e/yr)	Total national production or import (metric tons CO_2e/yr)	Number of facilities	Production or imports covered		Facilities Covered	
				Metric tons CO_2e/yr	Percent	Number	Percent
HFC, PFC, SF_6, and NF_3 Producers	1,000	350,000,000	12	350,000,000	100	12	100
	10,000	350,000,000	12	350,000,000	100	12	100
	25,000	350,000,000	12	350,000,000	100	12	100
	100,000	350,000,000	12	350,000,000	100	12	100
N_2O Producers	1,000	4,500,000	5	4,500,000	100	5	100
	10,000	4,500,000	5	4,500,000	100	5	100
	25,000	4,500,000	5	4,500,000	100	5	100
	100,000	4,500,000	5	4,500,000	100	5	100
N_2O and Fluorinated GHG Importers (bulk)	1,000	110,024,979	116	110,024,987	100	111	96
	10,000	110,024,979	116	109,921,970	99.9	81	70
	25,000	110,024,979	116	109,580,067	99.6	61	53
	100,000	110,024,979	116	108,703,112	98.8	44	38

Producers. We are proposing to require reporting for all N_2O and fluorinated GHG production facilities. As shown in Table OO–1 of this preamble, all identified N_2O, HFC, PFC, SF_6, and NF_3 production facilities would be covered at all capacity and production-based thresholds considered in this analysis. We do not have facility-specific production capacity information for the six facilities producing fluorinated anesthetics; however, if all these facilities produced the same quantity in CO_2e terms, they too would probably be covered at all capacity and production-based thresholds.

The requirement that all facilities report would simplify the rule and permit facilities to quickly determine whether or not they must report. The one potential drawback of this requirement is that small-scale production facilities (e.g., for research and development) could be inadvertently required to report their production, even though the quantities produced would be small in both absolute and CO_2e terms. We are not currently aware of any small-scale deliberate production of N_2O or fluorinated GHGs, but we request comment on this issue. These research and development facilities could be specifically exempt from reporting. An alternative approach that would address this concern would be to establish a capacity-based threshold of 25,000 metric tons CO_2e, summed across the facility's production capacities for N_2O and each fluorinated GHG. We request comment on these alternative approaches.

Importers and Exporters. We are proposing to require importers and exporters to report their imports and exports if either their total imports or their total exports, in bulk, of all relevant gases, exceed 25,000 metric tons CO_2e. We are proposing this threshold to reduce the compliance burden on small businesses while still including the vast majority of imports and exports. As is true for HFC production, HFC import and export levels are expected to increase significantly during the next several years as HFCs replace ODS, which are being phased out under the Montreal Protocol.

Because it may be relatively easy for importers and exporters to create new corporations in order to divide up their imports and exports and remain below applicable thresholds, we considered setting no threshold for importers and exporters. However, we are not proposing this option because we are concerned that it would be too burdensome to current small-scale importers. We request comment on this approach, specifically the burden on small-scale importers if they were required to report.

Further information on the threshold analysis for industrial gas suppliers can be found in the Suppliers of Industrial GHGs TSD (EPA–HQ–OAR–2008–0508–041). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

a. Production

If you produce N_2O or fluorinated GHGs, we propose that you measure the total mass of N_2O or fluorinated gases produced by chemical, including production that was later transformed or destroyed at the facility, but excluding any used GHG product that was added to the production process (e.g., HFCs returned to the production facility and added to the HFC production process for reclamation). Production would be measured wherever it is traditionally measured, e.g., at the inlet to the day tank or at the shipping dock. The quantities transformed or destroyed would be reported separately; see Sections V.OO.3.c and V.OO.3.d of this preamble. The quantities of used product added to the production process would be measured and subtracted from the total mass of product measured at the end of the process. This would avoid counting used GHG product as new production.

b. Imports and Exports

If you import or export bulk N_2O or fluorinated GHGs, we propose that you report the total quantities of N_2O or fluorinated GHGs that you import or export by chemical. Reports would include quantities imported in mixtures and the name/number of the mixture, if applicable (e.g., HFC–410A). Reporting would occur at the corporate level. You would not be required to report imports or exports of heels (residual quantities inside returned containers) or transshipments (GHGs that originate in a foreign country and that are destined for another foreign country), but you would be required to keep records documenting the nature of these transactions.

We propose to require reporting of imports and exports in metric tons of chemical because that is the unit in which other quantities (production, emissions, etc.) are proposed to be reported under this rule. However, because the preferred unit for Customs reporting is kg rather than tons, EPA requests comment on whether it should require reporting of imports and exports in kg of chemical.

In general, these proposed requirements are consistent with those of other programs that monitor imports and exports of bulk chemical, particularly EPA's Stratospheric Ozone Protection regulations.

Existing programs vary in their treatment of products containing chemicals whose bulk import must be reported. The Australian program requires reporting of all ODS and GHGs imported in pre-charged equipment, including the identity of the refrigerant, the number of pieces of equipment, and the charge size. The Inventory Update Rule requires reporting of chemicals contained in products if the chemical is designed to be released from the product when it is used (e.g., ink from a pen). EPA's Stratospheric Ozone Protection regulations do not currently require reporting of ODS contained in imported equipment or other imported products; however, (1) EPA has prohibited the introduction into interstate commerce, including import, of certain non-essential products typically pre-charged with these chemicals, and (2) EPA is in the process of proposing new regulations to prohibit import of equipment pre-charged with HCFCs.

We are not proposing to require that importers of products containing N_2O or fluorinated GHGs report their imports. In general, we are concerned that it would be difficult for importers to identify and quantify the GHGs contained in these products and that the number of importers would be high. However, it may be easier for importers to identify and quantify the GHGs contained in a few types of products, such as pre-charged equipment and foams. For example, the identities and amounts of fluorinated GHGs contained in equipment are generally well known; this data is typically listed on the nameplate affixed to every unit. Moreover, in aggregate, the quantities of GHGs imported in equipment can be large, for example, over 7 million metric tons CO_2e in imported pre-charged window air-conditioners. We request comment on whether we should require reporting of imports or exports of pre-charged equipment and/or closed-cell foams, including the likely burden and benefits of such reporting.

c. N_2O or Fluorinated GHGs Transformed

Under the proposed rule, if you chemically transform N_2O or fluorinated GHGs, you would be required to estimate the mass of N_2O or fluorinated GHGs transformed. This estimate would be the difference between (1) the quantity of the N_2O or fluorinated GHG fed into the process for which the N_2O or fluorinated GHG was used as a feedstock, and (2) the mass of any unreacted feedstock that was not returned to the process. Measuring the quantity of N_2O or fluorinated GHGs actually fed into the process would account for any losses between the point where total production of the fluorinated GHG is measured and the point where the fluorinated GHG is reacted as a feedstock (transformed). The mass of any unreacted feedstock that was not returned to the process would be ascertained using mass flow measurements and (if necessary) gas chromatography.

d. Destruction

Under the proposed rule, if you produce and destroy fluorinated GHGs, you would be required to estimate the quantity of each fluorinated GHG destroyed. This estimate would be based on (1) the quantity of the fluorinated GHG fed into the destruction device, and (2) the DE of the device. In developing the estimate, you would be required to account for any decreases in the DE of the device that occurred when the device was not operating properly (as defined in State or local permitting requirements and/or destruction device manufacturer specifications). Finally, you would be required to perform annual fluorinated GHG concentration measurements by gas chromatography to confirm that emissions from the destruction device were as low as expected based on the DE of the device. If emissions were found to be higher, then you would have the option of using the DE implied by the most recent measurements or of conducting more extensive measurements of the DE of the device.

These proposed requirements are identical to those proposed for destruction of HFC–23 that is generated as a byproduct during HCFC–22 production. They are also similar to those contained in EPA's Stratospheric Ozone Protection Regulations. Those regulations include detailed requirements for reporting and verifying transformation and destruction of chemicals.

We are proposing requirements for verifying the DE of destruction devices used to destroy fluorinated GHGs because fluorinated GHGs, particularly PFCs and SF_6, are difficult to destroy. In many cases, these chemicals have been selected for their end uses precisely because they are not flammable. For destruction to occur, temperatures must be quite high (over 2,300 °F), fuel must be provided, flow rates of fuels and air (or oxygen) must be kept above certain limits, flow rates of fluorinated GHG must be kept below others, and for some particularly difficult-to-destroy chemicals such as CF_4, pure oxygen must sometimes be fed into the process. If one or more of these process requirements is not met, DEs can drop sharply (in some cases, by an order of magnitude or more), and fluorinated GHGs would simply be exhausted from the device. Both construction deficiencies and operator error can lead to a failure to meet process requirements; thus, both initial testing and periodic monitoring are important for verifying destruction device performance. We request comment on the option of requiring that the annual destruction device emissions measurement be performed using a compound that is at least as difficult to destroy as the most difficult-to-destroy GHG ever fed into the device, e.g., SF_6 or CF_4.

We believe that owners or operators of facilities that destroy fluorinated GHGs are already likely to verify the DEs of their destruction devices. Many facilities destroying fluorinated GHGs are likely to destroy ODS as well. In this case, they are already subject to requirements to verify the DEs of their devices.

We request comment on the extent of potential overlap between the destruction reported under proposed 40 CFR part 98, subpart OO and that reported under proposed 40 CFR part 98, subpart L. To obtain an accurate estimate of the net supply of fluorinated industrial greenhouse gases, fluorinated GHGs that are produced and subsequently destroyed should be subtracted from the total produced or imported. However, if fluorinated GHGs are never included in the mass produced (e.g., because they are removed from the production process with or as byproducts), then including them in the mass destroyed would lead to an underestimate of supply. One possible solution to this problem would be to require facilities producing and destroying fluorinated GHGs to separately estimate and report their destruction of fluorinated GHGs that have been counted as produced in either the current year or previously.

EPA is not proposing to require reporting of N_2O destruction, because EPA is not aware that such destruction occurs. However, EPA requests comment on this.

e. Precision, Accuracy, and Calibration Requirements

The protocols and guidance reviewed by EPA differ in their level of specificity regarding the measurement of production or other flows, particularly regarding their precision and accuracy requirements. Some programs, such as the Stratospheric Ozone Protection regulations, do not specify any accuracy requirements, while other programs specifically define acceptable errors and reference industry standards for calibrating and verifying monitoring equipment. One of the latter is 40 CFR part 75, Appendix D, which establishes requirements for measuring oil and gas flows as a means of estimating SO_2 emissions from their combustion. These requirements include a requirement that the fuel flowmeter accuracy be within 2 percent of the upper range value and a requirement that flowmeters be recalibrated at least once a year.

In today's proposed rule, we are proposing to require facilities to measure the mass of N_2O or fluorinated GHGs produced, transformed, or destroyed using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. In addition, we are proposing to require that weigh scales, flowmeters, and/or other measurement devices be calibrated every year or sooner if an error is suspected based on mass-balance calculations or other information. Facilities could perform the verification and calibration of their scales and flowmeters during routine product line maintenance. Finally, we are proposing that facilities transforming or destroying fluorinated GHGs calibrate gas chromatographs by analyzing, on a monthly basis, certified standards with known GHG concentrations that are in the same range (percent levels) as the process samples.

EPA requests comment on these proposed requirements. EPA specifically requests comment on the proposed frequency of calibration for flowmeters; the Agency understands that some types of flowmeters that are commonly employed in chemical production, such as the Coriolis type, may require less frequent calibration.

We are proposing specific accuracy, precision, and calibration requirements because the high GWPs and large volumes of fluorinated GHGs produced make such requirements worthwhile for this source category. For example, a one percent error at a typical facility producing fluorinated GHGs would equate to 300,000 metric tons CO_2e. The Agency believes that these precision and accuracy requirements (0.2 percent) should not represent a significant burden to chemical producers, who already use and regularly calibrate measurement devices with similar accuracies.

EPA is not proposing precision and accuracy requirements for importers and exporters of bulk chemical; however, EPA requests comment on whether such requirements (e.g., 0.5 to 1 percent) would be appropriate.

4. Selection of Procedures for Estimating Missing Data

a. Production

In the event that any data on the mass produced, fed into the production process (for used material being reclaimed), fed into transformation processes, fed into destruction devices, or sent to another facility for transformation or destruction, is unavailable, we propose that facilities be required to use secondary measurements of these quantities. For example, facilities that ordinarily measure production by metering the flow into the day tank could use the weight of product charged into shipping containers for sale and distribution. We understand that the types of flowmeters and scales used to measure fluorocarbon production (e.g., Coriolis meters) are generally quite reliable, and therefore it should rarely be necessary to rely on secondary production measurements. In general, production facilities rely on accurate monitoring and reporting of production and related quantities.

If concentration measurements were unavailable for some period, we propose that the facility be required to report the average of the concentration measurements from just before and just after the period of missing data.

There is one proposed exception to these requirements: If the facility has reason to believe that either method would result in a significant under- or overestimate of the missing parameter, then the facility would be required to develop an alternative estimate of the parameter and explain why and how it developed that estimate. We would have the option of rejecting this alternative estimate and replacing it with the value developed using the usual missing data method if we did not agree with the rationale or method for the alternative estimate.

We request comment on these methods for estimating missing data. We also request comment on the option of estimating missing production data based on consumption of reactants, assuming complete stoichiometric conversion. This approach could be used in the very unlikely event that neither primary nor secondary direct measures of production were available.

b. Imports and Exports

We do not believe that missing data would be a problem for importers and exporters of GHGs due to their requirement to declare the quantities of GHGs imported or exported for Customs purposes. However, we request comment on this assumption.

5. Selection of Data Reporting Requirements

Under the proposed rule, facilities would be required to submit data, described below, in addition to the production, import, export, feedstock, and destruction data listed above. This data is intended to permit us to check the main estimates submitted. A complete list of data to be reported is included in proposed 40 CFR part 98, subparts A and OO.

a. Production

Facilities producing N_2O or fluorinated GHGs would be required to submit data on the total mass of reactants fed into the production process, the total mass of non-GHG reactants and byproducts permanently removed from the process, and the mass of used product added back into the production process. Facilities would also be required to provide the names and addresses of other facilities to which they sent N_2O or fluorinated GHGs for transformation or destruction. All quantities would be annual totals in metric tons, by chemical.

b. Imports/Exports and Destroyers of Fluorinated GHG

Importers of N_2O or fluorinated GHGs would be required to submit an annual report that summarized their imports, providing the following information for each import: The quantity of GHGs imported by chemical, the date on which the GHGs were imported, the port of entry through which the GHGs passed, the country from which the imported GHGs were imported, and the importer number for the shipment. Importers would also be required to provide the names and addresses of any persons and facilities to which the imported GHGs were sold or transferred for transformation or destruction.

Exporters of N_2O and fluorinated GHGs would be required to submit an annual report that summarized their exports, similar to the report provided by importers. A complete list of data to be reported is included in the proposed rule.

These proposed requirements are very similar to those that apply to importers and exporters of ODS under EPA's Stratospheric Ozone Protection Program. We are proposing them because they would provide us with valuable information for verifying the nature and size of GHG imports and exports.

In addition to annually reporting the mass of fluorinated GHG fed into the destruction device, facilities destroying fluorinated GHGs would be required to submit a one-time report including the following: The destruction unit's DE, the methods used to record volume destroyed and to measure and record DE, and the names of other relevant Federal or State regulations that may apply to destruction process. This one-time report is very similar to that required under EPA's Stratospheric Ozone Protection regulations.

6. Selection of Records That Must Be Retained

EPA is proposing that the following records be retained because they are necessary to verify production, import, export, transformation, and destruction estimates and related quantities and calibrations.

a. Production

Owners or operators of facilities producing N_2O or fluorinated GHGs would be required to keep records of the data used to estimate production, as well as records documenting the initial and periodic calibration of the flowmeters or scales used to measure production.

b. Imports and Exports

Importers of N_2O or fluorinated GHGs would be required to keep the following records substantiating each of the imports that they report: A copy of the bill of lading for the import, the invoice for the import, the U.S. Customs entry form, and dated records documenting the sale or transfer of the imported GHG for transformation or destruction (if applicable).

Every person who imported a container with a heel would be required to keep records of the amount brought into the U.S. and document that the residual amount in each shipment is less than 10 percent of the net mass of the container when full and would: Remain in the container and be included in a future shipment, be recovered and transformed, or be recovered and destroyed.

Exporters of N_2O, or fluorinated GHGs, would be required to keep the following records substantiating each of the exports that they report: A copy of the bill of lading for the export and the invoice for the import.

c. Transformation

Owners or operators of production facilities using N_2O or fluorinated GHGs as feedstocks would be required to keep records documenting: The initial and annual calibration of the flowmeters or scales used to measure the mass of GHG fed into the destruction device and the periodic calibration of gas chromatographs used to analyze the concentration of N_2O fluorinated GHG in the product for which the GHG is used as a feedstock.

d. Destruction

Owners or operators of GHG production facilities that destroy fluorinated GHGs would be required to keep records documenting: The information that they send in the one-time and annual reports, the initial and annual calibration of the flowmeters or scales used to measure the mass of GHG fed into the destruction device, the method for tracking startups, shutdowns, and malfunctions and any GHG emissions during these events, and the periodic calibration of gas chromatographs used to annually analyze the concentration of fluorinated GHG in the destruction device exhaust stream, as well as the representativeness of the conditions under which the measurement took place.

PP. Suppliers of Carbon Dioxide (CO_2)

1. Definition of the Source Category

CO_2 is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, refrigeration, and petroleum production for EOR, which involves injecting a CO_2 stream into injection wells at well fields for the purposes of increasing crude oil production. Possible suppliers of CO_2 include industrial facilities or process units that capture a CO_2 stream, such as those found at electric power plants, natural gas processing plants, cement kilns, iron and steel mills, ammonia manufacturing plants, petroleum refineries, petrochemical plants, hydrogen production plants, and other combustion and industrial process sources. These suppliers can capture and/or compress CO_2 for delivery to a variety of end users as discussed above.

To ensure consistent treatment of CO_2 suppliers and given the large percentage of CO_2 supplied from CO_2 production wells, we have also proposed inclusion of facilities producing CO_2 from CO_2 production wells in the proposal. Importers and exporters of CO_2 are discussed under suppliers of industrial GHGs (see Section V.OO of this preamble) because most of these facilities import or export multiple industrial gases. For a full discussion of this source category, refer to the Suppliers of CO_2 TSD (EPA–HQ–OAR–2008–0508–044).

According to the U.S. GHG Inventory in 2006, the total supply of CO_2 from industrial facilities and CO_2 production wells was approximately 40.6 million metric tons CO_2e. Further research in support of this rulemaking identified three additional facilities capturing a CO_2 stream for sale. Data for two of these facilities suggest an additional 0.5 million metric tons CO_2e captured. Currently, the majority of CO_2 (79 percent) is produced from CO_2 production wells. Approximately 18 percent of CO_2 is produced at natural gas processing facilities and less than 2 percent from ammonia production facilities. Less than 1 percent of CO_2 is captured at other industrial facilities.

Fugitive Emissions from CO_2 Supply. Fugitive CO_2 emissions can occur from the production of CO_2 streams from CO_2 production wells or capture at industrial facilities or process units, as well as during transport of the CO_2, and during or after use of the gas. We propose to exclude the explicit reporting of fugitive CO_2 emissions from CO_2 supply at industrial facilities or process units and CO_2 production wells, as well as from CO_2 pipelines, injection wells and storage sites. Much of the CO_2 that could ultimately be released as a fugitive emission during transportation, injection and storage, would be accounted for in the CO_2 supply calculated using the methods below. Although separate calculation and reporting of fugitive CO_2 emissions are not proposed for inclusion, we believe that obtaining robust data on fugitive CO_2 emissions from the entire carbon capture and storage chain would provide a more complete understanding of the efficacy of carbon capture and storage technologies as an option for mitigating CO_2 emissions.

We seek comment on the decision to exclude the reporting of fugitive CO_2 emissions from the carbon capture and storage chain. We have concluded that there could be merit in requiring the reporting of fugitive emissions from geologic sequestration of CO_2, in particular. This is discussed further below.

Geologic Sequestration of CO_2. CO_2 used in most industrial applications would eventually be released to the atmosphere. For EOR applications, however, some amount of CO_2 could ultimately remain sequestered in deep geologic formations. The objective of EOR operations is not to maximize reservoir CO_2 retention rates, but to maximize oil production and the amount of CO_2 trapped underground would be a function of site specific and operational factors. There are several EOR operations in the Permian Basin of Texas. One study showed that retention rates for eight reservoirs ranged from 38 to 100 percent with an average of 71 percent, but many of these projects are not mature enough to predict final retention (see Suppliers of CO_2 TSD (EPA–HQ–OAR–2008–0508–044)).

We are not proposing the inclusion of geologic sequestration in the proposed rulemaking. However, the Agency recognizes that there may be significant stakeholder interest in reporting the amount of CO_2 injected and geologically sequestered at EOR operations in order to demonstrate the effectiveness of EOR projects that ultimately intend to store the CO_2 for long periods of time. If an EOR project intends to sequester CO_2 for long periods of time, there would be additional operational factors and post-operational considerations and monitoring. Although EPA is not proposing inclusion of this source in the rulemaking, we have outlined initial thoughts about how geologic sequestration might be included in a reporting program for EOR sequestration or other types of geologic sequestration. We welcome comment on the approach outlined below or other suggestions for how to quantify and verify the amount of CO_2 sequestered in geologic formations.

We reviewed a number of existing and proposed methodologies for monitoring and reporting fugitive emissions from carbon capture, transport, injection and storage. A summary of these protocols can be found in the Review of Existing Programs memorandum (EPA–HQ–OAR–2008–0508–054). Based on this review, a possible approach to include geologic sequestration might be to ask EOR operators to submit a geologic sequestration report. This report could provide information on the amount of CO_2 sequestered (based on the amount of CO_2 injected minus any fugitive emissions) along with a written description of the activities undertaken to document and verify the amount sequestered at each site. This report could include the following supporting information:

- The owner and operator of the geologic sequestration site(s). Including the business name, address, contact name, and telephone number.
- Location of the geologic sequestration site(s) including a map showing the modeled aerial extent of the CO_2 plume over the lifetime of the project.
- Permitting information. Including information on the UIC well permit(s) issued by the appropriate State or Federal agency: Permit number or other unique identification, date the permit was issued and modified if applicable, permitting agency, contact name, and telephone number.
- An overview of the site characteristics, referencing or providing information which demonstrates sufficient storage capacity for the expected operating lifetime of the plant and the presence of an effective confining system overlying the injection zone.
- An assessment of the risks of CO_2 leakage, or escape of CO_2 from the subsurface to the atmosphere, including an evaluation of potential leakage pathways such as deep wells, faults, and fractures.
- An overview of the methods used to model the subsurface behavior of CO_2 and the results.
- Baseline conditions used to evaluate performance of the site including the amount of naturally occurring CO_2 emissions and/or other characteristics that would be used to demonstrate the effectiveness of the system to contain CO_2.
- Summary of the monitoring plan that would be used to determine CO_2 emissions from the site including a discussion of the methodology, rationale, and frequency of monitoring.

The information listed above could be submitted one time and then updated as appropriate. However, the volume of CO_2 injected and any emissions from the storage site, including physical leakage from the geologic formation (via natural features or wells) and/or fugitive emissions of CO_2 co-produced with oil/gas, would be reported on an annual basis in order to quantify the amount of CO_2 geologically sequestered.

2. Selection of Reporting Threshold

EPA has identified at least nine industrial facilities or process units in the U.S. that currently capture CO_2 (three natural gas processing plants, two ammonia facilities, two electricity generation facilities, one soda ash production plant, and one coal gasification facility) (Table PP–1 of this preamble).

TABLE PP–1. THRESHOLD ANALYSIS FOR CO_2 SUPPLY FROM INDUSTRIAL FACILITIES OR PROCESS UNITS

Threshold level metric tons CO_2e	Total national emissions (metric tons CO_2e)	Total number of U.S. facilities	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	8,184,875	9	8,186,881	100	9	100
10,000	8,184,875	9	8,186,881	100	9	100
25,000	8,184,875	9	8,186,881	100	9	100
100,000	8,184,875	9	8,036,472	98	5	56

Under the proposed rule, all industrial facilities that capture and transfer a CO_2 stream would be required to report the mass of CO_2 captured and/or transferred. All known existing facilities exceed all but the highest reporting threshold of 100,000 metric tons CO_2e, taking into account solely the mass of CO_2 captured. At the 25,000 metric tons CO_2e threshold considered by other subparts of this rule, all industrial facilities and capture sites exceed the threshold. The analysis did not account for stationary combustion at each facility. We concluded that all facilities capturing CO_2 would likely already exceed the reporting thresholds under other subparts of proposed 40 CFR part 98 for their downstream emissions. Therefore, a proposed threshold of ‘‘All In’’ for reporting CO_2 supply from industrial facilities or process units would not bring in additional facilities not already triggering other subparts of the proposed rule.

Based on the volumes of CO_2 supplied by facilities producing a CO_2 stream from CO_2 production wells, we also propose that they be subject to reporting. Currently there are four natural formations—Jackson Dome, Bravo Dome, Sheep Mountain, and McElmo Dome. Data are not available to estimate emissions from individual owners or operators operating within the Domes, therefore emissions data are presented at the Dome level (Table PP–2 of this preamble). We propose that all CO_2 production wells owned by a single owner or operator in a given Dome report the mass of CO_2 extracted and/or transferred off site. We are seeking comment on alternative methods for defining the reporting facility (e.g., reporting at the level of an individual well).

TABLE PP–2. THRESHOLD ANALYSIS FOR CO_2 SUPPLY CO_2 PRODUCTION WELLS

Threshold level metric tons CO_2e	Total national emissions (metric tons CO_2e)	Total number of U.S. facilities*	Emissions covered		Facilities covered	
			Metric tons CO_2e/yr	Percent	Number	Percent
1,000	31,358,853	4	31,358,853	100	4	100
10,000	31,358,853	4	31,358,853	100	4	100
25,000	31,358,853	4	31,358,853	100	4	100
100,000	31,358,853	4	31,358,853	100	4	100

*Under this proposal, owners or operator would be required to report on all CO_2 production wells under their ownership/operation in a single Dome.

We have concluded that reporting the volume of the CO_2 streams from CO_2 production wells is important given the large fraction of CO_2 supplied from CO_2 production wells. Further, we conclude that there is minimal burden associated with these requirements, as all necessary monitoring equipment should already be installed to support current operating practice.

Importers and exporters of CO_2 in bulk should review the threshold language for industrial GHG suppliers found in Section OO of this preamble, which proposes a threshold of 25,000 metric tons CO_2e, for applicability. We decided to have a single threshold applicable for bulk importers and exporters of all industrial gases, because many are importing and/or exporting multiple industrial gases. We decided not to include CO_2 imported or exported in products (e.g., fire extinguishers), because of the potentially large number of sources.

For additional information on the threshold analysis please refer to the Suppliers of CO_2 TSD (EPA–HQ–OAR–2008–0508–044). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the RIA and the RIA cost appendix.

3. Selection of Proposed Monitoring Methods

The monitoring plan for CO_2 suppliers at industrial facilities or process units, CO_2 production wells, and CO_2 importers and exporters involves accounting for the total volume of the CO_2 stream captured, extracted, imported and exported. We propose that if CO_2 suppliers already have the flow meter installed to directly measure the CO_2 stream at the point of capture, extraction, import and/or export, that facilities use the existing flow meter to measure CO_2 supply. We propose that facilities sample the composition of the gas on at least a quarterly basis to determine CO_2 composition of the CO_2 stream. If the necessary flow meters are not currently installed, CO_2 suppliers would use mass flow meters to measure the volume of the CO_2 stream transferred offsite.

We propose to require reporting on the volume of the CO_2 stream at the point of capture, extraction, import and export because this would provide information on the total quantity of CO_2 available for sale. Measuring at this initial point could provide additional information in the future on fugitive CO_2 emissions from onsite purification, processing, and compression of the gas. However, if the necessary flow meters are not currently in place, facilities may conduct measurements at the point of CO_2 transfer offsite.

We conclude that there is minimal incremental burden associated with this approach for CO_2 suppliers at industrial facilities or process units, CO_2 production wells, importers and exporters because these sites likely already have the necessary flow meters installed to monitor the CO_2 stream. In addition, facilities need to know CO_2 composition of the gas in order to ensure the gas meets appropriate specifications (e.g., food grade CO_2).

We also considered requiring CO_2 suppliers to report only on CO_2 sales, without determining the actual CO_2 composition of the gas sold. This is a relatively simple method, however, facilities already routinely measure the composition of the gas, providing greater certainty in the potential emissions data.

The methods proposed are generally consistent with existing GHG reporting protocols. Although existing protocols focus on accounting for fugitive emissions, and not quantity of CO_2 supplied, direct measurement is commonly the recommended approach for measuring fugitive emissions. We concluded that while direct measurement of fugitive emissions may not be common practice, and is therefore not proposed, measurement of CO_2 transfer is.

4. Selection of Procedures for Estimating Missing Data

Facilities with missing monitoring data on the volume of the CO_2 stream captured, extracted, imported, and exported should use the greater of the volume of the CO_2 stream transferred offsite or the quarterly or average value for the parameter from the past calendar year. The owners or operators of facilities monitoring emissions at the point of transfer offsite, that have missing monitoring data on the CO_2 stream transferred, may use the quarterly or average value for the parameter from the past calendar year.

Facilities with missing data on the composition of the CO_2 stream captured, extracted, imported, and exported should use the quarterly or average value for the parameter from the past calendar year.

5. Selection of Data Reporting Requirements

For CO_2 supply, the proposed monitoring method is based on direct measurement of the gaseous and liquid CO_2 streams. All CO_2 suppliers would report, on an annual basis, the measured volume of the CO_2 stream that is captured, extracted, imported and exported if the proper flow meter is installed to carry out these measurements. Facilities monitoring emissions at the point of transfer offsite would report the annual volume of the CO_2 stream transferred. All suppliers also would report, on an annual basis, the CO_2 composition of the gas sold. The end-use application of the supplied CO_2 (e.g., EOR, food processing) should also be reported, if known.

EPA proposes to collect data on the measured volume of the CO_2 stream captured, extracted, imported and exported, as well as gas composition because these form the basis of the GHG calculations and are needed for EPA to understand the emissions data and verify reasonableness of the reported emissions. EPA also proposes to collect information on the end use of the transferred CO_2, if known, because CO_2 can be used in emissive or non-emissive applications. Collecting data on the ultimate fate of the CO_2 stream can provide information on the potential emissions of CO_2 released to the atmosphere.

6. Selection of Records That Must Be Retained

Owners or operators of all CO_2 suppliers would be required to retain onsite all quarterly measurements for the volume of the CO_2 stream captured, extracted, imported and exported, and CO_2 composition. Where measurements are based on CO_2 transferred offsite, these quarterly measurements would be retained, along with CO_2 composition.

QQ. Mobile Sources

1. Definition of the Source Category

This section of the preamble describes proposed GHG reporting requirements for manufacturers of new mobile sources, including motor vehicles and engines, nonroad vehicles and engines, and aircraft engines.[118] It also seeks comment on the need to collect additional in-use travel activity and other emissions-related data from States and local governments and mobile source fleet operators. These proposed requirements and the requests for comments are based on EPA's authority under CAA Sections 114 and 208.

Not discussed in this portion of the preamble are proposed GHG reporting requirements related to transportation fuels (see Section V.MM of this preamble, Suppliers of Petroleum Products) and motor vehicle and engine manufacturing facilities (see Section V.C of this preamble, General Stationary Fuel Combustion Sources).

Total Emissions. For the U.S. transportation sector, the 2008 U.S. Inventory includes GHGs from the operation of passenger and freight vehicles within U.S. boundaries, natural gas used to power domestic pipelines, lubricants associated with mobile sources, and international bunker fuels purchased in the U.S. for travel outside U.S. boundaries. GHG emissions from these sources in 2006 totaled 2102.6 Tg CO_2e, representing 29.3 percent of total U.S. GHG emissions. Just under 79 percent of these emissions came from on-road sources, including passenger cars and light-duty trucks (58.8 percent), medium- and heavy-duty trucks (19.2 percent), buses (0.6 percent) and motorcycles (0.1 percent). Aircraft (including domestic military flights) accounted for 11.6 percent of transportation GHGs, ships and boats 5 percent, rail 2.8 percent, pipelines 1.5 percent, and lubricants 0.5 percent. These estimates primarily reflect GHGs resulting from the combustion of fuel to power U.S. transportation sources. These estimates do not include emissions from the operation of other non-transportation mobile equipment and recreational vehicles, which collectively accounted for over 2 percent of total U.S. GHG emissions.

GHGs produced by transportation sources include CO_2, N_2O and CH_4, which result primarily from the combustion of fuel to power these sources or from treatment of the exhaust gases, and HFCs, which are released through the operation, servicing and retirement of vehicle A/C systems. CO_2 is the predominant GHG from these sources, representing 95 percent of transportation GHG emissions (weighted by the GWP of each gas). HFCs account for 3.3 percent, N_2O for 1.6 percent, and CH_4 for 0.1 percent of transportation GHG emissions. EPA is proposing reporting requirements for each of these gases, where appropriate.

2. Selection of Proposed GHG Measurement, Reporting, and Recordkeeping Requirements

For the new vehicle and engine manufacturer reporting requirements proposed in this Notice, EPA intends to build on our long-established programs that control vehicle and engine emissions of criteria pollutants including hydrocarbons, NO_X, CO, and PM. These programs, which include emissions standards, testing procedures, and emissions certification and compliance requirements, are based on emission rates over prescribed test cycles (e.g., grams of pollutant per mile or grams per kilowatt-hour). Thus, we propose having manufacturers also report GHG emissions in terms of emission rates for this reporting program. It is important to note that this approach is somewhat different from the direct reporting of tons per year of emissions that is appropriate for the non-mobile source categories addressed elsewhere in this preamble. However, EPA would be able to use the GHG emission rate data from manufacturers with our existing models and other information to project tons of GHG emissions for the various mobile source categories.

Although the new reporting requirements proposed here focus on emission rates from new vehicles and engines, EPA also is very interested in continually updating and improving our understanding of the in-use activity and total emissions from mobile sources. Thus, we are seeking comment on the need to collect in-use travel activity and other emissions-related data from States and local governments and mobile source fleet operators. Section V.QQ.4 of this preamble describes the existing State and local government and fleet operator data that EPA currently collects and requests public comment on the need for, and substance of, additional reporting requirements.

3. Mobile Source Vehicle and Engine Manufacturers

a. Overview

As mentioned above, EPA is proposing GHG reporting requirements that fit within the reporting framework established for EPA's long-established criteria pollutant emissions control programs and vehicle fuel economy testing program. While the details of the programs vary widely among the vehicle and engine categories, EPA generally requires manufacturers to conduct emissions testing and report the resulting emissions data to EPA for approval on an annual basis prior to the introduction of the vehicles or engines into commerce. As a part of this process, since the early 1970s, EPA has collected criteria pollutant emissions data for all categories of vehicles and engines used in the transportation sector, including engines used in nonroad equipment (see Table QQ–1 of this preamble).

TABLE QQ–1. MOBILE SOURCE VEHICLE AND ENGINE CATEGORIES

Category
Light-duty vehicles
Highway heavy-duty vehicles (chassis-certified)
Highway heavy-duty engines
Highway motorcycles
Nonroad diesel engines
Marine diesel engines
Locomotive engines
Nonroad small spark ignition engines

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[118] The terms ''manufacturers'' and ''manufacturing companies'', as used in this section, mean companies that are subject to EPA emissions certification requirements. This primarily includes companies that manufacture vehicles and engines domestically and foreign manufacturers that import vehicles and 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 vehicles or engines.

TABLE QQ–1. MOBILE SOURCE VEHICLE AND ENGINE CATEGORIES—Continued

Category
Nonroad large spark ignition engines
Marine spark ignition engines/personal watercraft
Snowmobiles
Off-highway motorcycles and all terrain vehicles
Aircraft engines

For purposes of EPA certification, manufacturers typically group vehicles/engines with similar characteristics into families and perform emission tests on representative or worst-case vehicles/engines from each family. Integral to EPA's existing certification procedures are well-established methods for assuring the completeness and quality of reported emission test data. We are proposing to require manufacturers to measure and report GHG emissions data as part of these current emissions testing and certification procedures. These procedures, appropriate here because of the long-standing history and structure of mobile source control programs, are necessarily different from the monitoring-based methods proposed for other sources elsewhere in this notice.

After a discussion of the proposed small business threshold, the following subsections describe the proposed GHG emissions measurement and reporting requirements for manufacturers. As discussed in those subsections, some manufacturers already measure and report some GHG emissions, some measure but do not have to report GHG emissions, and others would need to measure and report for the first time. We propose that the new measurement and reporting requirements apply beginning with the 2011 model year, although we encourage voluntary measurement and reporting for model year 2010.

b. Selection of a Reporting Threshold

In most of EPA's recent mobile source regulatory programs for criteria pollutants, EPA has applied special provisions to small manufacturers. EPA proposes to exempt small manufacturers from the GHG reporting requirements. We define ''small business'' or ''small volume manufacturer'' separately for each mobile source category. These definitions were established in the regulations during the rulemaking process for each category, which included consultation with small entities and with the Small Business Administration. We're proposing to use these same definitions in each case for the reporting requirements exemption. We believe that this exemption would avoid the relatively high per-vehicle or per-engine reporting costs for small manufacturers without detracting from the goals of the reporting program, as discussed below.

It is important to note that this ''threshold'' would differ from the approach proposed for other source categories discussed in Section V of this preamble. That is, EPA would not have manufacturers determine their eligibility based on total tons emitted per year. As discussed above, EPA's current mobile source criteria pollutant control programs are based on emissions rates over prescribed test cycles rather than tons per year estimates. Since we are proposing to build on our existing system, we believe that a threshold based on manufacturer size is appropriate for the mobile source sector. Although the emission rates of some vehicles and engines would not be reported, we do not believe this is a concern because the technologies—and thus emission rates—from larger manufacturers represent the same basic technologies and emission rates of essentially all vehicles and engines. It is also worth noting that the manufacturers that meet the small manufacturer definitions represent a very small fraction of overall vehicle and engine sales. For nine out of the twelve non-aircraft mobile source categories (there are currently no small aircraft engine manufacturers), we estimate that sales from small manufacturers represent less than 10 percent of overall sales (for eight of these categories, including light-duty vehicles, small manufacturers account for less than 3 percent of sales). For the remaining three categories (highway motorcycles, all terrain vehicles/off-road motorcycles, and small spark ignition engines) we estimate that small entities account for less than 32 percent of sales.

Please see the discussion of our compliance with the RFA in Section IX.C of this preamble. We request comments on our proposed approach for the reporting threshold for mobile source categories.

c. Light-Duty Vehicles

We propose that manufacturers of passenger cars, light trucks, and medium-duty passenger vehicles measure and report emissions of CO_2 (including A/C-related CO_2), CH_4, N_2O, and refrigerant leakage.[119] Existing criteria pollutant emissions certification regulations, as well as fuel economy testing regulations, already require manufacturers to measure and report CO_2 for essentially all of their vehicle testing. Requiring manufacturers to also measure and report the other GHGs emitted by these vehicles, as proposed in this Notice and discussed below, would introduce a modest but reasonable additional testing and reporting burden.

For CH_4 and N_2O, we propose that manufacturers begin to measure these emissions as a part of existing emissions certification and fuel economy test procedures (FTP, SFTP, HFET, *et al.*), if they are not already doing so, and then to report those emissions in the same cycle-weighted format that they report other emission results under the current certification requirements. Because such testing has not generally been required, some manufacturers would need to install additional exhaust analysis equipment for the measurement of CH_4 and/or N_2O. In most cases, both of these types of new analyzers could be added as modular units to existing test equipment.

In the case of N_2O, since this pollutant has not previously been included in the certification testing process, it is necessary to introduce a new analytical procedure for the measurement of N_2O over the FTP. This is not the case for CH_4, however, since an analytical procedure for CH_4 testing already exists. We propose that manufacturers use an N_2O procedure found in the regulatory language associated with this notice that would be based largely on the procedures currently used to measure CO_2 and CO, using nondispersive infrared measurement technology. In addition, EPA is proposing a ''scrubbing'' stage as a part of this procedure that would remove sulfur compounds that can contribute to N_2O formation in the sample bag. (See proposed 40 CFR 1065.257 and 1065.357 for the proposed N_2O measurement procedures.) EPA requests comments on all aspects of the proposed N_2O measurement procedure, including potential alternate methods with equal or better analytical performance.

Measuring and Reporting A/C-Related CO_2. Manufacturers of light-duty vehicles, unlike manufacturers of heavy-duty and nonroad engines, sell their products as complete engine-plus-vehicle combinations that include the vehicles' A/C systems. Thus, we believe it is appropriate that these manufacturers report A/C-related emissions as a part of their existing vehicle certification requirements. EPA does not currently require these manufacturers to measure or report the A/C-related CO_2 emissions (or the

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[119] See 40 CFR 1803–01 for full definitions of ''light-duty vehicle''.

leakage of refrigerants, as discussed below) under current regulations. We propose that these manufacturers begin to measure A/C-related CO_2 emissions (i.e., the indirect CO_2 emissions resulting from the additional load placed on the engine by an operating A/C system), using a proposed new test cycle, which is described below. This testing would not require new equipment, and the proposed test cycle is similar to one that exists in many State Inspection & Maintenance (I/M) programs.

The current FTP for light-duty vehicles is performed with the A/C turned on only during the SC03, or ''air conditioning,'' test procedure. This test is used to verify emissions compliance in a ''worst-case'' situation when the A/C system is operating under relatively extreme conditions. The SC03 is also used in the 5-cycle fuel economy calculation for fuel economy labeling. Thus, although the SC03 test results in a value for CO_2 emissions (in grams per mile), the incremental increase of CO_2 resulting from operation of the A/C system, especially in a more typical situation, is not quantified.

In order to provide for consistent, accurate measurement of A/C-related CO_2 emissions, EPA proposes to introduce a specifically-designed test procedure for A/C-related CO_2 emissions. Manufacturers would run this proposed test, the A/C CO_2 Idle Test, with the engine idling, upon completion of an emissions certification test—such as the FTP, highway fuel economy, or US06 test. The proposed A/C CO_2 Idle Test is similar to the ''Idle CO'' test, which was once a part of vehicle certification, and is still used in State I/M programs (see 40 CFR part 51, subpart S, Appendix B).

Within each vehicle model type, various configurations of engine and cooling system options can be expected to have somewhat different A/C-related CO_2 performance.[120] However, we believe that vehicles sharing certain technical characteristics would generally have similar A/C-related CO_2 emissions. Specifically, vehicles with the same engine, A/C system design, and interior volume would be expected in most cases to have similar A/C-related CO_2 performance. In order to minimize the number of new tests that manufacturers would be required to perform, EPA is proposing that manufacturers be allowed to select a subset of vehicles for A/C CO_2 Idle Testing, each of which would represent the performance of a larger group of vehicles with common A/C-related technical characteristics. We believe that in most cases the vehicles that manufacturers currently test for fuel economy purposes (as described in 40 CFR 600.208(a)(2)) would generally also capture the key engine-A/C system-vehicle configurations that may exist within a given model type. The complete set of our proposed criteria for manufacturers to meet in selecting the representative vehicles for the A/C CO_2 Idle Test is found in the regulatory language in the proposed rule (see proposed 40 CFR 86.1843–01, ''Air conditioning system commonality'').

The A/C CO_2 Idle Test would compare the additional CO_2 generated at idle with the A/C system in operation to the CO_2 generated at idle with the A/C system off. Manufacturers would run the test with the vehicle's A/C system operating under complete control of the climate control system and for a sufficient length of time to stabilize the cabin conditions and tailpipe emission levels. EPA believes that this test would account for the CO_2 contributions from most of the key A/C system components and modes of operation.

The additional CO_2 generated when the A/C is operated during the Idle Test would then be normalized to account for the interior cabin volume of the vehicle. This normalization is necessary because the size and capacity of an A/C system is related to the volume of air that an A/C system must cool. Rather than simply reporting the vehicle's CO_2 emissions, this normalization would provide a more appropriate metric of CO_2 emissions to compare systems that must cool relatively larger volumes with those that cool smaller volumes. EPA proposes that the interior cabin volume be defined as the volume of air that the air conditioner cools, which includes the volume of space used by passengers and, in some vehicles, the volume used for cargo. The proposed calculation of interior cabin volume is adapted from an industry protocol, Society of Automotive Engineers (SAE) Surface Vehicle Standard J1100.

The proposed A/C CO_2 Idle Test would require three approximately 10-minute periods of CO_2 emissions measurement once the vehicle's cabin conditions and climate control system have stabilized in order to quantify the A/C related CO_2. The test would be run at 75 °F, the standard temperature of the FTP. As discussed below, EPA considered proposing a more complex procedure that would be performed at a higher temperature, such as the 95 °F used in the SC03 test. However, we believe that A/C-related CO_2 can be accurately demonstrated on the Idle Test at 75 °F, avoiding the significant facility and testing issues associated with higher temperature testing. In order to better simulate ''real world'' idling conditions, we propose that the A/C CO_2 Idle Test be performed with the engine compartment hood and windows closed and without operating the test site cooling fan that is usually used to simulate the motion of the vehicle on the road.

The proposed A/C CO_2 Idle Test procedure specifies how climate control systems, whether manual or automatic, would need to be set to appropriately simulate the maximum and minimum cooling demands on the A/C system. CO_2 exhaust emission measurements, in grams per minute, would be taken during both of these modes. Manufacturers would conduct the idle test following the completion of a FTP certification test, a fuel economy test, or a test over the US06 cycle. As discussed above, manufacturers would measure the change in CO_2 due to A/C operation in grams per minute and then would divide this value by the interior volume in cubic feet, for an A/C CO_2 emission value in terms of grams per minute per cubic foot. The manufacturer would report this value to EPA with other emission results.

EPA also requests comment on three different approaches that could be used alone or in combination with the proposed A/C CO_2 Idle Test or with each other. Each of these tests would capture a somewhat different set of aspects of A/C-related CO_2 emissions. First, EPA is seeking comment on basing reporting requirements on the SC03 test (or some variant of this test), which, as described above, is designed to simulate more extreme driving conditions than the standard certification tests. Using the SC03 test to determine A/C-related CO_2 performance would likely require manufacturers to run tests in additional modes or to repeat the test in order to capture more real-world A/C usage (i.e., a stabilized cabin temperature). Therefore such an approach could involve significant modifications to the SC03 test procedure. The rationale for considering such an adapted SC03 test would be to characterize more systemic technological features (such as thermal management and transient A/C control) that may not be captured in a 75 °F idle test or a bench test (as discussed below).

Second, EPA is seeking comment on basing reporting requirements on a ''bench'' test procedure similar to the one being developed by the SAE and the University of Illinois, which was employed to measure A/C efficiency

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[120] In the existing regulations covering vehicle emissions certification, under 'Definitions' in 40 CFR 600.002–85(a)(15), ''model type'' means a unique combination of car line, basic engine, and transmission class.

improvements for the industry/government Improved Mobile Air Conditioning project. This bench test only measures the power consumption of the A/C compressor with simulated loads, and is not integrated into a vehicle (as would be the case in the proposed A/C CO_2 Idle Test, which is a ‘‘chassis,’’ or whole-vehicle, test). The purpose of the bench test for characterizing A/C-related CO_2 emissions would be to have a relatively repeatable test that could represent a variety of temperature and humidity conditions around the country. Unlike a chassis test, there would not be a direct connection to a vehicle's interior volume, and we would need to develop assumptions about a vehicle's interior volume in order to normalize the results. This test procedure might be less expensive than a modified SC03 test.

Finally, EPA is seeking comment on basing reporting requirements on design-based criteria for characterizing A/C-related CO_2 emissions. Design-based criteria would be conceptually similar to the ones proposed for leakage emissions characterization as described below. A manufacturer would choose technologies from a list provided by EPA in the rule where we would specify the A/C-related CO_2 characteristics associated with each major component and technology, including system control strategy and systems integration. While such a design-based approach might capture the expected CO_2 emissions of individual components and controls, it would not necessarily capture overall system A/C-related CO_2 (when the A/C components would be integrated into the vehicle and would interact with the engine, cabin conditions, and other vehicle characteristics, such as the under-hood environment).

Calculating and Reporting a ‘‘Score’’ for A/C-Related Refrigerant Leakage. As part of most of EPA's existing mobile source emissions testing and certification programs, where robust test procedures have been developed and are in widespread use, EPA has relied on ‘‘performance-based’’ approaches, where emissions are measured directly during vehicle or engine operation to determine emission levels. Examples of performance-based test procedures include the FTP and the proposed A/C CO_2 Idle Test discussed above. In the case of A/C refrigerant leakage, where it is known that leakage of refrigerants with high GWPs occurs, a reliable, performance-based test procedure to measure such emissions from a vehicle does not yet exist. Instead, we are proposing a ‘‘design-based’’ approach to establish a vehicle's expected refrigerant leakage emissions.

Under our proposal, each key A/C-related component and system would be assigned an expected rate of refrigerant leakage, in the form of a leakage ‘‘score,’’ in terms of grams per year. These individual scores would be added to result in an overall leakage score for the vehicle. We propose that manufacturers establish an overall leakage score for the same test vehicle(s) on which they run the A/C CO_2 Idle Test, as described above.

The cooperative industry and government Improved Mobile Air Conditioning Program referenced above also has developed a comprehensive set of leakage scores that EPA proposes to use to represent the significant sources of A/C refrigerant leakage from newer vehicles. The Improved Mobile Air Conditioning Program and the SAE have established a template for calculating individual leakage scores based on the quantity and type of components, fittings, seals, and hoses utilized in a specific A/C system design; this template is known as the SAE Surface Vehicle Standard J2727. EPA is proposing a set of component and system leakage scores, based closely on J2727, but expanded to place greater emphasis on characterizing leakage emissions later in the vehicle's life. Like the J2727, this proposed EPA protocol would associate each technology or system design approach with a specific leakage score. Each score would be a design-based, ‘‘leakage-equivalent’’ value that would take into account expected early-in-life refrigerant leakage from the specified components and systems. Manufacturers would report this value to EPA on their application for certification.

In addition, we request comment on the whether other A/C design considerations, such as use of alternative refrigerants, monitoring refrigerant leakage (with fault storage and indicators), and minimizing refrigerant quantity, should be used in determining an A/C leakage score.

d. Highway Heavy-Duty Diesel and Gasoline Vehicles and Engines

EPA's highway heavy-duty vehicle and engine emissions testing and certification programs generally cover vehicles above 8,500 pounds Gross Vehicle Weight Rating.[121] For most large trucks, manufacturers are required to measure and report criteria air pollutant emissions data for engines rather than vehicles. Engine manufacturers measure and report emissions prior to the engines being sold to separate companies that build trucks or buses and install engines in them. Manufacturers of gasoline-fueled complete vehicles below 14,000 pounds Gross Vehicle Weight Rating, such as large pick-ups and SUVs, are required to measure and report vehicle emissions, as do manufacturers of light-duty vehicles. These vehicles are described as ‘‘complete’’ vehicles because the vehicles leave the primary manufacturing facility fully assembled, with the engine and associated hardware installed and the load-carrying container attached.

Manufacturers That Certify Engines. EPA proposes to require manufacturers to report CO_2 emissions from highway heavy-duty diesel and gasoline engines. All manufacturers currently measure CO_2 as an integral part of calculating emissions of criteria pollutants, and some report CO_2 emissions in some form. We propose that engine manufacturers report CO_2 to EPA with criteria pollutant emission results and, as with the criteria emissions, report the CO_2 emissions in terms of brake-specific emissions (i.e., in units of grams of CO_2 per brake-horsepower-hour).

We also propose that highway heavy-duty engine manufacturers measure and report CH_4 emissions. This would require most manufacturers to install CH_4 exhaust analytical equipment or to arrange for testing at another facility. This equipment is usually designed to be installed as a modular addition to existing analytical equipment. Procedures for analyzing CH_4 are currently in place.

Finally, we also propose that these manufacturers measure and report N_2O. As with CH_4, this would require most manufacturers to install new, usually modular, N_2O exhaust analytical equipment, or to arrange for testing at another facility. Because it has not been necessary in the past to measure N_2O, we are proposing a new procedure for measuring N_2O (see proposed 40 CFR 1065.257 and 1065.357).

As with CO_2, manufacturers would measure both CH_4 and N_2O as a part of the existing FTP for heavy-duty engines and report the results to EPA with other criteria pollutant emission test results.

Manufacturers That Certify Complete Highway Heavy-Duty Vehicles. We propose that manufacturers certifying complete heavy-duty vehicles be subject to the same measurement and reporting requirements as manufacturers of heavy-duty engines. Thus, as described above, these manufacturers would report the CO_2 emissions they are currently measuring as part of criteria air

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[121] See 40 CFR 1803–01 for full definitions of ‘‘heavy-duty vehicle’’ and ‘‘heavy-duty engine.’’

pollutant emissions testing and would additionally measure and report CH_4 and N_2O. Although vehicle emissions testing (also known as ''chassis testing'') is different than engine-only testing, measurement procedures are the same, and we are proposing measurement and reporting requirements for complete heavy-duty vehicles that are essentially identical to our proposed requirements for heavy-duty engines.

However, manufacturers of complete heavy-duty vehicles, unlike heavy-duty engine manufacturers, are generally responsible for installing the vehicle's A/C equipment. For this reason, we propose that these manufacturers be responsible for reporting A/C-related emissions, in exactly the same ways that we are proposing for light-duty manufacturers, as described in Section V.QQ.3.c of this preamble. Thus, we propose that these manufacturers perform the A/C CO_2 Idle Test and report the A/C-related CO_2 emissions. We also request comment on the potential applicability of the alternate A/C CO_2 measurement procedures discussed above to manufacturers of complete heavy-duty vehicles. In addition, we propose that these manufacturers calculate and report an overall A/C refrigerant leakage ''score,'' using the same assigned component and system scores we have developed for the proposed light-duty scoring system.

Vehicle Manufacturers That Install Certified Engines. We are not proposing any requirements for the heavy-duty truck and bus manufacturers that install certified engines into their vehicles. These truck manufacturers currently are not required to certify their trucks to EPA emissions standards and do not conduct emissions testing. However, we recognize that these vehicles are generally equipped with A/C systems by the truck or bus manufacturer. We request comment on the appropriateness, feasibility, and cost of extending some form of the proposed A/C CO_2 Idle Test and refrigerant leakage score requirements discussed above for manufacturers of complete heavy-duty trucks to these truck and bus manufacturers as well. In addition, we request comment on how original-equipment or aftermarket auxiliary power units—if used to provide power for cabin A/C—might be incorporated into a GHG reporting program.

e. Nonroad Diesel Engines and Nonroad Large Spark-Ignition Engines

Nonroad diesel engines and nonroad large spark-ignition (generally gasoline-fueled) engines are used in a wide variety of construction, agricultural, and industrial equipment applications. However, these engines are very similar (in terms of design, technology, and certification process) to their counterparts certified for highway operation. Given these similarities, we propose that manufacturers of these engines measure and report CO_2, CH_4, and N_2O in the same manner as manufacturers of highway heavy-duty diesel and gasoline engines, as described earlier in this section of the preamble.

Like highway heavy-duty truck and bus manufacturers that use certified engines, nonroad diesel equipment manufacturers install certified engines into their equipment but do not certify their equipment. As with trucks and buses, this equipment is often equipped with A/C systems. While we are not proposing any reporting requirements for nonroad equipment manufacturers, we request comment on the appropriateness, feasibility, and cost of extending some form of the proposed A/C CO_2 Idle Test and refrigerant leakage score reporting requirements discussed above to nonroad equipment manufacturers. We also request comment on extending A/C-related GHG reporting requirements to transportation refrigeration units that are equipped with separate engines that are certified under EPA's nonroad engine program.

f. Nonroad Small Spark-Ignition Engines, Marine Spark-Ignition Engines, Personal Watercraft, Highway Motorcycles, and Recreational Engines and Vehicles

There is a large range of spark-ignition engines in this category including engines used in portable power equipment, snowmobiles, all terrain vehicles, off-highway motorcycles, automotive-based, inboard engines used in marine vessels. For purposes of this proposed reporting rule, we also include highway motorcycles, which are tested as complete vehicles. We are proposing that manufacturers measure and report CO_2, CH_4, and N_2O emissions for these engines and vehicles. As part of existing criteria pollutant emissions testing requirements, manufacturers must determine the amount of fuel consumed either through direct measurement or through chemical balances of the fuel, intake air, and exhaust. With the ''chemical balance'' approach, CO_2 levels in the intake air and exhaust are measured (along with either the intake air flow rate or exhaust flow rate), and fuel consumption is calculated based on fuel properties and the change in CO_2 level between the intake and exhaust flows. (CO_2 levels with associated flow rates can be used to calculate a CO_2 emission rates). Alternatively, when a ''direct measurement'' approach is used to determine fuel consumption, there is no need to measure CO_2 levels in the intake air or exhaust. For manufacturers that generally use only the direct measurement approach, new analysis equipment might be required to measure CO_2 levels in the intake air and exhaust. We propose that manufacturers measure and report cycle-weighted CO_2 emissions (in the same ''grams-per-unit-of-work'' format used for criteria pollutant emissions reporting) for all engines in these categories, regardless of the method used to determine fuel consumption. We also propose that highway motorcycle manufacturers measure and report CO_2 in terms of grams per mile.

For CH_4, many of the engines described above are subject to ''total'' hydrocarbon, or ''hydrocarbon + NO_X '' standards (as opposed to ''non-CH_4'' hydrocarbon standards applying to some other categories), and thus CH_4 emissions may not typically be measured. In these cases, the manufacturers would need to install CH_4 emissions analysis equipment. We propose that manufacturers report cycle-weighted CH_4 emissions for these engines and for highway motorcycles.

Finally, we are proposing that manufacturers also report the cycle-weighted N_2O emissions for these engines and for highway motorcycles. As with CH_4, manufacturers would likely need to install N_2O emissions analysis equipment. The proposed new procedure for measuring N_2O is found in the draft regulations (40 CFR 1065.257 and 1065.357).

g. Locomotive and Marine Diesel Engines

We are proposing that manufacturers of locomotive and marine diesel engines—including those who certify ''remanufactured'' engines—measure and report CO_2, CH_4, and N_2O emissions for locomotive and marine diesel engines. Manufacturers of these engines already measure CO_2 emissions during the course of existing criteria air pollutant emission testing requirements, but generally do not report this to EPA. For manufacturers of these engines, we propose that CO_2 emissions be reported in the same cycle-weighted, work-based format (i.e., g/bhp-hr) as used for criteria pollutant emissions reporting. For C3 marine diesel engines, we are requesting comment on whether indirect CO_2 measurement (i.e., calculating the CO_2 levels based on fuel flow rate and fuel composition parameters) is an appropriate method for those manufacturers that do not utilize CO_2

analysis equipment in the course of emission testing.

Since diesel locomotives are subject to ''total'' hydrocarbon standards (which include CH_4 in the measured and reported hydrocarbon value), as opposed to ''non-CH_4'' hydrocarbon standards (which do not include CH_4), manufacturers typically do not measure CH_4 emissions. With the exception of C3 marine diesel engines (which do not have any ''hydrocarbon'' emission standards, and are not required to measure hydrocarbon or CH_4 emissions), we propose that manufacturers measure and report CH_4 emissions as a part of certification. To do so, we expect that some manufacturers would need to install equipment for analyzing CH_4 emissions.

We also propose that manufacturers—except for C3 marine—measure and report N_2O emissions as well. For C3 marine diesel engines, we are requesting comment on the appropriateness and feasibility of requiring N_2O measurement and reporting on the small number of engines represented by this category. As with CH_4, we expect that most or all manufacturers would need to install N_2O emissions analysis equipment. The proposed new procedure for measuring N_2O is found in the proposed regulations (40 CFR 1065.257 and 1065.357).

h. Aircraft Engines

This category comprises turbofan, turbojet, turboprop (turbine-driven propeller), turboshaft (turbine-driven helicopters), and piston propulsion engines for commercial, air taxi, and general aviation aircraft. In the case of turbofan and turbojet engines of rated output (or thrust) greater than 26.7 kilonewtons, manufacturers of these engines are already measuring and recording CO_2 emissions as part of existing criteria air pollutant emission requirements for the landing and takeoff cycle. In this notice, we propose that manufacturers measure, record and report CO_2 separately for each mode of the landing and takeoff (LTO) cycle used in the emission certification test, as well as for the entire landing and takeoff cycle. (The modes of the landing and takeoff cycle are taxi/idle, takeoff, climb out, and approach.)

CH_4 may be emitted by gas turbine engines during idle and by relatively older technology engines, but recent data suggest that little or no CH_4 may be emitted by some newer engines. Manufacturers of turbofan and turbojet engines of rated output greater than 26.7 kilonewtons are currently measuring hydrocarbon emissions as part of existing criteria air pollutant emissions testing, and CH_4 is included in the total hydrocarbon measurement. We propose that manufacturers of these engines begin to separately measure and report CH_4 for all engines in this category for which they are currently required to measure and record criteria air pollutant emissions as part of the certification process. Some manufacturers may need to acquire CH_4 emissions analysis equipment. We ask for comment on the degree to which engine manufacturers now have the needed equipment in their certification test cells to measure CH_4.

Since little or no N_2O is formed in modern gas turbine engines, we are not proposing to require N_2O measurement or reporting.

Within the mobile source sector, NO_X is a climate change gas unique to aviation. As required in 40 CFR part 87, manufacturers of turbofan and turbojet engines of rated output greater than 26.7 kilonewtons measure and record NO_X emissions in each of the four LTO test modes, and these manufacturers must comply with the LTO NO_X emission standard (for the entire LTO cycle). EPA asks for comment on whether NO_X emissions in the four LTO test modes and for the overall LTO cycles should be reported under the provisions of this proposal, as they are now not reported to EPA for public consideration as is the case with all other mobile sources.[122]

EPA does not currently require manufacturers of piston engines (used in any application) to measure, record or report criteria air pollutant or GHG emissions, and no official FTP exists for these engines.[123] For these reasons, we are not proposing any GHG reporting requirements for these engines. However, we request comment on the potential costs and benefits of reporting requirements for GHG emissions from these engines, including how an appropriate emission test cycle might be designed. We also ask for comment on whether the requirements should be applied to turbofan and turbojet engines of rated output less than or equal to 26.7 kilonewtons, turboprop engines, and turbo shaft engines which are not now regulated under 40 CFR 87 requirements for criteria air pollutant emissions.[124]

4. Request for Comments on Travel Activity and Other In-Use, Emissions-Related Data

Travel activity and other emissions-related data from State and local governments and fleet operators are critical to understanding the overall GHG contribution of the mobile source sector. These data serve the important role of reflecting real-world conditions and capturing activity levels (e.g., distance traveled and hours operated) from all vehicles and engines, which can complement data that manufacturers report on expected emissions rates from new vehicles and engines. EPA already receives some in-use data through existing reporting programs. The purpose of this section of the preamble is to describe these existing data sources and to request public comment on the need for additional data. In Section V.QQ.4.a of this preamble, we describe data currently reported by State and local governments, and request comment on the potential benefits of the collection of additional data. In Section V.QQ.4.b of this preamble, we highlight the types of data reported by fleet operators as part of the SmartWay Transport Program or other Federal programs, and request comment on the value of other potential reporting requirements.

a. Travel Activity and Other Data From State and Local Governments

Travel activity is a term EPA primarily uses for on-road vehicle activity and includes the number and type of vehicles and the distance they travel. State and local governments collect many types of travel activity data, including VMT by vehicle type and model year, fuel type, and/or functional road class (e.g., limited access highways, arterials with traffic signals, etc.). Other types of emissions-related data include vehicle operation and environmental conditions that can affect emissions during travel, such as idling practices and ambient temperature. Travel activity and other emissions-related data can vary over time, between regions, and between metropolitan and rural areas within a given State. EPA can use these data to evaluate how changes in vehicle

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[122] Currently, these engine manufacturers voluntarily report criteria air pollutant emissions for the LTO cycle to the International Civil Aviation Organization.

[123] EPA received an administrative petition asking the agency to determine under section 231 of the CAA whether lead emissions from general aviation (piston engine) aircraft cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, and, if so, to establish standards for such emissions. Today's proposal regarding GHG emissions from piston-engine aircraft is not intended to respond in any way to the petition regarding general aviation lead emissions.

[124] Existing regulations in 40 CFR part 87 include smoke number standards for turbofan and turbojet engines of rated output less than or equal to 26.7 kilonewtons and turboprop engines of rated output greater than or equal to 1,000 kilowatts. Requirements for the term turboshaft engine are currently not specified in 40 CFR part 87.

technology or travel activity can affect emissions.

EPA currently collects on-road mobile source data to better understand criteria air pollutant emissions, and some of these data can also be used to understand GHG emissions. For example, States provide VMT data to the Agency through the AERR.[125] EPA currently relies on AERR data to develop the NEI[126] which is used for, among other things, evaluating Federal vehicle and fuel standards for criteria pollutants and mobile source air toxics.

The AERR requires State air agencies to report mobile source data, including VMT data at the county level by roadway type,[127] every three calendar years beginning with the 2002 calendar year (i.e., states report mobile source inventories for 2005, 2008, 2011, etc.). The most recent submissions are for the 2005 calendar year. Although not required by the rule, EPA understands that some State air agencies consult with State and local transportation agencies in preparing VMT data submissions. States also submit other information that can be used to estimate criteria pollutant emissions, e.g., age and speed distributions of vehicles by vehicle class and roadway type, fuel properties by county, month, and year, and temperature and humidity data by county, month, and year. The AERR also requires certain emissions-related information, such as activity data (e.g., hours/day of operation), for nonroad mobile sources, according to similar submission requirements as described above.

In addition to EPA's existing data collection requirements, there are other sources of travel activity and emissions-related data. DOT currently collects statewide VMT data for urban and rural roadway types through its Highway Performance Monitoring System. DOT and DOE also publish statistical reports such as the Census Transportation Planning Package, National Personal Transportation Survey, and the Urban Mobility Study. In the past, the U.S. Census Bureau conducted the Vehicle Inventory and Use Survey, which provided valuable data on the physical and operational characteristics of the nation's private and commercial truck populations.[128] In specific geographic areas, agencies such as metropolitan planning organizations, State departments of transportation, transit agencies, air quality agencies, and county planning agencies also collect and project State and local travel activity and emissions data to meet Federal requirements, such as DOT's transportation planning requirements and EPA's SIP and transportation conformity requirements.

In light of the existing data available to EPA, the Agency is not proposing any new reporting requirements for State and local governments at this time. However, EPA is interested in requesting comment on several topics.

(1) Should EPA require States, local governments, or other entities to report additional travel activity or emissions-related data beyond what is required under EPA's existing reporting requirements? How would such data be used to inform future climate policy?

(2) What, if any, are the specific gaps in the currently reported travel activity or emissions-related data that are important for understanding on-road mobile source GHG emissions? For example, would it be helpful for EPA to better understand State- or county-level VMT growth rates (e.g., based on VMT data collected over the past five or ten years or other methodology) or emissions data related to the freight sector (e.g., hours of long-duration truck idling or truck data that was previously provided by the Vehicle Inventory and Use Survey)? What is the quality of currently reported State and local VMT data, and should travel activity and emissions-related data quality be improved?

(3) Is it sufficient to collect travel activity or emissions-related data every three years as currently required, or should EPA collect such data on an annual basis, similar to other collections discussed in today's action?

(4) Should EPA consider any threshold(s) for States, local governments, or other entities that must report additional travel activity or other emissions-related data? For example, should additional data be reported only from larger metropolitan areas with more sophisticated transportation systems (e.g., metropolitan planning organizations with an urbanized population of 200,000 or more)?

(5) What nonroad activity data is of most interest for understanding GHG emissions, and should EPA consider any additional requirements for reporting such data beyond what is currently required?

b. Mobile Source Fleet Operator Data

Mobile source fleet operators[129] are in a unique position to collect data that reflect real-world conditions that are difficult to integrate into vehicle and engine testing procedures or to capture in travel activity surveys. Fleet operator data includes fuel consumption, which can be robustly converted into CO_2 emissions, distance traveled, and the number and/or weight of passengers and freight transported. EPA currently collects fleet operator data from sources that include DOT surveys such as the Vehicle Inventory and Use Survey (described in Section V.QQ.4.a of this preamble, but discontinued in 2002), in-use testing as part of vehicle and engine manufacturer compliance programs, ad-hoc internal and external field studies and surveys, and voluntary programs such as the SmartWay Transport Partnership. The rest of this section of the preamble describes the data EPA collects as part of our voluntary programs as well as the DOT's (DOT) rail and aviation fleet reporting requirements, and requests comment on the need for, and substance of, any additional reporting requirements.

EPA believes that one of the most important functions of collecting fleet operator data is to inform operators about their emissions profiles and to shed light on opportunities to reduce emissions through the use of clean technologies, fuels, and operational strategies. Through the SmartWay Transport Partnership program, EPA requires participating truck and rail equipment operators, or ''partners,'' to report data as part of their voluntary commitment to measure and improve the environmental performance of their fleets. EPA uses this data to evaluate partner performance. Partners report annually on their fuel consumption by fuel type, miles traveled, and tonnage of freight carried. Truck operators also have the option of reporting the configuration and model year of each of their trucks. There is no minimum emissions reporting threshold for either truck or rail operators. EPA requires partners to report their annual data

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[125] EPA promulgated the AERR in December 2008 (73 FR 76539) (40 CFR part 51, subpart A). EPA promulgated the AERR to consolidate, reduce, and simplify the current requirements; add limited new requirements; provide additional flexibility to states in the ways they collect and report emissions data; and accelerate the reporting of emissions data to EPA by state and local agencies. The AERR replaces the Consolidated Emissions Reporting Rule (CERR) which was promulgated in June 2002 (67 FR 39602) in part to streamline existing periodic emissions inventory requirements for criteria pollutants.

[126] EPA prepares a national database of air emissions information from numerous state and local air agencies, from tribes, and from industry: *http://www.epa.gov/ttn/chief/eiinformation.html*.

[127] Under the AERR, VMT data should reflect both roadway type and vehicle type information.

[128] The primary goal of the Vehicle Inventory and Use Survey database was to produce national and state-level estimates of the total number of trucks. This survey was conducted every 5 years, until it was discontinued in 2002.

[129] For the purpose of our request for comments, ''fleet operators'' are defined as entities that have operational control over mobile sources. ''Operational control'' is defined as having the full authority to introduce and implement operational, environmental, health, and safety policies.

through the SmartWay Freight Logistics Environmental and Energy Tracking performance model.[130] The SmartWay Freight Logistics Environmental and Energy Tracking model translates the partners' fuel consumption data into CO_2 emissions based on EPA's default emissions factors for fuels. EPA does not publicly release individual partners' emissions data. At present, the SmartWay Transport Partnership has received annual data from more than 400 trucking companies and all seven Class I rail companies. These partners' CO_2 emissions represent approximately 20 percent and 80 percent, respectively, of the 2005 national inventory of trucking and rail GHG emissions.[131]

EPA's Climate Leaders program also requires participating companies that operate mobile sources to report CO_2, N_2O, CH_4, and HFC emissions from those sources annually as a part of their voluntary commitment to develop a comprehensive, corporate-wide GHG inventory. There are no minimum emissions reporting thresholds for mobile sources. Companies quantify mobile source emissions based on the Climate Leaders reporting protocol,[132] which outlines several methods for calculating CO_2 including applying EPA's default factors to fuel consumption data. The reporting protocol also includes default N_2O and CH_4 factors for non-road fuel consumption and on-road miles traveled by vehicle model year or technology type. Additionally, the reporting protocol includes default HFC leakage factors for mobile A/C units. As with SmartWay, EPA does not publicly release individual participating companies' emissions data. Currently, the Climate Leaders program has received mobile source data from 37 companies representing roughly 0.09 percent of the 2005 national inventory of transportation sector GHG emissions.[133]

In addition, DOT collects and publicly releases extensive data from rail and aircraft operators. All seven Class I[134] rail operators are required to report annual fuel consumption and ton-miles, among other data, to the Surface Transportation Board per the reporting guidelines in 49 U.S.C. 11145. Large certificated air carriers,[135] small certificated air carriers, and commuter air carriers with more than $20,000,000 in annual operating revenues must report monthly fuel usage data to the Bureau of Transportation Statistics via Form 41 pursuant to 14 CFR part 217 and part 241. Large certificated air carriers must also report monthly traffic data including distance traveled, tonnage of freight transported, and number of passengers transported.

In light of the existing data available to EPA, the Agency is not proposing mandatory reporting requirements for mobile source fleet operators, but is requesting comments on the need for, and substance of, potential reporting requirements at this time. We request comment on the following questions:

(1) Should fleet operators be required to report to EPA outside of voluntary participation in the SmartWay or Climate Leaders programs? How would this data be used to inform future climate policy?

(2) Are there certain categories of mobile sources that should be included or excluded in potential reporting requirements (e.g., lawn mowers, commercial light-duty vehicles, heavy-duty trucks, rail equipment, aircraft, waterborne vehicles)?

(3) Should one or more minimum emissions thresholds apply based on the mobile source category, and what would be appropriate annual thresholds?

(4) Are there certain categories of fleets that should be included or excluded from potential reporting requirements (e.g., public fleets versus private fleets)?

(5) If reporting requirements were to be introduced, what types of data should operators report (e.g., fuel consumption for estimating CO_2 and non-road N_2O and CH_4 emissions; mileage and vehicle technology for estimating on-road N_2O and CH_4 emissions; efficiency metrics such as emissions per tons carried)?

(6) What type of data verification or quality control should EPA require in any potential reporting requirements?

(7) For potential reporting requirements, are there preferred emissions quantification methods other than those presented in the SmartWay Freight Logistics Environmental and Energy Tracking model or the Climate Leaders reporting protocol?

VI. Collection, Management, and Dissemination of GHG Emissions Data

A. Purpose

This section of the preamble describes the process by which EPA proposes to collect, manage, and disseminate data under the GHG reporting rule.

Section V.B of this preamble describes the proposed establishment of a new reporting system that would accept electronic submissions of GHG emissions and supporting data, quality assure the submissions, store the results, and provide access to the public. The new system would follow Agency standards for design, security, data element and reporting format conformance, and accessibility.

Existing sources that would be affected by the proposed GHG reporting rule may currently report emissions or other data to the Agency (or in some cases States) under other titles of the CAA including Title I (Emission Inventory, SIP, NSPS and NESHAP), Title II (National Emissions Standards Act), Title IV (Acid Rain), Title V (Air Operating Permits) and Title VI (Stratospheric Ozone Protection). EPA intends to develop a reporting scheme that minimizes the burden of stakeholders by integrating the new reporting requirements with existing data collection and data management systems, when feasible. Also, EPA would work with States to ease the burden on reporters to State and Federal systems by harmonizing data management, where possible.

Section VI.B of this preamble further describes the proposal regarding the frequency and timeliness of reporting, the requirement for a Designated Representative certification, and the units of measure for submissions and published results.

Section VI.C of this preamble describes QA that EPA would perform to ensure the completeness, accuracy, and validity of submissions. It also describes the feedback that EPA would provide to emission reporters indicating the results of the electronic data quality checks.

Section VI.D of this preamble discusses publication of data that would be collected under the proposed

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[130] The SmartWay Freight Logistics Environmental and Energy Tracking model and accompanying user guide and glossary is available at *http://www.epa.gov/otaq/smartway/smartway_fleets_software.htm.*

[131] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA, 2007.

[132] See *Direct Emissions from Mobile Combustion Sources and Direct HFC and PFC Emissions from Use of Refrigeration and Air Conditioning Equipment*, available at *http://www.epa.gov/climateleaders/resources/cross-sector.html.*

[133] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA, 2007.

[134] A ''Class I railroad'' is defined as a carrier that has an annual operating revenue of $250 million or more after applying the railroad revenue deflator formula, which is based on the Railroad Freight Price Index developed by the U.S. Department of Labor, BLS. The formula is the current year's revenues x 1991 average index/current year's average index.

[135] The definition of ''large certified air carrier'',''small certified air carrier'', and ''commuter air carrier'' for Form 41 reporting requirements is available at: *http://www.bts.gov/programs/statistical_policy_and_research/source_and_accuracy_compendium/form41_schedule.html.*

mandatory GHG reporting rule. EPA proposes to make data collected under this rule available to State agencies and the public, with the exception of any CBI data, as discussed in Section I.C of this preamble. EPA requests comments on proposed strategies regarding data collection, management, and dissemination outlined in this section of the preamble.

B. Data Collection

1. Data Collection Methods

If a reporting source already reports GHG emissions data to an existing EPA program, the Agency would make efforts to minimize any additional burden on the sources. Some existing programs, however, have data collection and reporting requirements that are inconsistent with the proposed requirements for the mandatory GHG reporting rule. When it is not feasible to adapt the existing program to collect the appropriate emissions data and supplemental data, EPA proposes to require affected sources to submit the data in the requested format to the new data reporting system for the mandatory GHG reporting rule.

Emission sources may fall into one or more categories:

(1) Reporting sources that use existing data collection and reporting methods and would not be required to report separately to the new data reporting system for the GHG reporting rule.

(2) Reporting sources that use existing data collection and reporting methods but would be required to report the data separately to the new data reporting system for the GHG reporting rule.

(3) Reporting sources that are not currently required to collect and report GHG emissions data to EPA and would be required to report using the new data reporting system for the mandatory GHG reporting rule.

EPA believes that using existing data collection methods and reporting systems, when feasible, to collect data required by this proposed rule would minimize additional burden on sources and the Agency. We seek comment on the use of existing collection methods and reporting systems to collect information required by this proposed rule.

For those sources that do not report GHGs or data used to calculate GHG emissions through an existing reporting system, EPA proposes to develop a new system for emission reporters to submit the required data. The detailed data elements that would be reported and other requirements are specified in Sections III, IV and V of this preamble. In general, reporters using this new method would report annually to the Agency covering each calendar year by March 31 of the following year (e.g., annual emissions for calendar year 2010 would be reported by March 31, 2011.)

2. Data Submission

The Designated Representative (described in proposed 40 CFR part 98, subpart A and Section IV.G of this preamble) must use an electronic signature device (for example, a 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 propose that the new reporting system would 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.)

3. Unique Identifiers for Facilities and Units

We believe that 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 ORIS (DOE) ID code, and consistency from one reporting year to the next, we are proposing that the reporting system provide each facility with a unique identification code to be specified by the Administrator.

4. Reporting Emissions in a Single Unit of Measure

To maintain consistency with existing State-level and Federal-level greenhouse gas programs in the U.S. and internationally, the Agency is proposing that all emission measurements be 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 would be included in the data submission. All emissions data would be submitted to the agency in kg or metric tons per unit of time (per year in most cases, but for a few source categories emissions per hour, day, month, quarter, or other unit of time could also be required).

5. Conversion of Emissions to CO_2e

Under this proposed rule, reporters would submit the quantity of each applicable GHG emitted (or other metric) in two forms. The data would 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. Reporting the quantity and type of gas emitted allows for future recalculation of CO_2e emissions in the event that GWP factors change.

6. Delegation of Authority to State Agencies To Collect GHG Data

The Agency proposes that affected sources submit the emissions data and supplemental data directly to EPA. The Agency believes this would reduce the burden on reporters and State agencies, provide faster access to national emission data, and facilitate consistent QA.

Under CAA Section 114(b), EPA may delegate the authority to collect emissions data from stationary sources to State agencies provided the State agency can satisfy the procedural requirements. We seek comment on the possibility of delegating the authority to State agencies that request such authority and assessing whether the State agency has procedures that are deemed consistent and adequate with the procedures outlined in this rule. For example, how should EPA determine whether a requesting State agency has ‘‘consistent and adequate’’ procedures?

7. Submission Method

EPA proposes to require all sources affected by this rule to report in an electronic format to be specified by the Administrator. Advantages of electronic reporting include reduced burden on reporters and EPA staff, greater accuracy because data do not need to be manually entered by EPA staff, enhanced ability to conduct electronic audits to ensure data quality, improved comparability because data would be reported in a consistent format, and improved data availability for EPA and the public.

By not specifying the exact reporting format in the regulatory text, EPA maintains flexibility to modify the reporting format and tools in a timely manner. Changes based on stakeholder comment, implementation experience, and new technology could be executed without regulatory action. EPA has used this approach successfully with existing programs, such as the ARP and the Title VI Stratospheric Ozone Protection Program, facilitating the deployment of new reporting formats and tools that take advantage of technologies (e.g., XML) and reduce the burden on reporters and the Agency. The electronic reports submitted under this rule would also be subject to the provisions of 40 CFR 3.10, specifying EPA systems to which electronic submissions must be made and the requirements for valid electronic signatures.

C. Data Management

1. QA Procedures

The new reporting system would include automated checks for data completeness, data quality, and data consistency. Such automated checks are used for many other Agency programs (e.g., ARP).

2. 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. The process is largely dependent upon such factors as the type of data being submitted and the manner of data transmission. Regardless of data collection system specifics, the goal is to ensure appropriate transparency and timeliness when providing feedback to submitting entities.

D. Data Dissemination

1. Public Access to Emissions Data

The Agency proposes to publish data submitted or collected under this rulemaking through EPA's Web site, reports, and other formats, with the exception of any CBI data, as discussed in Section I.C of this preamble. This level of transparency would inform the public and facilitate greater data verification and review. Transparency helps to ensure data quality and build public confidence in the data so the data can be used to support the development of potential future climate policies or programs.

EPA proposes to disseminate the data on an annual basis. Under this proposed rule, affected sources would be required to report at least on an annual basis, with some reporting more frequently to existing data reporting programs (e.g., the ARP). The Agency believes it would be appropriate to post or publish data collected under this rule once a year after the reporting deadline. The Agency recognizes the high level of public interest in this data, and proposes to disclose it in a timely manner, while also assuring accuracy.

2. 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. These programs would likely still continue because they may be broader in scope or more aggressive in implementation than this proposal. In order to be consistent with and supportive of these programs and to reduce burden on reporters and program agencies, EPA proposes that it share emission data with the exception of any CBI data, as discussed in Section III.C of this preamble, with relevant agencies or approved entities using, where practical, shared tools and infrastructure.

VII. Compliance and Enforcement

A. Compliance Assistance

To facilitate implementation and compliance, EPA plans to conduct an active outreach and technical assistance program following publication of the final rule. The primary audience would be potentially affected industries. We intend to develop implementation and outreach materials to help facilities understand if the rule applies to them and explain the reporting requirements and timetables. The program particularly would target industrial, commercial, and institutional sectors that do not routinely deal with air pollution regulations.

Compliance materials could be tailored to the needs of various sectors. These materials might include, for example, compliance guides, brochures, fact sheets, frequently asked question and answer documents, sample reporting forms, and GHG emissions calculating tools. We also are considering a compliance assistance hotline for answering questions and providing technical assistance. (We may also want to consider creating a compliance assistance center (*http://www.assistancecenters.net*).) EPA requests comment on the types of assistance needed and the most effective mechanisms for delivering this assistance to various industry sectors.

B. Role of the States

State and local air pollution control agencies routinely interact with many of the sources that would report under this rule. Further, as mentioned in Section II of this preamble, many States have already implemented or are in the process of implementing mandatory GHG reporting and reduction programs. In fact, many States may have reporting programs that are broader in scope or more aggressive in implementation because those programs are either components of established reduction programs (e.g., cap and trade) or being used to design and inform specific complementary measures (e.g., energy efficiency).

Therefore, State and local agencies will serve an important 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 also can assist with educating facilities and assuring compliance at facilities subject to this rule.

As discussed in Section VI of this preamble, CAA section 114(b) 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 to State and local agencies. Even without delegation, EPA will work with States to ease burden on reporters to State and Federal systems by harmonizing data management, where possible. Further, as discussed in Section VI of this preamble, EPA is proposing to make the data collected under this rule available to States and other interested parties as soon as possible. For example, the quarterly data reported to EPA under Title IV of the CAA is often available on EPA's Web site within a month after it is reported. Furthermore, we recognize that many States with mandatory reporting programs are members of TCR. In some cases, TCR would provide States support in reporting tools, database management and serve as the ultimate repository for data reported under State programs, after the States have verified the data. Given the leadership many of the States have shown in developing and implementing GHG reporting and reduction programs, EPA is seeking comment on the possibility of delegating the authority to collect data under this rule to State agencies. Overall, we request comments on the role of States in implementing this rule and on how States and EPA could interact in administering the reporting program.

C. Enforcement

Facilities that fail to report GHG emissions according to the requirements of the proposed rule 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 $32,500 per day.[136]

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[136] The Federal Civil Penalties Inflation Adjustment Act of 1990, Public Law 101–410, 104

Continued

Deviations from the rule that could ultimately be considered violations include but are not limited to the following:

- Failure to report GHG emissions.
- Failure to collect data needed to estimate 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 keep records needed to verify GHG emissions estimates.
- Failure to estimate GHG emissions according to the methodology(s) specified in the rule.
- Falsification of reports.

VIII. Economic Impacts of the Proposed Rule

This section of the preamble examines the costs and economic impacts of the proposed rule, including the estimated costs and benefits of the proposed rule, and the estimated economic impacts of the proposed rule on affected entities, including estimated impacts on small entities. Complete detail of the economic impacts of the proposed rule can be found in the text of the regulatory impact analysis (RIA) (EPA–HQ–OAR–2008–0318–002).

A. How are compliance costs estimated?

EPA estimated costs of complying with the proposed rule for process emissions of GHGs in each affected industrial facility, as well as emissions from stationary combustion sources at industrial facilities and other facilities, and emissions of GHGs from 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 proposed rule would 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 proposed rule. For some affected 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 proposed 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 would 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 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 the 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 7 percent.

B. What are the costs of this proposed rule?

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. 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 proposed rule (to allow only the incremental costs to be estimated). Many of the affected sources 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 proposed rule to develop unique unit costs. This analysis is documented in the RIA. The TSDs for each source category provide a discussion of the applicable measurement technologies and any existing programs and practices. Section 4 of the RIA contains a description of the engineering cost analysis.

Table VIII–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 proposed rule. EPA estimates that the total national annualized cost for the first year is $168 million, and the total national annualized cost for subsequent years is $134 million (2006$). Of these costs, roughly 5 percent fall upon the public

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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 $32,500 per day of violation.

sector for program administration, while 95 percent fall upon the private sector. General stationary combustion sources, which are widely distributed throughout the economy, are estimated to incur approximately 18 percent of ongoing costs; other sectors incurring relatively large shares of costs are oil and natural gas systems (21 percent of ongoing costs), and iron and steel manufacturing (11 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 VIII–2 of this preamble provides the cost-effectiveness analysis for the various thresholds. Three 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. The third metric shown is the marginal cost of reported emissions. For this analysis, the marginal cost of reporting indicates the cost per metric ton of each threshold option relative to the 25,000 metric ton CO_2e proposed threshold). 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 and the RIA cost appendix. Not all subparts require capital expenditures but those that do are clearly documented in the RIA.

TABLE VIII–1. ESTIMATED COVERED ENTITIES, EMISSIONS AND COSTS BY SUBPART (2006$)

Subpart	Number of covered entities	Downstream emissions		First year capital costs		First year total annualized costs [2]	
		(Million of $MtCO_2e$)	Share (%)	(Million)	Share (%)	(Million)	Share (%)
Subpart A—General Provisions							
Subpart B—Reserved							
Subpart C—General Stationary Fuel Combustion Sources	3,000	220.0	6	$12.7	15	$29.0	17
Subpart D—Electricity Generation	1,108	2,262.0	58	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	0.4	0
Subpart G—Ammonia Manufacturing	24	14.5	0	0.0	0	0.4	0
Subpart H—Cement Production	107	86.8	2	5.4	6	6.9	4
Subpart I—Electronics Manufacturing	96	5.7	0	0.0	0	3.6	2
Subpart J—Ethanol Production	85	0.0	0	0.3	0	0.5	0
Subpart K—Ferroalloy Production	9	2.3	0	0.0	0	0.3	0
Subpart L—Fluorinated Gas Production	12	5.3	0	0.0	0	0.0	0
Subpart M—Food Processing	113	0.0	0	0.0	0	0.6	0
Subpart N—Glass Production	55	2.2	0	0.0	0	0.6	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	0.6	0
Subpart Q—Iron and Steel Production	121	85.0	2	0.0	0	18.2	11
Subpart R—Lead Production	13	0.8	0	0.0	0	0.3	0
Subpart S—Lime Manufacturing	89	25.4	1	4.9	6	5.3	3
Subpart T—Magnesium Production	11	2.9	0	0.0	0	0.1	0
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	0	0.9	1
Subpart W—Oil and Natural Gas Systems	1,375	129.9	3	37.8	43	32.5	19
Subpart X—Petrochemical Production	88	54.8	1	0.0	0	1.6	1
Subpart Y—Petroleum Refineries	150	204.7	5	1.6	2	3.7	2
Subpart Z—Phosphoric Acid Production	14	3.8	0	0.8	1	0.8	0
Subpart AA—Pulp and Paper Manufacturing	425	57.7	1	14.8	17	9.2	5
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	0.0	0
Subpart DD—Sulfur Hexafluoride (SF_6) from Electric Power Systems	141	10.3	0	0.0	0	0.4	0
Subpart EE—Titanium Dioxide Production	8	3.7	0	0.0	0	0.1	0
Subpart FF—Underground Coal Mines	100	33.5	1	0.6	1	2.3	1
Subpart GG—Zinc Production	5	0.8	0	0.0	0	0.1	0
Subpart HH—Landfills	2,551	91.1	2	7.9	9	15.3	9
Subpart II—Wastewater	0	0.0	0	0.0	0	0.0	0
Subpart JJ—Manure Management	43	1.5	0	0.0	0	0.2	0
Subpart KK—Suppliers of Coal and Coal-based Products & Subpart LL—Suppliers of Coal-based Liquid Fuels	1,237	(1)	0	0.0	0	11.0	7
Subpart MM—Suppliers of Petroleum Products	214	(1)	0	0.0	0	2.0	1
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	1,554	(1)	0	0.0	0	2.1	1
Subpart OO—Suppliers of Industrial Greenhouse Gases	121	464.1	12	0.0	0	0.4	0

TABLE VIII–1. ESTIMATED COVERED ENTITIES, EMISSIONS AND COSTS BY SUBPART (2006$)—Continued

Subpart	Number of covered entities	Downstream emissions		First year capital costs		First year total annualized costs[2]	
		(Million of $MtCO_2e$)	Share (%)	(Million)	Share (%)	(Million)	Share (%)
Subpart PP—Suppliers of Carbon Dioxide (CO_2)	13	(1)	0	0.0	0	0.0	0
Subpart QQ—Motor Vehicle and Engine Manufacturers	350	35.4	1	0.0	0	7.4	4
Private Sector, Total	13,205	3,869.9	100	87.1	100	160.4	95
Public Sector, Total	NA	NA	NA	NA	NA	8.0	5
Total	13,205	3,869.9	100	87.1	100	168.4	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 RIA section 4).

TABLE VIII–2. THRESHOLD COST-EFFECTIVENESS ANALYSIS (2006$)

Threshold (metric tons CO_2e)	Entities (covered)	Total costs (million $)	Million metric tons CO_2e/year (covered)	Percentage of total emissions reported	Average cost ($/metric ton)	Incremental cost ($/metric ton)	Marginal cost* ($/metric ton)
100,000	6,598	$101	3,699	52	$0.03	—	−$0.35
25,000	13,205	160	3,870	55	0.04	$0.35	—
10,000	20,765	213	3,916	56	0.05	1.16	1.16
1,000	59,587	426	3,951	56	0.11	6.09	3.29

*Cost per metric ton relative to the selected option.

Table VIII–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., coal mines, refineries, etc.) are also direct emitters of GHGs and are included in the downstream side of the table. As shown in Table VIII–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 VIII–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[3,10] (%)	First year cost[3] (millions)
Coal Supply	1,237	100.0	$11.03	Coal[5,6] Combustion	N/A	99.0	N/A
Petroleum Supply	214	100.0	1.99	Petroleum[5] Combustion[10]	N/A	20.0	N/A
Natural Gas Supply	1,554	68.0	2.14	Natural Gas[5] Combustion	N/A	23.0	N/A
				Sub Total Combustion	4,108	[5] N/A	46.16
Industrial Gas Supply	133	99.91	0.41	Industrial Gas Consumption.	265	28.0	3.70
				Industrial Processes	1,077	99.6	36.12
				Fugitive Emissions (coal, oil and gas).	1,475	86.6	34.86
				Biological Processes	2,792	55.5	16.59
				Vehicle[7] and Engine Manufacturers[9].	350	84.0	7.41

Notes:

[1] Most upstream facilities (e.g., coal mines, refineries, etc.) 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 proposed 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 Acid Rain Program.

[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 would 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 vehicle and engine manufacturers covered by this proposal rather than emissions coverage. This rule proposes to collect an emissions rate for the four ''transportation-related'' GHG emissions (CO_2, CH_4, N_2O and HFCs). The amounts of CH_4 and N_2O are dependent on factors other than fuel characteristics such as combustion temperatures, air-fuel mixes, and use of pollution control equipment.

[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 1 percent of the total emissions.

[11] EPA estimates that the majority of the costs for manufacturers of vehicles and engines can be attributed to the reporting requirements for non-CO_2 gases.

C. What are the economic impacts of the proposed rule?

EPA prepared an economic impact analysis to evaluate the impacts of the proposed 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 proposed rule.

To estimate the economic impacts of the proposed 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 are 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 proposed 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 proposed rule, rather than modeling market responses and using the resulting measures of social cost. Table VIII–4 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE VIII–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]
211	Oil & gas extraction	$23	0.1%
212	Mining (except oil & gas)	10	0.1
221	Utilities	1	<0.1
322	Paper mfg	22	0.1
324	Petroleum & coal products mfg	16	<0.1
325	Chemical mfg	12	<0.1
327	Nonmetallic mineral product mfg	51	0.8
331	Primary metal mfg	112	0.4
334	Computer & electronic product mfg	37	0.1
335	Electrical equipment, appliance, & component mfg	37	0.2
486	Pipeline transportation	12	0.1
562	Waste management & remediation services	6	0.2
325199	All other basic organic chemical mfg	24	<0.1
325311	Nitrogenous fertilizer mfg	19	0.1
327310	Cement mfg	65	0.2
331112	Electrometallurgical ferroalloy product mfg	28	<0.1
3272	Glass & glass product mfg	11	0.1
325120	Industrial gas mfg	3	<0.1
331112	Electrometallurgical ferroalloy product mfg	150	0.3
3314	Nonferrous metal (except aluminum) production & processing	23	0.1
327410	Lime mfg	60	0.4
325311	Nitrogenous fertilizer mfg	20	0.1
324110	Petroleum refineries	19	<0.1
325312	Phosphatic fertilizer mfg	60	0.1
322110	Pulp mills	22	<0.1
324110	Petroleum refineries	24	<0.1

TABLE VIII–4. ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES—Continued

NAICS	NAICS description	Average cost per entity ($1,000/entity)	Average entity cost-to-sales ratio [1]
327910	Abrasive product mfg	11	0.1
3251	Basic chemical mfg	9	<0.1
325188	All other basic inorganic chemical mfg	9	<0.1
3314	Nonferrous metal (except aluminum) production & processing	19	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.

D. What are the impacts of the proposed rule on small entities?

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

EPA believes the proposed thresholds maximize the rule coverage with 85 to 90 percent of U.S. GHG emissions reported by approximately 13,205 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 captured by the rule, EPA has proposed simplified emission estimation methods where feasible (e.g., stationary combustion equipment under a certain rating can use a simplified mass balance approach as opposed to more rigorous direct monitoring) to keep the burden of reporting as low as possible. For further detail on the rationale for excluding small entities through threshold selection please see the Thresholds TSD (EPA–HQ–OAR–2008–0508–046).

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 proposed rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., 1 percent or 3 percent).[137] 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 VIII–5 of this preamble.

TABLE VIII–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 (%)	Owned by enterprises with:					
						<20 Employees [f]	20 to 99 Employees (%)	100 to 499 Employees (%)	500 to 749 Employees (%)	750 to 999 Employees (%)	1,000 to 1,499 Employees (%)
Oil and Gas Extraction.	211	Oil & gas extraction	500	$23	0.1	1.5	0.1	0.1	0.0	0.0	0.0
Petroleum and Coal Products.	212	Mining (except oil & gas).	500	10	0.1	0.9	0.2	0.1	0.1	0.1	0.1
SF6 from Electrical Systems.	221	Utilities	([b])	1	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Pulp & Paper Manufacturing.	322	Paper mfg	500 to 750	22	0.1	1.3	0.3	0.1	0.1	0.0	0.0
Petroleum and Coal Products.	324	Petroleum & coal products mfg.	([c])	16	0.0	0.4	0.1	0.1	0.0	0.1	0.0
Chemical Manufacturing.	325	Chemical mfg	500 to 1,000	12	0.0	0.6	0.1	0.0	0.0	0.0	0.0
Cement & Other Mineral Production.	327	Nonmetallic mineral product mfg.	500 to 1,000	51	0.8	4.9	1.0	0.5	0.4	0.6	0.4
Primary Metal Manufacturing.	331	Primary metal mfg	500 to 1,000	112	0.4	9.1	1.4	0.4	0.2	0.1	0.2
Computer and Electronic Product Manufacturing.	334	Computer & electronic product mfg.	500 to 1,000	37	0.1	2.9	0.5	0.1	0.1	0.1	0.1
Electrical Equipment, Appliance, and Component Manufacturing.	335	Electrical equipment, appliance, & component mfg.	500 to 1,000	37	0.2	2.9	0.5	0.2	0.1	0.1	0.1
Oil & Natural Gas Transportation.	486	Pipeline transportation.	([d])	12	0.1	0.1	0.4	0.4	NA	NA	NA

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[137] EPA's RFA guidance for rule writers suggests the ''sales'' test continues to be the preferred quantitative metric for economic impact screening analysis.

TABLE VIII–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 (%)	Owned by enterprises with:					
						<20 Employees [f]	20 to 99 Employees (%)	100 to 499 Employees (%)	500 to 749 Employees (%)	750 to 999 Employees (%)	1,000 to 1,499 Employees (%)
Waste Management and Remediation Services.	562	Waste management & remediation services.	(e)	6	0.2	0.9	0.1	0.1	0.1	0.0	0.1
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	19	0.1	1.0	0.6	NA	NA	NA	NA
Cement	327310	Cement mfg	750	65	0.2	2.1	1.6	0.3	NA	NA	0.1
Ferroalloys	331112	Electrometallurgical ferroalloy product mfg.	750	28	0.0	NA	NA	NA	NA	NA	NA
Glass	3272	Glass & glass product mfg.	500 to 1,000	11	0.1	1.7	0.2	0.1	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
Iron and Steel	331112	Electrometallurgical ferroalloy product mfg.	750	150	0.3	NA	NA	NA	NA	NA	NA
Lead Production	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	23	0.1	1.5	0.2	0.1	NA	NA	0.1
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)	19	0.0	0.3	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	22	0.0	1.5	NA	NA	NA	NA	NA
Refineries	324110	Petroleum refineries.	(c)	24	0.0	0.4	0.0	0.0	0.0	NA	NA
Silicon Carbide	327910	Abrasive product mfg.	500	11	0.1	0.8	0.2	0.1	NA	NA	NA
Soda Ash Manufacturing.	3251	Basic chemical mfg	500 to 1,000	9	0.0	0.3	0.1	0.0	0.0	0.0	0.0
Titanium Dioxide	325188	All other basic inorganic chemical mfg.	1,000	9	0.0	0.7	0.4	0.1	NA	NA	NA
Zinc Production	3314	Nonferrous metal (except aluminum) production & processing.	750 to 1,000	19	0.1	1.2	0.1	0.1	NA	NA	0.1

[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 4 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 SUSB (SBA, 2008a) data does 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 $0.2 million with an average cost per ton reported of $0.14.

As shown, the cost-to-sales ratios are less than 1 percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (*e.g.* establishments owned by businesses with 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 would be covered by the rule, we performed several case studies for manufacturing industries where the cost-to-receipt ratio exceeded 1 percent. For each industry, we used and applied emission data from a recent study examining emission thresholds.[138] 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 1 percent.

For the other enterprise categories identified with ratios between 1 percent and 3 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 would not have a significant economic impact on a substantial number of small entities, the Agency nonetheless tried to reduce the impact of this rule on small entities, including seeking input from a wide range of private- and public-sector stakeholders. When developing the proposed 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 1 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 proposed 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 proposed 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 $17,047 per local government. Thus, for the smallest group of local governments (<10,000 people), cost-to-revenue ratio would be 0.8 percent. For the larger group of governments less than 50,000, the cost-to-revenue ratio is 0.3 percent.

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

EPA examined the potential benefits of the GHG reporting rule. Because the benefits of a reporting system are based on their relevance to policy making, transparency issues, and market efficiency, and therefore benefits would be 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 would 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 would 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 would 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. 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 would 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 would also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

IX. 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

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[138] 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.*

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–2008–0508–002 and is briefly summarized in Section VIII of this preamble.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by EPA has been assigned EPA ICR number 2300.01.

EPA plans to collect complete and accurate economy-wide data on facility-level greenhouse gas emissions. Accurate and timely information on greenhouse gas 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 greenhouse gas 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 information collected under CAA sections 114 and 208 cannot be claimed as CBI and will be made public.

The projected cost and hour burden for non-federal respondents is $143 million and 1.63 million hours per year. The estimated average burden per response is 2 hours; the proposed frequency of response is annual for all respondents that must comply with the proposed 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 18,775. 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 $20.7 million), a total operation and maintenance component (averaging $22.4 million per year), and a labor cost component (averaging $100.0 million per year). Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the RIA for several reasons:

- ICR costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the RIA for the first year of the rule and for subsequent years of the rule;
- The costs of reporting electricity purchases have been excluded from the ICR, but are still reported in the RIA, although electricity use reporting has been removed from the proposed rule and EPA is soliciting comment on it (see Section 4.2.2, pg 4–18); and
- The first-year costs of coverage determination, estimated to be $867.60 per facility for approximately 16,800 facilities that ultimately determine they do not have to report, are included in the ICR but not in the RIA (see Section 4.2.2, pg 4–18). These costs, averaged over 3 years, are $4.87 million incurred by an average of 5,613 respondents per year.

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. To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, EPA has established a public docket for this rule. Submit any comments related to the ICR to EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after April 10, 2009, a comment to OMB is best assured of having its full effect if OMB receives it by May 11, 2009. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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 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 proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this proposed 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, or because they have stationary combustion units onsite that emit GHGs that must be reported. Small governments and small non-profits are generally affected because they have regulated landfills or stationary combustion units onsite, or because they own a 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 proposed rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., 1 percent or 3 percent). The cost-to-sales ratios were constructed at the establishment level (average compliance cost for the establishment/average establishment revenues). As shown in Table VIII–5 of this preamble, the cost-to-sales ratios are less than 1 percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program.[139]

The screening analysis thus indicates that the proposed rule will not have a significant economic impact on a substantial number of small entities. See Table VIII–4 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 1 percent of average revenues for the smallest category of governments (those with fewer than 10,000 people).

Although this proposed 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, 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 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. EPA maintains an ''open door'' policy for stakeholders to provide input on key issues and to help inform EPA's understanding of issues, including thresholds for reporting and greenhouse gas calculation and reporting methodologies.

EPA continues to be interested in the potential impacts of the proposed rule on small entities and welcomes comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the UMRA 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, biologic and fugitive). 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 $14.1 million per year, based on average costs over the first three years of the rule. 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 air pollution control agencies, and other State and local government organizations. EPA contacted several States and State and regional organizations already involved in greenhouse gas emissions reporting. EPA also conducted several conference calls with Tribal organizations. 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 meeting and conference calls with groups such as TRI, 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.

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 proposed GHG reporting rule, and has concluded that the costs will fall mainly on the private sector (approximately $131 million), with some costs incurred by State, local, and Tribal governments that must report their emissions (less than $12.4 million) that own and operate stationary combustion units, landfills, or natural gas local distribution companies (LDCs). EPA estimates that an additional 1,979 facilities owned by state, local, or tribal governments will incur approximately $1.7 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 proposed 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 $145 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% of company sales in affected industries. These costs are broadly distributed to a variety of economic sectors and represent approximately 0.001 percent of 2007 Gross Domestic Product; overall, EPA does not believe the proposed rule will have a significant macroeconomic

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[139] 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.*

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 proposed rulemaking. EPA further expects that benefits of the proposed rule will include more and better information for EPA and the private sector about emissions of GHGs. This improved information would 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, 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 greenhouse gases above threshold levels such as a landfill or large stationary combustion source. 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 proposed 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 proposal relates to existing State programs, please see Section II of this preamble.

This regulation applies directly to facilities that supply fuel or chemicals that when used emit greenhouse gases or facilities that directly emit greenhouses gases. It does not apply to governmental entities unless the government entity owns a facility that directly emits greenhouse gases above threshold levels such as a landfill or large stationary combustion source, so relatively few government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this 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 solicits comments on this proposed rule from State and local officials.

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

This proposed rule is not expected to 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 greenhouse gases or facilities that directly emit greenhouses gases. Facilities expected to be affected by the proposed rule are not expected to be owned by Tribal governments. Thus, Executive Order 13175 does not apply to this proposed rule.

Although EO 13175 does not apply to this proposed 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. 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 specifically solicits additional comment on this proposed rule from Tribal officials.

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 proposed 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 proposal relates to monitoring, reporting and recordkeeping at facilities that supply fuel or chemicals that when used emit greenhouse gases 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 proposed rulemaking involves technical standards. EPA proposes to use more than 40 voluntary consensus standards from six different voluntary consensus standards bodies: ASTM, ASME, ISO, Gas Processors Association, American Gas Association, and American Petroleum Institute. These voluntary consensus standards will help facilities monitor, report, and keep records of greenhouse gas emissions. No new test methods were developed for this proposed rule. Instead, from existing rules for source categories and voluntary greenhouse gas programs, EPA identified existing means of monitoring, reporting, and keeping records of greenhouse gas 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 proposed rule and are available as specified in proposed 40 CFR 98.7.

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

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

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

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 proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This proposed 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.

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 600

Administrative practice and procedure, Electric power, Fuel economy, Incorporation by reference, Labeling, 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: March 10, 2009.

Lisa P. Jackson,

Administrator.

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

PART 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) Starting in the 2011 model year for heavy-duty engines, measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Report these values in your application for certification. 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/kW-hr.

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

3. Section 86.078–3 is amended by removing the paragraph (a) designation 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 B—[Amended]

4. A new § 86.165–11 is added to read as follows:

§ 86.165–11 Air Conditioning Idle Test Procedure.

(a) *Applicability.* This section describes procedures for determining air conditioning-related CO_2 emissions from 2012 and later model year light-duty vehicles, light-duty trucks, and medium-duty passenger vehicles.

(b) *Overview.* The test consists of a brief period to stabilize the vehicle at idle, followed by a ten-minute period of idle when CO_2 emissions are measured without any climate control systems operating; the test concludes with a ten-minute period when CO_2 emissions are measured with the air conditioning system operating. This test is designed to determine the air conditioning-related CO_2 emission value, in grams per minute per cubic foot of interior volume. If engine stalling occurs during cycle operation, follow the provisions of § 86.136–90 to restart the test. Measurement instruments must meet the specifications described in 40 CFR part 1065, subparts C and D.

(c) *Test sequence.* Before testing, precondition the vehicle as described in § 86.132, then allow the vehicle to idle for not less than 1 minute and not more than 5 minutes.

(1) Connect the vehicle exhaust system to the raw sampling location or dilution stage according to 40 CFR 1065.130. For dilution systems, dilute the exhaust as described in 40 CFR 1065.140. Continuous sampling systems must meet the specifications of 40 CFR 1065.145.

(2) Test the vehicle in a fully warmed-up condition. If the vehicle has soaked for two hours or less since the last exhaust test element, preconditioning may consist of a 505, 866, highway, US06, or SC03 test cycle. For longer soak periods, precondition the vehicle using one full Urban Dynamometer Driving Schedule.

(3) Immediately after the preconditioning described in paragraph (c)(1) of this section, turn off any cooling fans, if present, close the vehicle's hood, fully close all the vehicle's windows, ensure that all the vehicle's climate control systems are set to full off, start the CO_2 sampling system, and then idle the vehicle for not less than 1 minute and not more than 5 minutes to achieve normal and stable idle operation.

(4) Measure and record the continuous CO_2 concentration for 10.0 minutes. Measure the CO_2 concentration continuously using raw or dilute sampling procedures. Multiply this concentration by the continuous (raw or dilute) flow rate at the emission sampling location to determine the CO_2 flow rate. Calculate the constituent's cumulative flow rate continuously over the test interval. This cumulative value is the total mass of the emitted constituent.

(5) Within 60 seconds after completing the measurement described in paragraph (c)(4) of this section, turn on the vehicle's air conditioning system. Set automatic systems to a temperature 9 °F (5 °C) below the ambient temperature of the test cell. Set manual systems to maximum cooling with recirculation turned off. Continue idling the vehicle while measuring and recording the continuous CO_2 concentration for 10.0 minutes as described in paragraph (c)(4) of this section.

(d) *Calculations.* (1) For the measurement with no air conditioning, calculate the CO_2 emissions (in grams per minute) by dividing the total mass of CO_2 from paragraph (c)(4) of this section by 10.0.

(2) For the measurement with air conditioning in operation, calculate the CO_2 emissions (in grams per minute) by dividing the total mass of CO_2 from paragraph (c)(5) of this section by 10.0.

(3) Calculate the increased CO_2 emissions due to air conditioning (in grams per minute) by subtracting the results of paragraph (d)(1) of this section from the results of paragraph (d)(2) of this section.

(4) Divide the value from paragraph (d)(3) of this section by the interior volume of the vehicle to determine the increase in CO_2 emissions in grams per minute per cubic foot.

(e) *Reporting.* Include the value calculated in paragraph (d)(4) of this section in your application for certification.

Subpart E—[Amended]

5. 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.

* * * * *

6. Section 86.431–78 is amended by adding paragraph (e) to read as follows:

§ 86.431–78 Data submission.

* * * * *

(e) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 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 procedures specified in 40 CFR part 1065 as needed to measure N_2O, and CH_4. Report these values in your application for certification. Small-volume manufacturers (as defined in § 86.410–2006(e)) may omit this requirement. 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 0.001g/km.

Subpart S—[Amended]

7. Section 86.1804–01 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 86.1804–01 Acronyms and abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

8. Section 86.1843–01 is amended by adding paragraph (i) to read as follows:

§ 86.1843–01 General information requirements.

* * * * *

(i) *Air conditioning leakage reporting.* Starting in the 2011 model year, the manufacturer shall calculate and report a value for the annual leakage of refrigerant emissions from the air conditioning system for each model type as described in 40 CFR 1064.201. The manufacturer shall also report the type of refrigerant and the refrigerant capacity for each air conditioning system for each model type. The manufacturer shall calculate and report these items for each combination of vehicle model type (as defined in 40 CFR 600.002) and air conditioning system produced. However, calculation and reporting of these items for multiple air conditioning systems for a given model type is not necessary if air conditioning systems are identical with respect to the characteristics identified in paragraphs (i)(1) through (8) of this section and they meet the quantitative criteria identified in paragraph (i)(9) of this section. Consider all the following criteria to determine whether to calculate separate leakage rates for different air conditioning systems.

(1) Compressor type (e.g., belt driven or electric).

(2) Number and type of rigid pipes and method of connecting sections of rigid pipes.

(3) Number and type of flexible hose and method of connecting sections of flexible hose. Consider two hoses to be of a different type if they use different materials or if they have a different configuration of layers for reducing permeation.

(4) Number of high-side service ports.

(5) Number of low-side service ports.

(6) Number and type of switches, transducers, and expansion valves.

(7) Number and type of refrigerant control devices.

(8) Number and type of heat exchangers, mufflers, receiver/driers, and accumulators.

(9) The following quantitative criteria (based on nominal values) define operating characteristics for including air conditioning systems together:

(i) Refrigerant mass (rated capacity) of larger system divided by refrigerant mass of smaller system at or below 1.1.

(ii) Total length of rigid pipe in the longer system divided by total length of rigid pipe in the shorter system at or below 1.1.

(iii) Total length of flexible hose in the longer system divided by total length of flexible hose in the shorter system at or below 1.1.

9. Section 86.1844–01 is amended by adding paragraph (j) to read as follows:

§ 86.1844–01 Information requirements: Application for certification and submittal of information upon request.

* * * * *

(j) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 with each certification test on an emission data vehicle. Do not apply deterioration factors to the results. Use the procedures specified in 40 CFR part 1065 as needed to measure N_2O, and CH_4. Report these values in your application for certification. Use the same measurement methods as for your other results to report a single 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/mi.

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

(3) Round CH_4 to the nearest 0.001g/mi.

PART 87—[AMENDED]

10. The authority citation for part 87 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

11. Section 87.2 is amended by adding the abbreviations CH_4 and CO_2 in alphanumeric order to read as follows:

§ 87.2 Acronyms and abbreviations.

* * * * *

CH_4 methane.

* * * * *

CO_2 carbon dioxide.

* * * * *

12. Section 87.64 is revised to read as follows:

§ 87.64 Sampling and analytical procedures for measuring gaseous exhaust emissions.

(a) The system and procedures for sampling and measurement of gaseous emissions shall be as specified by Appendices 3 and 5 to ICAO Annex 16 (incorporated by reference in § 87.8).

(b) Starting in the 2011 model year, measure CH_4 with each certification test. Use good engineering judgment to determine CH_4 emissions using a nonmethane cutter or gas chromatograph as described in 40 CFR 1065.265 and 1065.267. Report CH_4 and CO_2 values along with your emission levels of regulated pollutants. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kilonewton rO.

(2) Round CH_4 to the nearest 0.01g/g/kilonewton rO.

PART 89—[AMENDED]

13. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

14. Section 89.3 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 89.3 Acronyms and abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

Subpart B—[Amended]

15. Section 89.115 is amended by revising paragraph (d)(9) to read as follows:

§ 89.115 Application for certificate.

* * * * *

(d) * * *

(9) All test data obtained by the manufacturer on each test engine, including CO_2, N_2O, and CH_4 as specified in § 89.407(d)(1);

* * * * *

Subpart E—[Amended]

16. Section 89.407 is amended by revising paragraph (d)(1) to read as follows:

§ 89.407 Engine dynamometer test run.

* * * * *

(d) * * *

(1) Measure HC, CO, CO_2, and NO_X concentrations in the exhaust sample. Starting in the 2011 model year, also measure N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers (as defined in 40 CFR 1039.801) may omit N_2O, and CH_4 measurements. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2, N_2O, and CH_4. Round the final values as follows:

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

(ii) Round N_2O to the nearest 0.001 g/kW-hr.

(iii) Round CH_4 to the nearest 0.001g/kW-hr.

* * * * *

PART 90—[AMENDED]

17. The authority citation for part 90 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

18. Section 90.5 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 90.5 Acronyms and abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

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Subpart B—[Amended]

19. Section 90.107 is amended by revising paragraph (d)(8) to read as follows:

§ 90.107 Application for certification.

* * * * *

(d) * * *

(8) All test data obtained by the manufacturer on each test engine, including CO_2, N_2O, and CH_4 as specified in § 90.409(c)(1);

* * * * *

Subpart E—[Amended]

20. Section 90.409 is amended by revising paragraph (c)(1) to read as follows:

§ 90.409 Engine dynamometer test run.

* * * * *

(c) * * *

(1) Measure HC, CO, CO_2, and NO_X concentrations in the exhaust sample. Starting in the 2011 model year, also measure N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit N_2O, and CH_4 measurements. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2, N_2O, and CH_4. Round the final values as follows:

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

(ii) Round N_2O to the nearest 0.001 g/kW-hr.

(iii) Round CH_4 to the nearest 0.001g/kW-hr.

* * * * *

PART 94—[AMENDED]

21. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

22. Section 94.3 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 94.3 Abbreviations.

* * * * *

* * * * *

CH_4 methane.

* * * * *

N_2O nitrous oxide.

* * * * *

Subpart B—[Amended]

22. Section 94.104 is amended by adding paragraph (e) to read as follows:

§ 94.104 Test procedures for Category 2 marine engines.

* * * * *

(e) Measure CO_2 as described in 40 CFR 92.129 through the 2010 model year. Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 as specified in 40 CFR 1042.235.

§ 94.109 [Amended]

23. Section 94.109 is amended by adding paragraph (d) to read as follows:

Subpart C—[Amended]

24. Section 94.203 is amended by revising paragraph (d)(10) to read as follows:

§ 94.203 Application for certification.

* * * * *

(d) * * *

(10) All test data obtained by the manufacturer on each test engine, including CO_2, N_2O, and CH_4 as specified in 40 CFR 89.407(d)(1) for Category 1 engines, § 94.104(e) for Category 2 engines, and § 94.109(d) for Category 3 engines. Small-volume manufacturers may omit the requirement to measure and report N_2O, and CH_4.

* * * * *

25. Add part 98 to read as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Sec.

Subpart A—General Provisions

Subpart B [Reserved]

Subpart C—General Stationary Fuel Combustion Sources

Subpart D—Electricity Generation

Subpart E—Adipic Acid Production

Subpart F—Aluminum Production

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98.93 Calculating GHG emissions.
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98.110 Definition of the source category.
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Subpart M—Food Processing

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Subpart N—Glass Production

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98.141 Reporting threshold.
98.142 GHGs to report.
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Subpart Y—Petroleum Refineries

98.250 Definition of source category.
98.251 Reporting threshold.

98.252 GHGs to report.
98.253 Calculating GHG emissions.
98.254 Monitoring and QA/QC requirements.
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Subpart Z—Phosphoric Acid Production

98.260 Definition of the source category.
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98.263 Calculating GHG emissions.
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Subpart AA—Pulp and Paper Manufacturing

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98.271 Reporting threshold.
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98.275 Procedures for estimating missing data.
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Table AA–1 of Subpart AA—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO_2, CH_4, and N_2O
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98.283 Calculating GHG emissions.
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98.285 Procedures for estimating missing data.
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Subpart CC—Soda Ash Manufacturing

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98.300 Definition of the source category.
98.301 Reporting threshold.
98.302 GHGs to report.
98.303 Calculating GHG emissions.
98.304 Monitoring and QA/QC requirements.
98.305 Procedures for estimating missing data.
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98.307 Records that must be retained.
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Subpart EE—Titanium Dioxide Production

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98.313 Calculating GHG emissions.
98.314 Monitoring and QA/QC requirements.
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98.323 Calculating GHG emissions.
98.324 Monitoring and QA/QC requirements.
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Subpart GG—Zinc Production

98.330 Definition of the source category.
98.331 Reporting threshold.
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98.333 Calculating GHG emissions.
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98.400 Definition of the source category.
98.401 Reporting threshold.
98.402 GHGs to report.
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Subpart OO—Suppliers of Industrial Greenhouse Gases

Subpart PP—Suppliers of Carbon Dioxide

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

Subpart A—General Provisions

§ 98.1 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) emissions reporting requirements for certain facilities that directly emit GHG as well as for fossil fuel suppliers and industrial GHG suppliers.

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of subpart A and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the subparts B through PP of this part shall take precedence.

§ 98.2 Do I need to report?

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements, of this part apply to the owners and operators of any facility that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any of the source categories listed in this paragraph in any calendar year starting in 2010. For these facilities, the GHG emission report must cover all sources in any source category for which calculation methodologies are provided in subparts B through JJ of this part.

(i) Electricity generating facilities that are subject to the Acid Rain Program, or that contain electric generating units that collectively emit 25,000 metric tons CO_2e or more per year.

(ii) Adipic acid production.

(iii) Aluminum production.

(iv) Ammonia manufacturing.

(v) Cement production.

(vi) Electronics—Semiconductor, microelectricomechanical system (MEMS), and liquid crystal display (LCD) manufacturing facilities with an annual production capacity that exceeds any of the thresholds listed in this paragraph.

(A) Semiconductors: 1,080 m^2 silicon.

(B) MEMS: 1,020 m^2 silicon.

(C) LCD: 235,700 m^2 LCD.

(vii) Electric power systems that include electrical equipment with a total nameplate capacity that exceeds 17,820 lbs (7,838 kg) of SF_6 or perfluorocarbons (PFCs).

(viii) HCFC–22 production.

(ix) HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year.

(x) Lime manufacturing.

(xi) Nitric acid production.

(xii) Petrochemical production.

(xiii) Petroleum refineries.

(xiv) Phosphoric acid production.

(xv) Silicon carbide production.

(xvi) Soda ash production.

(xvii) Titanium dioxide production.

(xviii) Underground coal mines that are subject to quarterly or more frequent sampling by MSHA of ventilation systems.

(xix) Municipal landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year.

(xx) Manure management systems that emit CH_4 and N_2O in amounts equivalent to 25,000 metric tons CO_2e or more per year.

(2) Any facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this paragraph (a)(2) and that are located at the facility in any calendar year starting in 2010. For these facilities, the GHG emission report must cover all source categories for which calculation methodologies are provided in subparts B through JJ of this part.

(i) Electricity generation.

(ii) Electronics—photovoltaic manufacturing.

(iii) Ethanol production.

(iv) Ferroalloy production.

(v) Fluorinated greenhouse gas production.

(vi) Food processing.

(vii) Glass production.

(viii) Hydrogen production.

(ix) Iron and steel production.

(x) Lead production.

(xi) Magnesium production.

(xii) Oil and natural gas systems.

(xiii) Pulp and Paper Manufacturing.

(xiv) Zinc production.

(xv) Industrial landfills.

(xvi) Wastewater treatment.

(3) Any facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the GHG emission report must cover emissions from stationary fuel combustion sources only. For 2010 only, the facilities may submit an abbreviated emissions report according to § 98.3(d).

(i) The facility does not contain any source category designated in paragraphs (a)(1) and (2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.

(iii) The facility emits 25,000 metric tons CO_2e or more per year from all stationary fuel combustion sources.

(4) Any supplier of any of the products listed in this paragraph (a)(4) in any calendar year starting in 2010. For these suppliers, the GHG emissions report must cover all applicable products for which calculation methodologies are provided in subparts KK through PP of this part.

(i) Coal.

(ii) Coal-based liquid fuels.

(iii) Petroleum products.

(iv) Natural gas and natural gas liquids.

(v) Industrial greenhouse gases, as specified in either paragraph (a)(4)(v)(A) or (B) of this section:

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse gases with total bulk imports that exceed 25,000 metric tons CO_2e per year.

(C) Exporters of industrial greenhouse gases with total bulk exports that exceed 25,000 metric tons CO_2e per year.

(vi) Carbon dioxide, as specified in either paragraph (a)(4)(vi)(A) or (B) of this section.

(A) All producers of carbon dioxide.

(B) Importers of CO_2 or a combination of CO_2 and other industrial GHGs with total bulk imports that exceed 25,000 metric tons CO_2e per year.

(C) Exporters of CO_2 or a combination of CO_2 and other industrial GHGs with total bulk exports that exceed 25,000 metric tons CO_2e per year.

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, and fluorinated GHG (as defined in § 98.6) in metric tons from stationary fuel combustion units, miscellaneous uses of carbonate, and any applicable source category listed in paragraph § 98.2(a)(2). The GHG emissions shall be calculated using the methodologies specified in each applicable subpart. For this calculation, facilities with industrial landfills must use the CH_4 generation calculation methodology in subpart HH of this part.

(2) For stationary combustion units, calculate the annual CO_2 emissions in metric tons using any appropriate method specified in § 98.33(a). Calculate the annual CH_4 and N_2O emissions from the stationary combustion sources in metric tons using Equation C–9 in § 98.33(c). Carbon dioxide emissions from the combustion of biogenic fuels shall be excluded from the calculations. In using Equations C–2a and C–9 in § 98.33, the high heat value for all types of fuel shall be determined monthly.

(3) For miscellaneous uses of carbonate, calculate the annual CO_2 emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (2), and (3) of this section for each GHG and calculate metric tons of CO_2e using Equation A–1.

$$CO_2e = \sum_{i=1}^{n} GHG_i \text{ x } GWP_i \qquad \text{(Eq. A-1)}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.
GWP_i = Global warming potential for each greenhouse gas from Table A–1 of this subpart.
n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, capture of CO_2 for transfer off site must not be considered.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, the owner or operator shall calculate CO_2, CH_4, N_2O emissions from all stationary combustion units using the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO_2e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold for importers and exporters of industrial greenhouse gases under paragraph (a)(4) of this section, the owner or operator shall calculate the total annual CO_2e of all the industrial GHGs that the company imported and the total annual CO_2e of all the industrial GHGs that the company exported during the reporting year, as described in paragraphs (d)(1) through (d)(3) of this section.

(1) Calculate the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG (as defined in § 98.6) imported and the mass in metric tons per year of CO_2, N_2O, and fluorinated GHG exported during the year. The masses shall be calculated using the methodologies specified in subpart OO of this part.

(2) Convert the mass of each GHG imported and each GHG exported from paragraph (d)(1) of this section to metric tons of CO_2e using Equation A–1 of § 98.3.

(3) Sum the total annual metric tons of CO_2e in paragraph (d)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO_2e in paragraph (d)(2) of this section for all exported GHGs.

(e) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records to determine whether the threshold has been exceeded.

(f) Except as provided in paragraph (g) of this section, the owners and operators of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section are not required to submit an emission report for the facility or supplier. Such owners and operators must reevaluate the applicability to this part to the facility or supplier (which reevaluation must include the revising of any relevant emissions calculations or other calculations) whenever there is any change to the facility or supplier that could cause the facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(g) Once a facility or supplier is subject to the requirements of this part, the owners and operators of the facility or supply operation must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit GHG emission reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year. If a GHG emission source in a future year through change of ownership becomes part of a different facility that has not previously met, and does not in that future year meet, the applicability requirements of paragraph (a) of this section; the owner or operator shall comply with the requirements of this part only with regard to that source, including the requirement to submit GHG emission reports.

(h) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

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

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG emissions reports to the Administrator, as specified in paragraphs (a) through (g) of this section.

(a) *General.* You must collect emissions data, calculate GHG emissions, and follow the procedures for quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) *Schedule.* Unless otherwise specified in subparts B through PP, you must submit an annual GHG emissions report no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For existing facilities that commenced operation before January 1, 2010, you must report emissions for calendar year 2010 and each subsequent calendar year.

(2) For new facilities that commence operation on or after January 1, 2010, you must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, you must report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(c) *Content of the annual report.* Except as provided in paragraph (d) of this section, each annual GHG emissions report shall contain the following information:

(1) Facility name or supplier name (as appropriate), street address, physical address, and Federal Registry System identification number.

(2) Year covered by the report.

(3) Date of submittal.

(4) Annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG. Emissions must be calculated assuming no capture of CO_2 and reported at the following levels:

(i) Total facility emissions aggregated from all applicable source categories in subparts C through JJ of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(ii) Total emissions aggregated from all applicable supply categories in subparts KK through PP of this part and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart.

(iii) Emissions from each applicable source category or supply category in subparts C through PP of this part, expressed in metric tons of each GHG.

(iv) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in the ''Data reporting requirements'' section of each applicable subpart of this part.

(5) Total electricity generated onsite in kilowatt hours.

(6) Total pounds of synthetic fertilizer produced at the facility and total nitrogen contained in that fertilizer.

(7) Total annual mass of CO_2 captured in metric tons.

(8) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(d) *Abbreviated emissions report.* In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that is subject to § 98.2(a)(3) may submit an abbreviated GHG emissions report for the facility for emissions in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report for a facility in 2011 must submit a full GHG emissions report according to the requirements of paragraph (c) of this section for each calendar year thereafter. The abbreviated facility report must include the following information:

(1) Facility name, street address, physical address, and Federal Registry System identification number.

(2) The year covered by the report.

(3) Date of submittal.

(4) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any appropriate method specified in § 98.33(a) and expressed in metric tons of CO_2, CH_4, N_2O, and CO_2e. If Equation C–2a or C–9 of subpart C are selected, the high heat value for all types of fuel shall be determined monthly.

(5) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(e) *Emission Calculations.* In preparing the GHG emissions report, you must use the emissions calculation protocols specified in the relevant subparts, except as specified in paragraph (d) of this section.

(f) *Verification.* To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(8) and (d)(5) of this section and any other credible evidence, in conjunction with a comprehensive review of the emissions reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) *Recordkeeping.* An owner or operator that is required to report GHG emissions under this part must keep records as specified in this paragraph. You must retain all required records for at least 5 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by EPA, the records required under this section must be made available to the Administrator. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. The results of all required fuel analyses for high heat value and carbon content, the results of all required certification and quality assurance tests of continuous monitoring systems and fuel flow meters if applicable, and analytical results for the development of site-specific emissions factors.

(3) Documentation of the process used to collect the necessary data for the GHG emissions calculations.

(4) The GHG emissions calculations and methods used.

(5) All emission factors used for the GHG emissions calculations.

(6) Any facility operating data or process information used for the GHG emission calculations.

(7) Names and documentation of key facility personnel involved in calculating and reporting the GHG emissions.

(8) The annual GHG emissions reports.

(9) A log book, documenting procedural changes (if any) to the GHG emissions accounting methods and changes (if any) to the instrumentation critical to GHG emissions calculations.

(10) Missing data computations.

(11) A written quality assurance performance plan (QAPP). Upon request from regulatory authorities, the owner or operator shall make all information that is collected in conformance with the QAPP available for review during an audit. Electronic storage of the information in the QAPP is permissible, provided that the information can be made available in hard copy upon request during an audit. At a minimum, the QAPP plan shall include (or refer to separate documents that contain) a detailed description of the procedures that are used for the following activities:

(i) Maintenance and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions reported under this part. A maintenance log shall be kept.

(ii) Calibrations and other quality assurance tests performed on the continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions reported under this part.

§ 98.4 Authorization and responsibilities of the designated representative.

(a) *General.* Except as provided under paragraph (f) of this section, each owner or operator that is subject to this part, shall have one and only one designated representative responsible for certifying and submitting GHG emissions reports and any other submissions to the Administrator under this part.

(b) *Authorization of a designated representative.* The designated representative of the facility shall be selected by an agreement binding on the owners and operators and shall act in accordance with the certification statements in paragraph (i)(4) of this section. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for enviromental matters for the company.

(c) *Responsibility of the designated representative.* Upon receipt by the Administrator of a complete certificate of representation under this section, the designated representative of the facility shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) *Timing.* No GHG emissions report or other submissions under this part will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the owner or operator.

(e) *Certification of the GHG emissions report.* Each GHG emission report and any other submission under this part shall be submitted, signed, and certified by the designated representative in accordance with 40 CFR 3.10.

(1) Each such submission shall include the following certification statement by the designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate) for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The Administrator will accept a GHG emission report or other submission under this part only if the submission is signed and certified in accordance with paragraph (e)(1) of this section.

(f) *Alternate designated representative.* A certificate of representation under this section may designate an alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section, any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term ''designated representative'' is used, the term shall be construed to include the designated representative or any alternate designated representative.

(g) *Changing a designated representative or alternate designated representative.* The designated representative (or alternate designated representative) may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative (or alternate designated representative) before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(h) *Changes in owners and operators.* In the event a new owner or operator is not included in the list of owners and operators in the certificate of representation under this section, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative, as if the new owner or operator were included in such list. Within 30 days following any change in the owners and operators, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under this section amending the list of owners and operators to include the change.

(i) *Certificate of representation.* A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the facility or supply operation for which the certificate of representation is submitted.

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

(3) A list of the owners and operators of the facility or supply operation.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators that are subject to the requirements of 40 CFR 98.3.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the Mandatory Greenhouse Gas Reporting Program on behalf of the owners and operators that are subject to the requirements of 40 CFR 98.3 and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators that are subject to the requirements of 40 CFR 98.3 shall be bound by any order issued to me by the Administrator or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a facility (or supply operation as appropriate) that is subject to the requirements of 40 CFR 98.3, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator that is subject to the requirements of 40 CFR 98.3.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) *Documents of Agreement.* Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) *Binding nature of the certificate of representation.* Once a complete certificate of representation under this section has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under this section is received by the Administrator.

(l) *Objections concerning a designated representative.* (1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under the Mandatory Greenhouse Gas Reporting Program.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

§ 98.5 How do I submit my report?

Each GHG emissions report for a facility or supplier must be submitted electronically on behalf of the owners and operators of that facility or supplier by their designated representative, in a format specified by the Administrator.

§ 98.6 What definitions do I need to understand?

All terms used in this part shall have the same meaning given in the Clean Air Act and in this section.

Abandoned (closed) mines mean mines that are no longer operational (per MSHA definition).

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Accuracy of a measurement at a specified level (e.g., one percent of full scale) means that the mean of repeat measurements made by a device or technique has a 95 percent chance of falling within the range bounded by the true value plus or minus the specified level.

Acid gas means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal process.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents, such as liquid absorbents, solid adsorbents, or membrane separators.

Acid gas removal vent stack fugitive emissions mean the acid gas (typically CO_2 and H_2S) separated from the acid gas absorbing medium (most commonly an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Acid Rain Program means the program established under title IV of the Clean Air Act, and implemented under parts 72 through 78 of this chapter for the reduction of sulfur dioxide and nitrogen oxides emissions.

Actual conditions mean temperature, pressure and volume at measurement conditions of natural gas.

Actuation means, for the purposes of this rule, an event in which a natural gas pneumatically driven valve is opened and/or closed by release of natural gas pressure to the atmosphere.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's authorized representative.

AGA means the American Gas Association

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content).

Alkali bypass means a duct between the feed end of the kiln and the preheater tower through which a portion of the kiln exit gas stream is withdrawn and quickly cooled by air or water to avoid excessive buildup of alkali, chloride and/or sulfur on the raw feed. This may also be referred to as the ''kiln exhaust gas bypass.''

Anaerobic digester means the equipment designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO_2 and CH_4, which is captured and flared or used as a fuel.

Anode effect is a process upset condition of an aluminum electrolysis cell caused by too little alumina dissolved in the electrolyte. The anode effect begins when the voltage rises rapidly and exceeds a threshold voltage, typically 8 volts.

Anode Effect Minutes Per Cell Day (24 hours) are the total minutes during which an electrolysis cell voltage is above the threshold voltage, typically 8 volts.

ANSI means the American National Standards Institute.

Anti-static wrap means wrap used to assist the process of ensuring that all fugitive emissions from a single source are captured and directed to a measurement instrument.

API means the American Petroleum Institute.

Argon-oxygen decarburization (AOD) vessel means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining to reduce the carbon content of the steel.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

B_0 means the maximum CH_4 producing capacity of a waste stream, kg CH_4/kg COD.

Backpressure means impeding the natural atmospheric release of fugitive emissions by enclosing the release with a lower capacity sampling device and altering natural flow.

Basic oxygen furnace means any refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel.

Biodiesel means any liquid biofuel suitable as a diesel fuel substitute or a diesel fuel additive or extender. Biodiesel fuels are usually made from agricultural oils or from animal tallow.

Biogenic CO_2 means carbon dioxide emissions generated as the result of biomass combustion.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Blast furnace means a furnace that is located at an integrated iron and steel plant and is used for the production of molten iron from iron ore pellets and other iron bearing materials.

Bleed rate means the rate at which natural gas flows continuously or intermittently from a process measurement instrument to a valve actuator controller where it is vented (bleeds) to the atmosphere.

Blendstocks are naphthas used for blending or compounding into finished motor gasoline. These include RBOB (reformulated gasoline for oxygenate blending), CBOB (conventional gasoline for oxygebate blending), and GTAB (gasoline treated as blendstock).

Blowdown means manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.

Blowdown vent stack fugitive emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and Emergency Shut-Down system testing.

Boil-off gas means natural gas that vaporizes from liquefied natural gas in storage tanks.

British Thermal Unit or Btu means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Bulk, with respect to industrial GHG suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Butane (*C_4H_{10}*) *or n-Butane* means the normally gaseous straight-chain or branch-chain hydrocarbon extracted from natural gas or refinery gas streams and is designated in ASTM Specification D1835 and Gas Processors Association Specifications for commercial butane. Not included in this definition is isobutene, which normally is used for feedstock.

Butylene (C_2H_8) is an olefinic hydrocarbon recovered from refinery processes and used as a feedstock.

By-product coke oven battery means a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas from which by-products are recovered.

By-product formation is the quantity of fluorinated GHGs created during the etching or chamber cleaning processes in an electronics manufacturing process.

C2+ means the NGL fraction consisting of hydrocarbon molecules ethane and heavier. The characteristics for this fraction, as reported in Table MM–2, are derived from the mixture of 31 percent ethane and 29 percent propane as reported in Table MM–1, and 41 percent C4+. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

C4+ means the NGL fraction consisting of hydrocarbon molecules butane and heavier. The characteristics for this fraction, as reported in Table MM–2, are derived from the mixture of 39 percent ‘‘pentanes plus’’ and 61 percent butane as reported in Table MM–1. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

C5+ is pentane plus in the specific chemical composition that underlies the default factors in Table MM–1.

C6+ means NGL fraction consisting of hydrocarbon molecules hexane and heavier. The characteristics for this fraction, as reported in Table MM–2, are derived from the assumption that ‘‘pentane plus’’, as reported in Table MM–1, consists of a mixture of 53 percent C6+ and 47 percent pentane. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

Calibrated bag means a flexible, non-elastic bag of a calibrated volume that can be quickly affixed to a fugitive emitting source such that the fugitive emissions inflate the bag to its calibrated volume.

Carbon black oil means a heavy aromatic oil that may be derived either as a by-product of petroleum refining or metallurgical coke production. Carbon black oil consists mainly of unsaturated hydrocarbons, predominately higher than C14.

Carbon dioxide equivalent or *CO_2e* means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another primary greenhouse gas.

Carbon dioxide production well means any hole drilled in the earth to extract a carbon dioxide stream from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide production well facility means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO_2 production well facility.

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g., a power plant or other industrial facility) or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

Carbon share means the weight percentage of carbon in any product.

Carbonate means compounds containing the radical CO_3^{-2}. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO_2). Common carbonates consumed in the mineral industry include calcium carbonate ($CaCO_3$) or calcite; magnesium carbonate ($MgCO_3$) or magnesite; and calcium-magnesium carbonate ($CaMg(CO_3)_2$) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: calcium carbonate ($CaCO_3$), calcium magnesium carbonate ($CaMg(CO_3)_2$), and sodium carbonate (Na_2CO_3).

Carbonate-based mineral mass fraction means the following: for limestone, the mass fraction of $CaCO_3$ in the limestone; for dolomite, the mass fraction of $CaMg(CO_3)_2$ in the dolomite; and for soda ash, the mass fraction of Na_2CO_3 in the soda ash.

Carbonate-based raw material means any of the following materials used in the manufacture of glass: limestone, dolomite, and soda ash.

Carrier gas means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO_2, N_2, and/or dry air.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

Cattle and swine deep bedding means as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.

CBOB or conventional gasoline for oxygenate blending means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional gasoline.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals fugitive emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seals mean a series of rings around the compressor shaft where it exits the compressor case, that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor wet seals fugitive emissions mean natural gas released from the seal face around the rotating shaft where it exits one or both ends of the compressor case PLUS the natural gas absorbed in the circulating seal oil and vented to the atmosphere from a seal oil degassing vessel or sump before the oil is re-circulated, or from a seal oil containment vessel vent.

Certified standards means calibration gases certified by the manufacturer of the calibration gases to be accurate to within 2 percent of the value on the label or calibration gases.

CH_4 means methane.

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

Chemical recovery furnace means an enclosed combustion device where concentrated spent liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes any recovery furnace that burns spent pulping liquor produced from both the kraft and soda pulping processes.

Chloride process means a production process where titanium dioxide is produced using calcined petroleum coke and chlorine as raw materials.

Close-range means, for the purposes of this rule, safely accessible within the operator's arm's reach from the ground or stationary platforms.

CO_2 means carbon dioxide.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 ''Standard Classification of Coals by Rank'' (as incorporated by reference in § 98.7).

COD means the chemical oxygen demand as determined using methods specified pursuant to 40 CFR Part 136.

Coke (petroleum) means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

Coke burn-off means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

Cokemaking means the production of coke from coal in either a by-product coke oven battery or a non-recovery coke oven battery.

Cold and steady emissions mean a nearly constant and steady emissions stream that is low enough in temperature (i.e., less than 140 degrees Fahrenheit) to be safely directly measured by a person.

Commercial Applications means any use including but not limited to: Food and beverage, industrial and municipal water/wastewater treatment, metal fabrication, including welding and cutting, greenhouse uses for plant growth, fumigants (e.g., grain storage) and herbicides, pulp and paper, cleaning and solvent use, fire fighting, transportation and storage of explosives, enhanced oil and natural gas recovery, long-term storage (sequestration), or research and development.

Completely destroyed means destroyed with a destruction efficiency of 99.99 percent or greater.

Completely recaptured means 99.99 percent or greater of each GHG is removed from a process stream.

Component, for the purposes of subpart W only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas (i.e., compression ratio higher than 1.5).

Compressor fugitive emissions mean natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

Connector means but is not limited to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, ''T's'' or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in North American Industry Classification System 327213 (NAICS 327213).

Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

Continuous glass melting furnace means a glass melting furnace that operates continuously except during periods of maintenance, malfunction, control device installation, reconstruction, or rebuilding.

Control method means any equipment used for recovering and/or oxidizing air emissions of methane. Such equipment includes, but is not limited to, vapor recovery systems, absorbers, carbon dioxide adsorbers, condensers, incinerators, flares, catalytic oxidizers, boilers, and process heaters.

Conventional gasoline means any gasoline which has not been certified under § 80.40.

Cover gas means SF_6, HFC–134a, fluorinated ketone (FK 5–1–12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that is the source of the casting operation.

Crude oil means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chains and rings.

Daily spread means manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

Degasification systems mean wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. Pre-mining degasification systems refer to drainage wells drilled through a coal seam or seams and cased to pre-drain the methane prior to mining. The wells are normally placed in operation 2 to 7 years ahead of mining. Degasification systems also include ‘‘gob wells’’ which recover methane from the longwall face area during and after mining.

Degradable organic carbon (DOC) means the fraction of the total mass of a waste material that can be biologically degraded.

Dehydrator means, for the purposes of this rule, a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent stack fugitive emissions means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

Delayed coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (ethane, propane, butane, pentane-plus) in feed natural gas stream.

Density means the mass contained in a given unit volume (mass/volume).

Destruction means, with respect to underground coal mines, the combustion of methane in any on-site or off-site combustion technology. Destroyed methane includes, but is not limited to, methane combusted by flaring, methane destroyed by thermal oxidation, methane combusted for use in on-site energy or heat production technologies, methane that is conveyed through pipelines (including natural gas pipelines) for off-site combustion, and methane that is collected for any other on-site or off-site use as a fuel.

Destruction means, with respect to fluorinated GHGs, the expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product.

Destruction Efficiency means the efficiency with which a destruction device reduces the GWP-weighted mass of greenhouse gases fed into the device, considering the GWP-weighted masses of both the greenhouse gases fed into the device and those exhausted from the device. The Destruction Efficiency is expressed in the following Equation A–2:

$$DE = 1 - \frac{tCO_2e_{OUT}}{tCO_2e_{IN}} \qquad \text{(Eq. A-2)}$$

Where:

DE = Destruction Efficiency
tCO_2e_{IN} = The GWP-weighted mass of GHGs fed into the destruction device
tCO_2e_{OUT} = The GWP-weighted mass of GHGs exhausted from the destruction device, including GHGs formed during the destruction process

Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized

Destruction or removal efficiency (DRE) is the efficiency of a control device to destroy or remove F–GHG and N_2O. The DRE is equal to one minus the ratio of the mass of all relevant GHG exiting the emission control device to the mass of GHG entering the emission control device.

Diesel fuel means a low sulfur fuel oil of grades 1BD or 2BD, as defined by the American Society for Testing and Materials standard ASTM D975–91, ‘‘Standard Specification for Diesel Fuel Oils’’ (as incorporated by reference in § 98.7), grades 1–GT or 2–GT, as defined by ASTM D2880–90a, ‘‘Standard Specification for Gas Turbine Fuel Oils’’ (as incorporated by reference in § 98.7), or fuel oil numbers 1 or 2, as defined by ASTM D396–90a, ‘‘Standard Specification for Fuel Oils’’ (as incorporated by reference in § 98.7).

Diesel fuel No. 1 has a distillation temperature of 550 °F at the 90 percent recovery point and conforms to ASTM D975–08 (2007) Standard Specification for Diesel Fuel Oils. It is used in high speed diesel engines such as city buses. Compared to fuel oil No. 1 it has a higher octane number, a lower sulfur content, and a higher flash point. It is blended with diesel No. 2 in the colder regions of the country to facility cold starts.

Diesel fuel No. 2 has a distillation temperature of 500 °F at the 10 percent recovery point and 640 °F at the 90 percent recovery point and is defined in ASTM D975. It is used in high speed diesel engines, such as locomotives, trucks and automobiles. Currently, there are three categories of diesel fuel No. 2 defined by sulfur content: High sulfur (>0.05%/wgt), low sulfur (<0.05%/wgt), and ultra low sulfur (<0.0015%/wgt). Ultra low sulfur is used for on road vehicles.

Diesel fuel No. 4, made by blending diesel fuel and residual fuel and conforming to ASTM D975, is used for low and medium speed diesel engines.

Digesters are systems where animal excreta are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO_2 and CH_4, which is captured and may be flared or used as fuel. There are multiple types of anaerobic digestion systems, including covered lagoon, complete mix, plug flow, and fixed film digesters.

Direct liquefaction means the conversion of coal directly into liquids, rather than passing through an intermediate gaseous state.

Direct reduction furnace means a high temperature furnace typically fired with natural gas to produce solid iron from iron ore or iron ore pellets and coke, coal, or other carbonaceous materials.

Distillate fuel oil means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes both diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4) and fuel oils (Fuel oil No. 1, No. 2, and No. 4). Fuel oils are used primarily for space heating, in industrial and commercial boilers and furnaces and for electric power generation. Diesel fuels are used in on-highway vehicles as well as in off highway engines, such as locomotives, marine engines, agricultural and construction equipment.

DOC_f means the fraction of DOC that actually decomposes under the (presumably anaerobic) conditions within the landfill.

Dry lot means a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

Electric arc furnace (EAF) means a furnace that produces molten alloy metal and heats the charge materials with electric arcs from carbon electrodes.

Electric arc furnace steelmaking means the production of carbon, alloy, or specialty steels using an EAF. This definition excludes EAFs at steel foundries and EAFs used to produce nonferrous metals.

Electrical equipment means any item used for the generation, conversion, transmission, distribution or utilization of electric energy, such as machines, transformers, apparatus, measuring instruments, or protective devices, that contains sulfur hexafluoride (SF_6) or perfluorocarbons (PFCs) (including but not limited to gas-insulated switchgear substations (GIS), gas circuit breakers (GCB), and power transformers).

Electricity generating unit or EGU means any unit that combusts solid, liquid, or gaseous fuel and is physically connected to a generator to produce electricity.

Electrothermic furnace means a furnace that heats the charged materials with electric arcs from carbon electrodes.

Emergency generator means a stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. Emergency engines operate only during emergency situations or for standard performance testing procedures as required by law or by the engine manufacturer. The hours of operation per calendar year for such standard performance testing shall not exceed 100 hours. An engine that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency engine.

Engineering estimation means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Equipment means but is not limited to each pump, compressor, pipe, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, tank, vessel, and instrumentation system in natural gas or liquid service; and any control devices or systems referenced by this subpart.

Equipment chambers means the total natural gas-containing volume within any equipment and between the equipment isolation valves.

Ethane (C_2H_6) is a colorless paraffinic gas that boils at temperatures of −127.48 °F. It is extracted from natural gas and from refinery gas streams. Ethane is a major feedstock for the petrochemical industry.

Ethylene (C_2H_4) is an olefinic hydrocarbon received from refinery processes or petrochemical processes. Ethylene is used as a petrochemical feedstock for numerous chemical applications and the production of consumer goods.

Ex refinery gate means the point at which a refined or semi-refined product leaves the refinery.

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for non-experimental furnaces.

Export means to transport a product from inside the United States to persons outside the United States, excluding United States military bases and ships for on-board use.

Exporter means any person, company, or organization of record that contracts to transfer a product from the United States to another country or that transfers products to an affiliate in another country, excluding transfers to United States military bases and ships for on-board use.

Extracted means production of carbon dioxide from carbon dioxide production wells.

Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Feed means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and flyash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

Feedstock means raw material inputs to a process that are transformed by reaction, oxidation, or other chemical or physical methods into products and by-products. Supplemental fuel burned to provide heat or thermal energy is not a feedstock.

Finished aviation gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910–07a (2002) and Military Specification MIL–G–5572.

Finished motor gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline, defined in ASTM Specifications D4814–08a (2001) or Federal Specification VV–G–1690C, has a boiling range of 122 ° to 158 °F at the 10 percent recovery point to 365 ° to 374 °F at the 90 percent recovery rate. Motor gasoline includes, conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

Fischer-Tropsch process means a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms.

Flare means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed 95 percent for non-aspirated field flares and 98 percent for steam or air asperated flares.

Flare stack means a device used to provide a safe means of combustible natural gas disposal from routine operations, upsets, or emergencies via combustion of the natural gas in an open, normally elevated flame.

Flare stack fugitive emissions means the CH_4 and CO_2 content of that portion of natural gas (typically 5 percent in non-aspirated field flares and 2 percent in steam or air asperated flares) that passes through flares un-combusted and the total CO_2 emissions of that portion of the natural gas that is combusted.

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in NAICS 327211.

Fluid coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: a traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

Fluorinated greenhouse gas means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82 Subpart A. In addition to SF_6 and NF_3, ‘‘fluorinated GHG’’ includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

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

Fuel means solid, liquid or gaseous combustible material.

Fuel ethanol (C_2H_5OH) is an anhydrous alcohol made either chemically from ethylene or biologically from the fermentation of sugars from carbohydrates found in agricultural products. It is used as a gasoline octane enhancer and as an oxygenate blendstock.

Fuel gas (still gas) means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

Fuel oil No. 1 has a distillation temperature of 400 °F at the 10 percent recovery point and 550 °F at the 90 percent recovery point and is used primarily as fuel for portable outdoor stoves and heaters. It is defined in ASTM D396–08 (2007) Standard Specification for Fuel Oils.

Fuel oil No. 2 has a distillation temperature of 400 °F at the 10 percent recovery point and 640 °F at the 90 percent recovery point and is defined in ASTM D396. It is used primarily for residential heating and for moderate capacity commercial and industrial burner units.

Fuel oil No. 4 is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil and conforms to ASTM D396 or Federal Specification VV–F–815C. and is used extensively in industrial plants and commercial burner installations that are not equipped with preheating facilities.

Fugitive emissions means unintentional equipment emissions of methane and/or carbon dioxide containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. Fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares.

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

Fugitive emissions detection instruments mean any device or instrument that has been approved for fugitive emissions detection in this rule, namely infrared fugitive emissions detection instruments, OVAs, and TVAs.

Gas collection system or landfill gas collection system means a system of pipes used to collect landfill gas from different locations in the landfill to a single location for treatment (thermal destruction) or use. Landfill gas collection systems may also include knock-out or separator drums and/or a compressor.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of gaseous fuels, and the remainder of its annual heat input from the combustion of fuel oil or other liquid fuels.

Gas monitor means an instrument that continuously measures the concentration of a particular gaseous species in the effluent of a stationary source.

Gas utilization is the quantity of GHG gas consumed (and therefore not available for emission) during the etching and/or chamber cleaning processes.

Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gasification means the conversion of a solid material into a gas.

Gathering and boosting station means a station used to gather natural gas from well or field pipelines for delivery to a natural gas processing facility or central point. Stations may also provide compression, dehydration, and/or treating services.

Glass melting furnace means a unit comprising a refractory-lined vessel in which raw materials are charged and melted at high temperature to produce molten glass.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram (kg) of a trace substance relative to that of one kg of a reference gas, i.e., CO_2.

GPA means the Gas Processors Association.

Greenhouse gas or GHG means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), chlorofluorocarbons (CFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

Heat Transfer Fluids are F–GHGs that are liquid at room temperature, have appreciable vapor pressures, and are used for temperature control during certain processes in electronic manufacturing. Heat transfer fluids used in the electronics sector include perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers.

Heel means the amount of gas that remains in a shipping container after it is discharged or off-loaded (that is no more than ten percent of the volume of the container).

High heat value or HHV means the high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.

High volume sampler means an atmospheric emissions measurement device that captures emissions from a source in a calibrated air intake and uses dual hydrocarbon sensors and other devices to measure the flow rate and combustible hydrocarbon concentrations of the fugitive emission such that the quantity of emissions is determined.

Hydrofluorocarbons or HFCs means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

Import means, with respect to fluorinated GHGs and nitrous oxide, to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:

(1) Off-loading used or excess fluorinated GHGs or nitrous oxide of U.S. origin from a ship during servicing,

(2) Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous oxide had been admitted into Mexico in bond and were of U.S. origin, and

(3) Bringing fluorinated GHGs or nitrous oxide into the U.S. when transported in a consignment of personal or household effects or in a similar non-commercial situation normally exempted from U.S. Customs attention.

Importer means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country. An importer includes the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term also includes, as appropriate:

(1) The consignee.

(2) The importer of record.

(3) The actual owner.

(4) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

Indurating furnace means a furnace where unfired taconite pellets, called green balls, are hardened at high temperatures to produce fired pellets for use in a blast furnace. Types of indurating furnaces include straight gate and grate kiln furnaces.

Infrared remote fugitive emissions detection instrument means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere. For the purpose of this rule, it must detect the presence of methane.

In-line kiln/raw mill means a system in a portland cement production process where a dry kiln system is integrated with the raw mill so that all or a portion of the kiln exhaust gases are used to perform the drying operation of the raw mill, with no auxiliary heat source used. In this system the kiln is capable of operating without the raw mill operating, but the raw mill cannot operate without the kiln gases, and consequently, the raw mill does not generate a separate exhaust gas stream.

Integrated process means a process that produces a petrochemical as well as one or more other chemicals that are part of other source categories under this part. An example of an integrated process is the production of both hydrogen for sale (i.e., a merchant hydrogen facility) and methanol from synthesis gas created by steam reforming of methane.

Interstate pipeline means a natural gas pipeline designated as interstate pipelines under the Natural Gas Act, 15 U.S.C. 717a.

Intrastate pipeline means a natural gas pipeline not subject to the jurisdiction of the Federal Energy Regulatory Commission as described in 15 U.S.C. 3301.

Isobutane (C_4H_{10}) is a normally gaseous branch chain hydrocarbon extracted from natural gas or refinery gas streams. A colorless paraffinic gas that boils at 10.9 °F, it is used as a feedstock in refineries.

Kerosene-type jet fuel means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. It meets ASTM Specification D1655–08a (2001) and Military Specification MIL–T–5624P and MIL–T–83133D (JP–5 and JP–8).

Kiln means a device, including any associated preheater or precalciner devices, that produces clinker by heating limestone and other materials for subsequent production of portland cement.

Kiln exhaust gas bypass means alkali bypass.

Landfill means an area of land or an excavation in which wastes are placed for permanent disposal and that is not a land application unit, surface impoundment, injection well, or waste pile as those terms are defined under § 257.2 of this chapter.

Landfill gas means gas produced as a result of anaerobic decomposition of waste materials in the landfill. Landfill gas generally contains 40 to 60 percent methane on a dry basis, typically less than 1 percent non-methane organic chemicals, and the remainder being carbon dioxide.

Lime is the generic term for a variety of chemical compounds that are produced by the calcination of limestone or dolomite. These products include but are not limited to calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, and dolomitic hydrate.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to −260 degrees Fahrenheit at atmospheric pressure.

Liquefied natural gas import and export facilities mean onshore and/or offshore facilities that send out exported or receive imported liquefied natural gas, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

Liquefied natural gas storage facilities means an onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

Liquid/Slurry means manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.

LNG import and export facility fugitive emissions mean natural gas releases from valves, connectors, storage tanks, flanges, open-ended lines, pressure relief valves, boil-off-gas recovery, send outs (pumps and vaporizers), packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

LNG storage station fugitive emissions mean natural gas releases from valves, connectors, flanges, open-ended lines, storage tanks, pressure relief valves, liquefaction process units, packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

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

Mass-balance approach means a method for estimating emissions of fluorinated greenhouse gases from use in equipment that can be applied to aggregates of units (for example by system). In this approach, annual emissions are the difference between the quantity of gas consumed in the year and the quantity of gas used to fill the net increase in equipment capacity or to replace destroyed gas.

Maximum rated heat input capacity means the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

Maximum rated input capacity means the maximum amount of municipal solid waste per day (in tons/day) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Mcf means thousand cubic feet.

Meter means a device that measures gas flow rate from a fugitive emissions source or through a conduit by detecting a condition (pressure drop, spin induction, temperature loss, electronic signal) that varies in proportion to flow rate or measures gas velocity in a manner that can calculate flow rate.

Methane conversion factor means the extent to which the CH_4 producing capacity (B_o) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

Methane correction factor means an adjustment factor applied to the methane generation rate to account for portions of the landfill that remain aerobic. The methane correction factor can be considered the fraction of the total landfill waste volume that is ultimately disposed of in an anaerobic state. Managed landfills that have soil or other cover materials have a methane correction factor of 1.

Miscellaneous products include all petroleum products not classified elsewhere. It includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.

MMBtu means million British thermal units.

Municipal solid waste landfill or MSW landfill means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (§ 257.2 of this chapter) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads. An MSW landfill may be publicly or privately owned.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse.

N_2O means nitrous oxide.

NAESB is the North American Energy Standards Board.

Nameplate capacity means the full and proper charge of gas specified by the equipment manufacturer to achieve the equipment's specified performance. The nameplate capacity is typically indicated on the equipment's nameplate; it is not necessarily the actual charge, which may be influenced by leakage and other emissions.

Naphtha-type jet fuel means a fuel in the heavy naphtha boiling range having an average gravity of 52.8 API and meeting Military Specification MIL–T–5624L (Grade JP–4). It is used primarily for military turbojet and turboprop aircraft because it has a lower freeze point than other aviation fuels and meets engine requirements at high altitudes and speeds.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Natural gas driven pneumatic manual valve actuator device means valve control devices that use pressurized natural gas to provide the energy required for an operator to manually open, close, or throttle a liquid or gas stream. Typical manual control applications include, but are not limited to, equipment isolation valves, tank drain valves, pipeline valves.

Natural gas driven pneumatic manual valve actuator device fugitive emissions means natural gas released due to manual actuation of natural gas pneumatic valve actuation devices, including, but not limited to, natural gas diaphragm and pneumatic-hydraulic valve actuators.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Natural gas driven pneumatic pump fugitive emissions means natural gas released from pumps that are powered or assisted by pressurized natural gas.

Natural gas driven pneumatic valve bleed device means valve control devices that use pressurized natural gas to transmit a process measurement signal to a valve actuator to automatically control the valve opening. Typical bleeding process control applications include, but are not limited to, pressure, temperature, liquid level, and flow rate regulation.

Natural gas driven pneumatic valve bleed devices fugitive emissions means the continuous or intermittant release of natural gas from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g. liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

Natural gas liquids (NGL) means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally, such liquids consist of primarily ethane, propane, butane, and isobutane, primarily pentanes produced from natural gas at lease separators and field facilities. For the purposes of subpart NN only, natural gas liquids does not include lease condensate. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

Natural gas processing facilities are engaged in the extraction of natural gas liquids from produced natural gas; fractionation of mixed natural gas liquids to natural gas products; and removal of carbon dioxide, sulfur compounds, nitrogen, helium, water, and other contaminants. Natural gas processing facilities also encompass gathering and boosting stations that include equipment to phase-separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility.

Natural gas products means products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus.

Natural gas transmission compression facility means any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids.

NIST means the United States National Institute of Standards and Technology.

Nitric acid production line means a series of reactors and absorbers used to produce nitric acid.

Nitrogen excreted is the nitrogen that is excreted by livestock in manure and urine.

Non-crude feedstocks means natural gas liquids, hydrogen and other hydrocarbons, and petroleum products that are input into the atmospheric distillation column or other processing units in a refinery

Non-pneumatic pump means any pump that is not pneumatically powered with pressurized gas of any type, such as natural gas, air, or nitrogen.

Non-pneumatic pump fugitive emissions means natural gas released through connectors and flanges of electric motor or engine driven pumps.

Non-recovery coke oven battery means a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered.

Non-steam aspirated flare means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

Offshore means tidal-affected borders of the U.S. lands, both state and Federal, adjacent to oceans, bays, lakes or other normally standing water.

Offshore petroleum and natural gas production facilities means any platform structure, floating in the ocean or lake, fixed on ocean or lake bed, or located on artificial islands in the ocean or lake, that houses equipment to extract hydrocarbons from ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipment for separation of liquids from natural gas components, dehydration of natural gas, extraction of H_2S and CO_2 from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters.

Offshore platform pipeline fugitive emissions means natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities.

Oil/water separator means equipment used to routinely handle oily-water streams, including gravity separators or ponds and air flotation systems.

Oil-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

Open-ended line fugitive emissions means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

Open-ended valve or Lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating hours means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

Operating pressure means the containment pressure that characterizes the normal state of gas and/or liquid inside a particular process, pipeline, vessel or tank.

Operator means any person who operates or supervises a facility or supply operation.

Organic monitoring device means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as IR, photoionization, or thermal conductivity.

Organic vapor analyzer (OVA) means an organic monitoring device that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

Owner means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supply operation.

Oxygenated gasoline means gasoline which contains a measurable amount of oxygenate.

Oxygenates means substances which, when added to gasoline increase the oxygen content of the gasoline. Common oxygenates are ethanol CH_3-CH_2OH, Methyl Tertiary Butl Ether $(CH_3)_3COCH_3$ (MTBE), Ethyl Tertial Butl Ether $(CH_3)_3COC_2H$ (ETBE), Tertiary Amyl Methyl Ether $(CH_3)(_2C2H_5)$ $COCH_3$ (TAME), Diisopropyl Ether $(CH_3)_2CHOCH(CH_3)_2$ (DIPE), and Methanol CH_3OH. Lawful use of any of the substances or any combination of these substances requires that they be ''substantially similar'' under section 211(f)(1) of the Clean Air Act.

Pasture/Range/Paddock means the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

Pentanes plus is a mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas. Pentanes plus includes isopentane, natural gasoline, and plant condensate.

Perfluorocarbons or PFCs means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

Petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black.

Petrochemical feedstocks means feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. This category is usually divided into naphtha less than 401 °F and other oils greater than 401 °F.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Petroleum coke means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent) and has low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals.

Petroleum product means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together. Petroleum products may be combusted for energy use, or they may be used either for non-energy processes or as non-energy products. The definition of petroleum product for importers and exporters excludes asphalt and road oil, lubricants, waxes, plastics, and plastics products.

Platform fugitive emissions means natural gas released from equipment and equipment components including valves, pressure relief valves, connectors, tube fittings, open-ended lines, ports, and hatches. This does not include fugitive emissions from equipment and components reported elsewhere for this rule.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if:

(1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

Post-coal mining activities means the storage, processing, and transport of extracted coal.

Poultry manure with litter is similar to cattle and swine deep bedding except usually not combined with a dry lot or pasture. Typically used for all poultry breeder flocks and for the production of meat type chickens (broiler) and other fowl.

Poultry manure without litter systems may manage manure in a liquid form, similar to open pits in enclosed animal confinement facilities. These systems may alternatively be designed and operated to dry manure as it accumulates. The latter is known as a high-rise manure management system and is a form of passive windrow manure composting when designed and operated properly.

Precision of a measurement at a specified level (e.g., one percent of full scale) means that 95 percent of repeat measurements made by a device or technique fall within the range bounded by the mean of the measurements plus or minus the specified level.

Pressed and blown glass means glass which is pressed, blown, or both, into products such as light bulbs, glass fiber, technical glass, and other products listed in NAICS 327212.

Pressure relief device or pressure relief valve or pressure safety valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device includes, but is not limited to, a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Primary product means the product of a process that is produced in greater mass quantity than any other product of the process.

Process emissions means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of *process* CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

Process Type, for purposes of electronics manufacturing, means the kind of electronics manufacturing process, i.e., etching, cleaning, or chemical vapor deposition using N_2O.

Process gas means any gas generated by an industrial process such as petroleum refining.

Processing facility fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system fugitive emissions, packing and gaskets in natural gas processing facilities. This does not include fugitive emissions from equipment and components reported elsewhere for this rule, such as compressor fugitive emissions; acid gas removal, blowdown, wet seal oil degassing, and dehydrator vents; and flare stacks.

Production process unit means equipment used to capture a carbon dioxide stream.

Propane means the normally gaseous paraffinic compound (C_3H_8), which includes all products covered by Natural Gas Policy Act Specifications for commercial and HD–5 propane and ASTM Specification D 1835. It excludes feedstock propanes, which are propanes not classified as consumer grade propanes, including the propane portion of any natural gas liquid mixes, i.e., butane-propane mix.

Propylene (C_3H_6) is an olefinic hydrocarbon recovered from refinery processes or petrochemical processes.

Pulp Mill Lime kiln means the combustion units (e.g., rotary lime kiln or fluidized bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal fugitive emissions means natural gas released from the seal face between the pump internal chamber and the atmosphere.

Pushing means the process of removing the coke from the coke oven at the end of the coking cycle. Pushing begins when coke first begins to fall from the oven into the quench car and ends when the quench car enters the quench tower.

Raw mill means a ball and tube mill, vertical roller mill or other size reduction equipment, that is not part of an in-line kiln/raw mill, used to grind feed to the appropriate size. Moisture may be added or removed from the feed during the grinding operation. If the raw mill is used to remove moisture from feed materials, it is also, by definition, a raw material dryer. The raw mill also includes the air separator associated with the raw mill.

RBOB (reformulated gasoline for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated gasoline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reciprocating compressor rod packing fugitive emissions means natural gas released from a connected tubing vent and/or around a piston rod where it passes through the rod packing case. It also includes emissions from uncovered distance piece, rod packing flange (on each cylinder), any packing vents, cover plates (on each cylinder), and the crankcase breather cap.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Refined petroleum product means petroleum products produced from the processing of crude oil, lease condensate, natural gas and other hydrocarbon compounds

Refinery fuel gas (still gas) means any gas generated at a petroleum refinery, or any gas generated by a refinery process unit, that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

Reformulated gasoline means any gasoline whose formulation has been certified under 40 CFR 80.40, and which meets each of the standards and requirements prescribed under 40 CFR 80.41.

Re-gasification means the process of vaporizing liquefied natural gas to gaseous phase natural gas.

Research and development process unit means a process unit whose purpose is to conduct research and development for new processes and products and is not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.

Residual fuel oil means a classification for the heavier fuel oils, No. 5 and No. 6. No. 5 is also known as Navy Special and is used in steam powered vessels in government service and inshore power plants. No.6 includes Bunker C and is used for the production of electric power, space heating, vessel bunkering and various industrial purposes.

Residue gas means natural gas from which natural gas processing facilities liquid products and, in some cases, non-hydrocarbon components have been extracted.

Rotameter means a flow meter in which gas flow rate upward through a tapered tube lifts a ''float bob'' to an elevation related to the gas flow rate indicated by etched calibrations on the wall of the tapered tube.

Rotary lime kiln means a unit with an inclined rotating drum that is used to produce a lime product from limestone by calcination.

Semi-refined petroleum product means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial refining of crude oil and include the following: naphthas and lighter oils; kerosene and light gas oils; heavy gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

SF_6 means sulfur hexafluoride.

Shutdown means the cessation of operation of an emission source for any purpose.

Silicon carbide means an artificial abrasive produced from silica sand or quartz and petroleum coke.

Simulation software means a calibrated, empirical computer program that uses physical parameters and scientific laws to numerically simulate the performance variables of a physical process, outputting such parameters as emission rates from which methane emissions can be estimated.

Sinter process means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Smelting furnace means a furnace in which lead-bearing materials, carbon-containing reducing agents, and fluxes are melted together to form a molten mass of material containing lead and slag.

Solid storage is the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Special naphthas means all finished products with the naphtha boiling range (290° to 470 °F) that are used as paint thinners, cleaners or solvents.

Spent liquor solids means the dry weight of the solids in the spent pulping liquor that enters the chemical recovery furnace or chemical recovery combustion unit.

Spent pulping liquor means the residual liquid collected from on-site pulping operations at chemical pulp facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

Standard conditions or standard temperature and pressure (STP) means 60 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Standby means for an equipment to be in a state ready for operation, but not operating.

Steam aspirated flare means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

Steam reforming means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

Storage station fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas storage station. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Storage tank means other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Storage tank fugitive emissions means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

Storage wellhead fugitive emissions means natural gas released from storage station wellhead components including but not limited to valves, OELs, connectors, flanges, and tube fittings.

Sub-surface or subsurface facility means for the purposes of this rule, a natural gas facility, such as a pipeline and metering and regulation station in a closed vault below the land surface of the Earth.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H_2S) and/or sulfur dioxide (SO_2) at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device.

Supplemental fuel means a fuel burned within a petrochemical process that is not produced within the process itself.

Supplier means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

Taconite iron ore processing means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are used as the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.

Tanker unloading means pumping of liquid hydrocarbon (e.g., crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

Toxic vapor analyzer (TVA) means an organic monitoring device that uses a flame ionization detector and photoionization detector to measure the concentrations in air of combustible organic vapors from 9 parts per million and exceeding 10,000 parts per million sucked into the probe.

Trace concentrations means concentrations of less than 0.1 percent by mass of the process stream.

Trained technician means a person who has completed a vendor provided or equivalent training program and demonstrated proficiency to use specific equipment for its intended purpose, such as high volume sampler for the purposes of this rule.

Transform means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes. Transformation does not include burning of nitrous oxide.

Transshipment means the continuous shipment of nitrous oxide or a fluorinated GHG from a foreign state of origin through the United States or its territories to a second foreign state of final destination, as long as the shipment does not enter into United States jurisdiction. A transshipment, as it moves through the United States or its territories, cannot be re-packaged, sorted or otherwise changed in condition.

Transmission compressor station fugitive emissions means natural gas released from all components including but not limited to valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas transmission compressor stations. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule, such as compressor fugitive emissions.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate ($NaCO_3.NaHCO_3.2H_2O$).

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Ultimate analysis means the determination of the percentages of carbon, hydrogen, nitrogen, sulfur, and chlorine and (by difference) oxygen in the gaseous products and ash after the complete combustion of a sample of an organic material.

Uncovered anaerobic lagoons are a type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.

Underground natural gas storage facility means a subsurface facility, including but not limited to depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at a natural gas underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.

United States means the 50 states, the District of Columbia, and U.S. possessions and territories.

Unstabilized crude oil means, for the purposes of this subpart, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize liquefied natural gas to supply transmission and distribution pipelines, or consumers with natural gas.

Ventilation system means a system deployed within a mine to ensure that CH_4 levels remain within safe concentrations.

Volatile solids are the organic material in livestock manure and consist of both biodegradable and non-biodegradable fractions.

Waelz kiln means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

Waste feedstocks are non-crude feedstocks that have been contaminated, downgraded, or no longer meet the specifications of the product category or end-use for which they were intended. Waste feedstocks include but are not limited to: Used plastics, used engine oils, used dry cleaning solvents, and trans-mix (mix of products at the interface in delivery pipelines).

Waxes means a solid or semi-solid material at 77 °F consisting of a mixture of hydrocarbons obtained or derived from petroleum fractions, or through a Fischer-Tropsch type process, in which the straight chained paraffin series predominates.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as ''wet gas''.

Wool fiberglass means fibrous glass of random texture, including fiberglass insulation, and other products listed in NAICS 327993.

You means the owner or operator subject to Part 98.

Zinc smelters means a facility engaged in the production of zinc metal, zinc oxide, or zinc alloy products from zinc sulfide ore concentrates, zinc calcine, or zinc-bearing scrap and recycled materials through the use of pyrometallurgical techniques involving the reduction and volatization of zinc-bearing feed materials charged to a furnace.

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

The materials listed in this section are incorporated by reference for use in this part and are incorporated as they existed on the date of approval of this part.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240–02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(2) ASTM D388–05, Standard Classification of Coals by Rank.

(3) ASTM D396–08, Standard Specification for Fuel Oils.

(4) ASTM D975–08, Standard Specification for Diesel Fuel Oils.

(5) ASTM D1250–07, Standard Guide for Use of the Petroleum Measurement Tables.

(6) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(7) ASTM Specification D1835–05 (2005).

(8) ASTM D1945–03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(9) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(10) ASTM D2013–07, Standard Practice of Preparing Coal Samples for Analysis.

(11) ASTM D2234/D2234M–07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502–04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(13) ASTM D2503–92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(14) ASTM D2880–03, Standard Specification for Gas Turbine Fuel Oils.

(15) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(16) ASTM D3238–95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(17) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(18) ASTM Specification D3699–07, Standard Specification for Kerosene.

(19) ASTM D4057–06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(20) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(21) ASTM Specification D4814–08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(22) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

(23) ASTM D5291–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(24) ASTM D5373–08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(25) ASTM D5865–07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(26) ASTM D6316–04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(27) ASTM D6866–06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(28) ASTM E1019–03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(29) ASTM E1915–07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(30) ASTM CS–104 (1985), Carbon Steel of Medium Carbon Content.

(31) ASTM D 7459–08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

(32) ASTM D6060–96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

(33) ASTM D 2502–88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

(34) ASTM C25–06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.

(35) UOP539–97 Refinery Gas Analysis by Gas Chromatography.

(b) The following materials are available for purchase from the American Society of Mechanical

Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007–2900:

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(3) ASME-MFC–5M–1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(4) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(5) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(6) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank.

(2) ISO/TR 15349–1:1998, Unalloyed steel—Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).

(3) ISO/TR 15349–3: 1998, Unalloyed steel—Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172–96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(2) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005–4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3—Tank Gauging:

(i) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(ii) Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(iii) Section 3—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems:

(i) Section 2—Displacement Provers, Third Edition, September 2003.

(ii) Section 5—Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329.

(1) ASHRAE 41.8–1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

§ 98.8 What are the compliance and enforcement provisions of this part?

Any violation of the requirements of this part shall be a violation of the Clean Air Act. A violation includes, but is not limited to, failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emission, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

TABLE A–1 OF SUBPART A—GLOBAL WARMING POTENTIALS (100-YEAR TIME HORIZON)

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	21
Nitrous oxide	10024–97–2	N_2O	310
HFC-23	75–46–7	CHF_3	11,700
HFC-32	75–10–5	CH_2F_2	650
HFC-41	593–53–3	CH_3F	150
HFC-125	354–33–6	C_2HF_5	2,800
HFC-134	359–35–3	$C_2H_2F_4$	1,000
HFC-134a	811–97–2	CH_2FCF_3	1,300
HFC-143	430–66–0	$C_2H_3F_3$	300
HFC-143a	420–46–2	$C_2H_3F_3$	3,800
HFC-152	624–72–6	CH_2FCH_2F	53
HFC-152a	75–37–6	CH_3CHF_2	140
HFC-161	353–36–6	CH_3CH_2F	12
HFC-227ea	431–89–0	C_3HF_7	2,900
HFC-236cb	677–56–5	$CH_2FCF_2CF_3$	1,340
HFC-236ea	431–63–0	CHF_2CHFCF_3	1,370

Table A–1 of Subpart A—Global Warming Potentials (100-Year Time Horizon)—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
HFC-236fa	690–39–1	$C_3H_2F_6$	6,300
HFC-245ca	679–86–7	$C_3H_3F_5$	560
HFC-245fa	460–73–1	$CHF_2CH_2CF_3$	1,030
HFC-365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	794
HFC-43-10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	1,300
Sulfur hexafluoride	2551–62–4	SF_6	23,900
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	17,700
Nitrogen trifluoride	7783–54–2	NF_3	17,200
PFC-14 (Perfluoromethane)	75–73–0	CF_4	6,500
PFC-116 (Perfluoroethane)	76–16–4	C_2F_6	9,200
PFC-218 (Perfluoropropane)	76–19–7	C_3F_8	7,000
Perfluorocyclopropane	931–91–9	c-C_3F_6	17,340
PFC-3-1-10 (Perfluorobutane)	355–25–9	C_4F_{10}	7,000
Perfluorocyclobutane	115–25–3	c-C_4F_8	8,700
PFC-4-1-12 (Perfluoropentane)	678–26–2	C_5F_{12}	7,500
PFC-5-1-14 (Perfluorohexane)	355–42–0	C_6F_{14}	7,400
PFC-9-1-18	306–94–5	$C_{10}F_{18}$	7,500
HCFE-235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	350
HFE-43-10pccc (H-Galden 1040x)	NA	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HFE-125	3822–68–2	CHF_2OCF_3	14,900
HFE-134	1691–17–4	CHF_2OCHF_2	6,320
HFE-143a	421–14–7	CH_3OCF_3	756
HFE-227ea	2356–62–9	$CF_3CHFOCF_3$	1,540
HFE-236ca12 (HG-10)	NA	$CHF_2OCF_2OCHF_2$	2,800
HFE-236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	989
HFE-236fa	20193–67–3	$CF_3CH_2OCF_3$	487
HFE-245cb2	22410–44–2	$CH_3OCF_2CF_3$	708
HFE-245fa1	NA	$CHF_2CH_2OCF_3$	286
HFE-245fa2	1885–48–9	$CHF_2OCH_2CF_3$	659
HFE-254cb2	425–88–7	$CH_3OCF_2CHF_2$	359
HFE-263fb2	460–43–5	$CF_3CH_2OCH_3$	11
HFE-329mcc2	67490–36–2	$CF_3CF_2OCF_2CHF_2$	919
HFE-338mcf2	156–05–3	$CF_3CF_2OCH_2CF_3$	552
HFE-338pcc13 (HG-01)	NA	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE-347mcc3	28523–86–6	$CH_3OCF_2CF_2CF_3$	575
HFE-347mcf2	NA	$CF_3CF_2OCH_2CHF_2$	374
HFE-347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	580
HFE-356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	101
HFE-356pcc3	NA	$CH_3OCF_2CF_2CHF_2$	110
HFE-356pcf2	NA	$CHF_2CH_2OCF_2CHF_2$	265
HFE-356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	502
HFE-365mcf3	NA	$CF_3CF_2CH_2OCH_3$	11
HFE-374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	557
HFE-449sl (HFE-7100) Chemical blend	163702–07–6 163702–08–7	$C_4F_9OCH_3$ $(CF_3)_2CFCF_2OCH_3$.	297
HFE-569sf2 (HFE-7200) Chemical blend	163702–05–4 163702–06–5	$C_4F_9OC_2H_5$ $(CF_3)_2CFCF_2OC_2H_5$.	59
Sevoflurane	28523–86–6	$CH_2FOCH(CF_3)_2$	345
NA	13171–18–1	$(CF_3)_2CHOCH_3$	27
NA	26103–08–2	$CHF_2OCH(CF_3)_2$	380
NA	NA	$-(CF_2)_4CH(OH)-$	73
NA	NA	$CH_3OCF(CF_3)_2$	343
NA	NA	$(CF_3)_2CHOH$	195
NA	NA	$CF_3CF_2CH_2OH$	42
PFPMIE	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	10,300

NA = not available.

Table A–2 of Subpart A—Units of Measure Conversions

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462.
Pounds (lbs)	Kilograms (kg)	0.45359.
Pounds (lbs)	Metric tons	4.53592×10^{-4}.
Short tons	Pounds (lbs)	2,000.
Short tons	Metric tons	0.90718.
Metric tons	Short tons	1.10231.
Metric tons	Kilograms (kg)	1,000.
Cubic meters (m^3)	Cubic feet (ft^3)	35.31467.

TABLE A–2 OF SUBPART A—UNITS OF MEASURE CONVERSIONS—Continued

To convert from	To	Multiply by
Cubic feet (ft^3)	Cubic meters (m^3)	0.028317.
Gallons (liquid, US)	Liters (l)	3.78541.
Liters (l)	Gallons (liquid, US)	0.26417.
Barrels of Liquid Fuel (bbl)	Cubic meters (m^3)	0.15891.
Cubic meters (m^3)	Barrels of Liquid Fuel (bbl)	6.289.
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42.
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810.
Gallons (liquid, US)	Cubic meters (m^3)	0.0037854.
Liters (l)	Cubic meters (m^3)	0.001.
Feet (ft)	Meters (m)	0.3048.
Meters (m)	Feet (ft)	3.28084.
Miles (mi)	Kilometers (km)	1.60934.
Kilometers (km)	Miles (mi)	0.62137.
Square feet (ft^2)	Acres	2.29568×10^{-5}.
Square meters (m^2)	Acres	2.47105×10^{-4}.
Square miles (mi^2)	Square kilometers (km^2)	2.58999.
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	°C = (5/9) × (°F − 32).
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	°F = (9/5) × °C + 32.
Degrees Celsius (°C)	Kelvin (K)	K = °C + 273.15.
Kelvin (K)	Degrees Rankine (°R)	1.8.
Joules	Btu	9.47817×10^{-4}.
Btu	MMBtu	1×10^{-6}.
Pascals (Pa)	Inches of Mercury (in Hg)	2.95334×10^{-4}.
Inches of Mercury (inHg)	Pounds per square inch (psi)	0.49110.
Pounds per square inch (psi)	Inches of Mercury (in Hg)	2.03625.

Subpart B—[Reserved]

Subpart C—General Stationary Fuel Combustion Sources

§ 98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include portable equipment or generating units designated as emergency generators in a permit issued by a state or local air pollution control agency.

§ 98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary combustion sources and the facility meets the requirements of either *§ 98.2(a)(1), (2), or (3).*

§ 98.32 GHGs to report.

You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit.

§ 98.33 Calculating GHG emissions.

The owner or operator shall use the methodologies in this section to calculate the GHG emissions from stationary fuel combustion sources, except for electricity generating units that are subject to the Acid Rain Program. The GHG emissions calculation methods for Acid Rain Program units are addressed in subpart D of this part.

(a) *CO_2 emissions from fuel combustion.* For each stationary fuel combustion unit, the owner or operator shall use the four-tiered approach in this paragraph, subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section.

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting a fuel-specific default CO_2 emission factor (from Table C–1 of this subpart), a default high heating value (from Table C–1 of this subpart), and the annual fuel consumption (from company records kept as provided in this rule) into the Equation C–1 of this section:

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

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

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

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) *Tier 2 Calculation Methodology.* Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting measured high heat values, a default CO_2 emission factor (from Table C–1 or Table C–2 of this subpart), and the quantity of fuel combusted (from company records kept as provided in this rule) into the following equations:

(i) Equation C–2a of this section applies to any type of fuel, except for municipal solid waste (MSW):

$$CO_2 = \sum_{p=1}^{n} 1\,x\,10^{-3}\,(Fuel)_p * (HHV)_p * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

n = Number of required heat content measurements for the year.

$(Fuel)_p$ = Mass or volume of the fuel combusted during the measurement period ''p'' (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

p = Measurement period (month).

$(HHV)_p$ = High heat value of the fuel for the measurement period (mmBtu per mass or volume).

EF = Fuel-specific default CO_2 emission factor, from Table C–1 or C–2 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) In Equation C–2a of this section, the value of ''n'' depends upon the frequency at which high heat value (HHV) measurements are required under § 98.34(c). For example, for natural gas, which requires monthly sampling and analysis, n = 6 if the unit combusts natural gas in only 6 months of the year.

(iii) For MSW combustion, use Equation C–2b of this section:

$$CO_2 = 1\,x\,10^{-3}\,(Steam)\,(B)\,(EF) \qquad \text{(Eq. C-2b)}$$

Where:

CO_2 = Annual CO_2 mass emissions from MSW combustion (metric tons).

Steam = Total mass of steam generated by MSW combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Default CO_2 emission factor for MSW, from Table C–3 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following Equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

(i) For a solid fuel, use Equation C–3 of this section:

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_n * (CC)_n \qquad \text{(Eq. C-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

N = Number of required carbon content determinations for the year.

$(Fuel)_n$ = Mass of the solid fuel combusted in month ''n'' (metric tons).

P = Measurement period (month).

$(CC)_n$ = Carbon content of the solid fuel, from the fuel analysis results for month ''n'' (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(ii) For a liquid fuel, use Equation C–4 of this section:

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_n * (CC)_n * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

N = Number of required carbon content determinations for the year.

$(Fuel)_n$ = Volume of the liquid fuel combusted in month ''n'' (gallons).

P = Measurement period (month).

$(CC)_n$ = Carbon content of the liquid fuel, from the fuel analysis results for month ''n'' (kg C per gallon of fuel).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C–5 of this section:

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_n * (CC)_n * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).

N = Number of required carbon content and molecular weight determinations for the year.

$(Fuel)_n$ = Volume of the gaseous fuel combusted on day ''n'' or in month ''n'', as applicable (scf).

P = Measurement period (month or day, as applicable).

$(CC)_n$ = Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) In applying Equation C–5 of this section to natural gas combustion, the CO_2 mass emissions are calculated only for those months in which natural gas is combusted during the reporting year. For the combustion of other gaseous fuels (e.g., refinery gas or process gas), the CO_2 mass emissions are calculated only for those days on which the gaseous fuel is combusted during the reporting year. For example, if the unit combusts process gas on 250 of the 365 days in the year, then n = 250 in Equation C–5 of this section.

(4) *Tier 4 Calculation Methodology.* Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(1)(iv)(D) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C–6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18\,x\,10^{-7} * C_{CO_2} * Q \qquad \text{(Eq. C-6)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).

C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18 x 10^{-7} = Conversion factor (tons/scf-% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. The owner or operator shall either continuously monitor the stack gas moisture content as described in § 75.11(b)(2) of this chapter or, for certain types of fuel, use a default moisture percentage from § 75.11(b)(1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C–6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

Where:

CO_2^* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C–6 of this section, uncorrected (tons/hr).

$\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations, in accordance with Equation F–14a or F–14b (as applicable) in appendix F to part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter are combusted in the unit. If the O2 monitoring option is selected, the F-factors used in Equations F–14a and F–14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter, as applicable. If Equation F–14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with § 75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from § 75.11(b)(1) of this chapter.

(v) Each hourly CO_2 mass emission rate from Equation C–6 or C–7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over the entire calendar year.

(vii) If both biogenic fuel and fossil fuel are combusted during the year, determine the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(b) *Use of the four tiers.* Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology may be used for any type of fuel combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, provided that:

(i) An applicable default CO_2 emission factor and an applicable default high heat value for the fuel are specified in Table C–1 of this subpart.

(ii) The owner or operator does not perform, or receive from the entity supplying the fuel, the results of fuel sampling and analysis on a monthly (or more frequent) basis that includes measurements of the HHV. If the owner or operator performs such fuel sampling and analysis or receives such fuel sampling and analysis results, the Tier 1 Calculation Methodology shall not be used, and the Tier 2, Tier 3, or Tier 4 Calculation Methodology shall be used instead.

(2) The Tier 1 Calculation Methodology may also be used to calculate the biogenic CO_2 emissions from a unit of any size that combusts wood, wood waste, or other solid biomass-derived fuels, except when the Tier 4 Calculation Methodology is used to quantify the total CO_2 mass emissions. If the Tier 4 Calculation Methodology is used, the biogenic CO_2 emissions shall be calculated according to paragraph (e) of this section.

(3) The Tier 2 Calculation Methodology may be used for any type of fuel combusted in any unit with a maximum rated heat input capacity of

250 mmBtu/hr or less, provided that a default CO_2 emission factor for the fuel is specified in Table C–1 or C–2 of this subpart.

(4) The Tier 3 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when the use of Tier 4 is required or elected, as provided in paragraph (b)(5) of this section.

(5) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used for a unit if:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit:

(A) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) and (C) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

(6) The Tier 4 Calculation Methodology, if selected or required, shall be used beginning on:

(i) January 1, 2010, for a unit is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, the owner or operator shall use the Tier 3 Calculation Methodology in 2010.

(c) *Calculation of CH_4 and N_2O emissions from all fuel combustion.* Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources as follows:

(1) For units subject to the requirements of the Acid Rain Program and for other units monitoring and reporting heat input on a year-round basis according to § § 75.10(c) and 75.64 of this chapter, use Equation C–8 of this section:

$$CH_4 \text{ or } N_2O = 1\,x\,10^{-3} * (HI)_A * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from the fuel, derived from the electronic data report required under § 75.64 of this chapter (mmBtu).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–3 of this subpart (kg CH_4 or N_2O per mmBtu).

1 x 10^{-3} = Conversion factor from kg to metric tons.

(2) For all other units, use the applicable equations and procedures in paragraphs (c)(2) through (4) of this section to calculate the annual CH_4 and N_2O emissions.

(i) If a default high heat value for a particular fuel is specified in Table C–1 of this subpart and if the HHV is not measured or provided by the entity supplying the fuel on a monthly (or more frequent) basis throughout the year, use Equation C–9 of this section:

$$CH_4 \text{ or } N_2O = 1\,x\,10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-9)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, from company records (mass or volume per year).

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

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–3 of this subpart (kg CH_4 or N_2O per mmBtu).

1 x 10^{-3} = Conversion factor from kilograms to metric tons.

(ii) If the high heat value of a particular fuel (except for municipal solid waste) is measured on a monthly (or more frequent) basis throughout the year, or if such data are provided by the entity supplying the fuel, use Equation C–10a of this section:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} 1\,x\,10^{-3} * (Fuel)_p * (HHV)_p * EF \qquad \text{(Eq. C-10a)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

n = Number of required heat content measurements for the year.

$(Fuel)_p$ = Mass or volume of the fuel combusted during the measurement

period ''p'' (mass or volume per unit time).
$(HHV)_p$ = Measured high heat value of the fuel for period ''p'' (mmBtu per mass or volume).
p = Measurement period (day or month, as applicable).
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–3 of this subpart (kg CH_4 or N_2O per mmBtu).
1 x 10 ^{3} = Conversion factor from kilograms to metric tons.

(iii) For municipal solid waste combustion, use Equation C–10b of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \ or \ N_2O = 1 \, x \, 10^{-3} \ (Steam) \ (B) \ (EF) \qquad \text{(Eq. C-10b)}$$

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam = Total mass of steam generated by MSW combustion during the reporting year (lb steam).
B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–3 of this subpart (kg CH_4 or N_2O per mmBtu).
1 x 10 ^{3} = Conversion factor from kilograms to metric tons.

(3) Multiply the result from Equations C–8, C–9, C–10a, or C–10b of this section (as applicable) by the global warming potential (GWP) factor to convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent.

(4) If, for a particular type of fuel, default CH_4 and N_2O emission factors are not provided in Table C–4 of this subpart, the owner or operator may, subject to the approval of the Administrator, develop site-specific CH_4 and N_2O emission factors, based on the results of source testing.

(d) *Calculation of CO_2 from sorbent.* (1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use the following equation to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = S * R * \left(\frac{MW_{CO2}}{MW_S} \right) \qquad \text{(Eq. C-11)}$$

Where:
CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).
S = Limestone or other sorbent used in the reporting year (metric tons).
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas.
MW_{CO_2} = Molecular weight of carbon dioxide (44).
MW_S = Molecular weight of sorbent (100, if calcium carbonate).

(2) The total annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) *Biogenic CO_2 emissions.* If any fuel combusted in the unit meet the definition of biomass or biomass-derived fuel in § 98.6, then the owner or operator shall estimate and report the total annual biogenic CO_2 emissions, according to paragraph (e)(1), (2), (3), or (4) of this section, as applicable.

(1) The owner or operator may use Equation C–1 of this section to calculate the annual CO_2 mass emissions from the combustion of biogenic fuel, for a unit of any size, provided that:

(i) The Tier 4 calculation methodology is not required or elected.

(ii) The biogenic fuel consists of wood, wood waste, or other biomass-derived solid fuels (except for MSW).

(2) If CEMS are used to determine the total annual CO_2 emissions, either according to part 75 of this chapter or the Tier 4 Calculation Methodology of this section and if both fossil fuel and biogenic fuel (except for MSW) are combusted in the unit during the reporting year, use the following procedure to determine the annual biogenic CO_2 mass emissions. If MSW is combusted in the unit, follow the procedures in paragraph (e)(3) of this section:

(i) For each operating hour, use Equation C–12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:
V_{CO2h} = Hourly volume of CO_2 emitted (scf).
$(\%CO_2)_h$ = Hourly CO_2 concentration, measured by the CO_2 concentration monitor ($\%CO_2$).
Q_h = Hourly stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).
t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).
100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO_2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C–13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C–13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * GCV}{10^6} \qquad \text{(Eq. C-13)}$$

Where:
V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).
Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).
F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter or a site-specific value determined under section 3.3.6 of appendix F to part 75 of this chapter (scf CO_2/mmBtu).
GCV = Gross calorific value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel).
10 ^{6} = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biogenic fuels.

(v) Calculate the biogenic percentage of the annual CO_2 emissions, using Equation C–14 of this section:

$$\% \ Biogenic = \frac{V_{bio}}{V_{total}} \, x \, 100 \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the percent Biogenic obtained from Equation C–14 of this section of this section by the total annual CO_2 mass emissions in metric tons, as determined under paragraph (a)(1)(iv) of this section.

(3) For a unit that combusts MSW, the owner or operator shall use, for each quarter, ASTM Methods D 6866–06a and D 7459–08, as described in § 98.34(f), to determine the relative proportions of biogenic and non-biogenic CO_2 emissions when MSW is combusted. The results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 from MSW combustion is biogenic), and the quarterly values shall be averaged over the reporting year. The annual biogenic CO_2 emissions shall be calculated as follows:

(i) If the unit qualifies for the Tier 2 or Tier 3 Calculation Methodology of this section and the owner or operator elects to use the Tier 2 or Tier 3 Calculation Methodology to quantify GHG emissions:

(A) Use Equations C–2a, C–2b and C–3 of this section, as applicable, to calculate the annual CO_2 mass emissions from MSW combustion and from any auxiliary fuels such as natural gas. Sum these values, to obtain the total annual CO_2 mass emissions from the unit.

(B) Determine the annual biogenic CO_2 mass emissions from MSW combustion as follows. Multiply the total annual CO_2 mass emissions from MSW combustion by the biogenic decimal fraction obtained from ASTM Methods D 6866–06a and D 7459–08.

(ii) If the unit uses CEMS to quantify CO_2 emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V_{total}.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V_{ff}.

(C) Subtract V_{ff} from V_{total}, to obtain V_{MSW}, the total annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion by the biogenic decimal fraction obtained from ASTM Methods D 6866–06a and D 7459–08.

(E) Calculate the biogenic percentage of the total annual CO_2 emissions from the unit, using Equation C–14 of this section. For the purposes of this calculation, the term ‘‘V_{bio}’’ in the numerator of Equation C–14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e)(2)(vi) of this section.

(4) For biogas combustion, the Tier 2 or Tier 3 Calculation Methodology shall be used to determine the annual biogenic CO_2 mass emissions, except as provided in paragraph (e)(2) of this section.

§ 98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary combustion units shall be quality-assured as follows:

(a) For units using the calculation methodologies described in this paragraph, the records required under § 98.3(g) shall include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies described in § 98.33(a) are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology in § 98.33(a)(3) is used.

(3) Fossil fuel consumption, when, pursuant to § 98.33(e), the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(4) Sorbent usage, if the methodology in § 98.33(d) is used to calculate CO_2 emissions from sorbent.

(b) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage and sorbent usage (as applicable) in paragraph (a) of this section, including, but not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(c) For the Tier 2 Calculation Methodology, the applicable fuel sampling and analysis methods incorporated by reference in § 98.7 shall be used to determine the high heat values. For coal, the samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed. The minimum frequency of the sampling and analysis for each type of fuel (only for the weeks or months when that fuel is combusted in the unit) is as follows:

(1) Monthly, for natural gas, biogas, fuel oil, and other liquid fuels.

(2) For coal and other solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly.

(d) For the Tier 3 Calculation Methodology:

(1) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this part, using an applicable flow meter test method listed in § 98.7 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(2) Oil tank drop measurements (if applicable) shall be performed according to one of the methods listed in § 98.7.

(3) The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly. For other gaseous fuels (e.g., refinery gas, or process gas), daily sampling and analysis is required to determine the carbon content and molecular weight of the fuel. An applicable method listed in § 98.7 shall be used to determine the carbon content and (if applicable) molecular weight of the fuel.

(e) For the Tier 4 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in § 98.33(b)(6).

(1) For initial certification, use the following procedures:

(i) Section 75.20(c)(2) and (4) and appendix A to part 75) of this chapter.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to

part 60 of this chapter is selected for on-going quality assurance, perform daily calibration drift (CD) assessments for both the CO_2 and flow rate monitors, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(f) When municipal solid waste (MSW) is combusted in a unit, the biogenic portion of the CO_2 emissions from MSW combustion shall be determined using ASTM D6866–06a and ASTM D7459–08. The ASTM D6866–06a analysis shall be performed at least once in every calendar quarter in which MSW is combusted in the unit. Each gas sample shall be taken using ASTM D7459–08, during normal unit operating conditions while MSW is the only fuel being combusted, for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866–06a. The owner or operator shall separate total CO_2 emissions from MSW combustion in to biogenic emissions and non-biogenic emissions, using the average proportion of biogenic emissions of all samples analyzed during the reporting year. If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

§ 98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, the applicable missing data substitution procedures in part 75 of this chapter shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, gross calorific value (GCV), and fuel carbon content.

(b) For all units that are not subject to the requirements of the Acid Rain Program, when the Tier 1, Tier 2, Tier 3, or Tier 4 calculation is used, perform missing data substitution as follows for each parameter:

(1) For each missing value of the heat content, carbon content, or molecular weight of the fuel, and for each missing value of CO_2 concentration and percent moisture, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of stack gas flow rate, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the flow rate, fuel usage, or sorbent consumption, based on all available process data (e.g., steam production, electrical load, and operating hours). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.36 Data reporting requirements.

(a) In addition to the facility-level information required under § 98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraph (b) and (c) of this section (as applicable) and the emissions verification data in paragraph (d) of this section.

(b) *Unit-level emissions data reporting.* Except where aggregation of unit-level information is permitted under paragraph (c) of this section, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr (boilers, combustion turbines, engines, and process heaters only).

(4) Each type of fuel combusted in the unit during the report year.

(5) The calculated CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(6) The method used to calculate the CO_2 emissions for each type of fuel combusted (e.g., part 75 of this chapter or the Tier 1 or Tier 2 calculation methodology)

(7) If applicable, indicate which one of the monitoring and reporting methodologies in part 75 of this chapter was used to quantify the CO_2 emissions (e.g., CEMS, appendix G, LME).

(8) The calculated CO_2 emissions from sorbent (if any), expressed in metric tons.

(9) The total GHG emissions from the unit for the reporting year, i.e., the sum of the CO_2, CH_4, and N_2O emissions for all fuel types, expressed in metric tons of CO_2e.

(c) *Reporting alternatives for stationary combustion units.* For stationary combustion units, the following reporting alternatives may be used to simplify the unit-level reporting required under paragraph (b) of this section:

(1) *Aggregation of small units.* If a facility contains two or more units (e.g., boilers or combustion turbines) that have a combined maximum rated heat input capacity of 250 mmBtu/hr or less, the owner or operator may report the combined emissions for the group of units in lieu of reporting separately the GHG emissions from the individual units, provided that the amount of each type of fuel combusted in the units in the group is accurately quantified. More than one such group of units may be defined at a facility, so long as the aggregate maximum rated heat input capacity of the units in the group does not exceed 250 mmBtu/hr. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix ‘‘GP’’.

(ii) The ID number of each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(iv) Each type of fuel combusted in the units during the reporting year.

(v) The calculated CO_2, CH_4, and N_2O mass emissions for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e.

(vi) The methodology used to calculate the CO_2 mass emissions for each type of fuel combusted in the units.

(vii) The calculated CO_2 mass emissions (if any) from sorbent.

(viii) The total GHG emissions from the group for the year, i.e., the sum of the CO_2, CH_4, and N_2O emissions across, all fuel types, expressed in metric tons of CO_2e.

(2) *Monitored common stack configurations.* When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack, if CEMS are used to continuously monitor CO_2 mass emissions at the common stack according to part 75 of this chapter or as described in the Tier 4 Calculation Methodology in § 98.33(a)(4), the owner or operator may report the combined emissions from the units sharing the

common stack, in lieu of reporting separately the GHG emissions from the individual units. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack ID number, beginning with the prefix ''CS''.

(ii) ID numbers of the units sharing the common stack.

(iii) Maximum rated heat input capacity of each unit sharing the common stack (mmBtu/hr).

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology used to calculate the CO_2 mass emissions (i.e., CEMS or the Tier 4 Calculation Methodology).

(vi) The total CO_2 mass emissions measured at the common stack for the year, expressed in metric tons of CO_2e.

(vii) The combined annual CH_4 and N_2O emissions from the units sharing the common stack, expressed in metric tons of each gas and in metric tons of CO_2e.

(A) If the monitoring is done according to part 75 of this chapter, use Equation C–8 of this subpart, where the term ''$(HI)_A$'' is the cumulative annual heat input measured at the common stack.

(B) For the Tier 4 calculation methodology, use Equation C–9, C–10a or C–10b of this subpart separately for each type of fuel combusted in the units during the year, and then sum the emissions for all fuel types.

(viii) The total GHG emissions for the year from the units that share the common stack, i.e., the sum of the CO_2, CH_4, and N_2O emissions, expressed in metric tons of CO_2e.

(3) *Common pipe configurations.* When two or more oil-fired or gas-fired stationary combustion units at a facility combust the same type of fuel and that fuel is fed to the individual units through a common supply line or pipe, the owner or operator may report the combined emissions from the units served by the common supply line, in lieu of reporting separately the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a calibrated fuel flow meter. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe ID number, beginning with the prefix ''CP''.

(ii) ID numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(iv) The type of fuel combusted in the units during the reporting year.

(v) The methodology used to calculate the CO_2 mass emissions.

(vi) The total CO_2 mass emissions from the units served by the common pipe for the reporting year, expressed in metric tons of CO_2e.

(vii) The combined annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) The total GHG emissions for the reporting year from the units served by the common pipe, i.e., the sum of the CO_2, CH_4, and N_2O emissions, expressed in metric tons of CO_2e.

(d) *Verification data.* The owner or operator shall report sufficient data and supplementary information to verify the reported GHG emissions.

(1) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, or Tier 4 Calculation Methodology in § 98.33(a)(4) to quantify CO_2 emissions, the following additional information shall be included in the GHG emissions report:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted during the reporting year, in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted during each month (except for MSW). Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The number of required high heat value determinations for each type of fuel for the reporting year (i.e., ''n'' in Equation C–2a of this subpart, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with § § 98.33(a)(2) and 98.34(c).

(C) For each month, the high heat value used in Equation C–2a of this subpart for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels.

(D) For each reported HHV, indicate whether it is an actual measured value or a substitute data value.

(E) Each method from § 98.7 used to determine the HHV for each type of fuel combusted.

(F) For MSW, the total quantity (i.e., lb) of steam produced from MSW combustion during the year, and ''B'', the ratio of the unit's maximum rate heat input capacity to its design rated steam output capacity, in mmBtu per lb of steam.

(iii) For the Tier 3 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted during each month or day (as applicable), in metric tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The number of required carbon content determinations for each type of fuel for the reporting year, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with §§ 98.33(a)(3) and 98.34(d).

(C) For each operating month or day, the carbon content (CC) value used in Equation C–3, C–4, or C–5 of this subpart (as applicable), expressed as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels.

(D) For gaseous fuel combustion, the molecular weight of the fuel used in Equation C–5 of this subpart, for each operating month or day, in kg per kg-mole.

(E) For each reported CC value, indicate whether it is an actual measured value or a substitute data value.

(F) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the fuel flow meters used to measure the amount of fuel combusted.

(G) For fuel oil combustion, each method from § 98.7 used to make tank drop measurements (if applicable).

(H) Each method from § 98.7 used to determine the CC for each type of fuel combusted.

(I) Each method from § 98.7 used to calibrate the fuel flow meters (if applicable).

(iv) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating days and the total number of source operating hours in the reporting year.

(B) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program have been selected.

(C) The CO_2 emissions on each operating day, i.e., the sum of the hourly values calculated from Equation C–6 or C–7 (as applicable), in metric tons.

(D) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the number of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(E) The dates and results of the initial certification tests of the CEMS, and

(F) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(v) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in metric tons.

(B) The molecular weight of the sorbent.

(C) The ratio (''R'') in Equation C–11 of this subpart.

(vi) When ASTM methods D7459–08 and D6866–06a are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, as described in §§ 98.33(e) and 98.34(f), the owner or operator shall report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction, e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30.

(B) The total quantity of MSW combusted during the reporting year, in short tons if the Tier 2 Calculation Methodology is used or in metric tons if the Tier 3 calculation methodology is used.

(vii) For units that combust both fossil fuel and biogenic fuel, when CEMS are used to quantify the annual CO_2 emissions, the owner or operator shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., V_{total}, in scf.

(B) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., V_{ff}, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 emitted from the combustion of biogenic fuels, i.e., V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C–14 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(E) The annual average GCV value used in Equation C–14 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) The total annual biogenic CO_2 mass emissions, in metric tons.

(2) Within 7 days of receipt of a written request (e.g., a request by electronic mail) from the Administrator or from the applicable State or local air pollution control agency, the owner or operator shall submit the explanations described in § 98.34(a) and (b), as follows:

(i) A detailed explanation of how company records are used to quantify fuel consumption, if Calculation Methodology Tier 1 or Tier 2 of this subpart is used to calculate CO_2 emissions.

(ii) A detailed explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology in § 98.33(a)(3) is used to calculate CO_2 emissions.

(iii) A detailed explanation of how sorbent usage is quantified, if the methodology in § 98.33(d) is used to calculate CO_2 emissions from sorbent.

(iv) A detailed explanation of how company records are used to quantify fossil fuel consumption, when, as described in § 98.33(e), the owner or operator of a unit that combusts both fossil fuel and biogenic fuel uses CEMS to quantify CO_2 emissions.

§ 98.37 Records that must be retained.

The recordkeeping requirements of § 98.3(g) and, if applicable, § 98.34(a) and (b) shall be fully met for affected facilities with stationary combustion sources. Also, the records required under § 98.35(a)(1), documenting the data substitution procedures for missing stack flow rate, fuel flow rate, fuel usage and (if applicable) sorbent usage information and site-specific source testing (as allowed in § 98.33(c)(4)), shall be retained. No special recordkeeping beyond that specified in §§ 98.3, 98.35(a)(4), and 98.34(a) and (b) is required. All required records must be retained for a period of five years.

§ 98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE C–1 OF SUBPART C—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and Coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Sub-bituminous	17.25	97.02
Lignite	14.21	96.36
Unspecified (Residential/Commercial)	22.24	95.26
Unspecified (Industrial Coking)	26.28	93.65
Unspecified (Other Industrial)	22.18	93.91
Unspecified (Electric Power)	19.97	94.38.
Coke	24.80	102.04
Natural Gas	mmBtu/scf	kg CO_2/mmBtu.
Unspecified (Weighted U.S. Average)	1.027 x 10^{-3}	53.02
Petroleum Products	mmBtu/gallon	kg CO_2/mmBtu
Asphalt & Road Oil	0.158	75.55
Aviation gasoline	0.120	69.14
Distillate Fuel Oil (# 1, 2, & 4)	0.139	73.10
Jet Fuel	0.135	70.83
Kerosene	0.135	72.25
LPG (energy use)	0.092	62.98

TABLE C–1 OF SUBPART C—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO_2 emission factor
Propane	0.091	63.02
Ethane	0.069	59.54
Isobutane	0.099	65.04
n-Butane	0.103	64.93
Lubricants	0.144	74.16
Motor Gasoline	0.124	70.83
Residual Fuel Oil (# 5 & 6)	0.150	78.74
Crude Oil	0.138	74.49
Naphtha (< 401 deg. F)	0.125	66.46
Natural Gasoline	0.110	66.83
Other Oil (> 401 deg. F)	0.139	73.10
Pentanes Plus	0.110	66.83
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.04
Special Naphtha	0.125	72.77
Unfinished Oils	0.139	74.49
Waxes	0.132	72.58
Biomass-derived Fuels (solid)	mmBtu/short Ton	kg CO_2/mmBtu
Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels	15.38	93.80
Biomass-derived Fuels (Gas)	mmBtu/scf	kg CO_2/mmBtu
Biogas	Varies	52.07

Note: Heat content factors are based on higher heating values (HHV). Also, for petroleum products, the default heat content values have been converted from units of mmBtu per barrel to mmBtu per gallon.

TABLE C–2 OF SUBPART C—DEFAULT CO_2 EMISSION FACTORS FOR THE COMBUSTION OF ALTERNATIVE FUELS

Fuel type	Default CO_2 emission factor (kg CO_2/mmBtu)
Waste Oil	74
Tires	85
Plastics	75
Solvents	74
Impregnated Saw Dust	75
Other Fossil based wastes	80
Dried Sewage Sludge	110
Mixed Industrial waste	83
Municipal Solid Waste	90.652

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

TABLE C–3 OF SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Asphalt	3.0×10^{-3}	6.0×10^{-4}
Aviation Gasoline	3.0×10^{-3}	6.0×10^{-4}
Coal	1.0×10^{-2}	1.5×10^{-3}
Crude Oil	3.0×10^{-3}	6.0×10^{-4}
Digester Gas	9.0×10^{-4}	1.0×10^{-4}
Distillate	3.0×10^{-3}	6.0×10^{-4}
Gasoline	3.0×10^{-3}	6.0×10^{-4}
Jet Fuel	3.0×10^{-3}	6.0×10^{-4}
Kerosene	3.0×10^{-3}	6.0×10^{-4}
Landfill Gas	9.0×10^{-4}	1.0×10^{-4}
LPG	1.0×10^{-3}	1.0×10^{-4}
Lubricants	3.0×10^{-3}	6.0×10^{-4}
Municipal Solid Waste	3.0×10^{-2}	4.0×10^{-3}
Naphtha	3.0×10^{-3}	6.0×10^{-4}
Natural Gas	9.0×10^{-4}	1.0×10^{-4}
Natural Gas Liquids	3.0×10^{-3}	6.0×10^{-4}
Other Biomass	3.0×10^{-2}	4.0×10^{-3}

TABLE C–3 OF SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Petroleum Coke	3.0×10^{-3}	6.0×10^{-4}
Propane	1.0×10^{-3}	1.0×10^{-4}
Refinery Gas	9.0×10^{-4}	1.0×10^{-4}
Residual Fuel Oil	3.0×10^{-3}	6.0×10^{-4}
Tites	3.0×10^{-3}	6.0×10^{-4}
Waste Oil	3.0×10^{-2}	4.0×10^{-3}
Waxes	3.0×10^{-3}	6.0×10^{-4}
Wood and Wood Waste	3.0×10^{-2}	4.0×10^{-3}

Note: Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the ''Energy Industry'' or ''Manufacturing Industries and Construction''. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC ''Energy Industry'' category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises all facilities with one or more electricity generating units, including electricity generating units that are subject to the requirements of the Acid Rain Program.

(b) This source category does not include portable equipment or generating units designated as emergency generators in a permit issued by a State or local air pollution control agency.

§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.42 GHGs to report.

The annual mass emissions of CO_2, N_2O, and CH_4 shall be reported for each electricity generating unit.

§ 98.43 Calculating GHG emissions.

(a) For each electricity generating unit subject to the requirements of the Acid Rain Program, the owner or operator shall continue to monitor and report CO_2 mass emissions as required under §§ 75.13 and 75.64 of this chapter. CO_2 emissions for the purposes of the GHG emissions reports required under §§ 98.3 and 98.36 shall be calculated as follows:

(1) The owner or operator shall convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under § 75.64 of this chapter from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(2) The annual CH_4 and N_2O mass emissions shall be calculated using the methods specified in § 98.33 for stationary fuel combustion units.

(b) For each unit that is not subject to the reporting requirements of the Acid Rain Program, the annual CO_2, CH_4, and N_2O mass emissions shall be calculated using the methods specified in § 98.33 for stationary fuel combustion units.

§ 98.44 Monitoring and QA/QC requirements.

(a) For electricity generation units subject to the requirements of the Acid Rain Program, the CO_2 emissions data shall be quality assured according to the applicable procedures in appendices B, D, and G to part 75 of this chapter.

(b) For electricity generating units that are not subject to the requirements of the Acid Rain Program, the quality assurance and quality control procedures specified in § 98.34 for stationary fuel combustion units shall be followed.

§ 98.45 Procedures for estimating missing data.

(a) For electricity generation units subject to the requirements of the Acid Rain Program, the applicable missing data substitution procedures in part 75 of this chapter shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, gross calorific value (GCV), and fuel carbon content.

(b) For each electricity generating unit that is not subject to the requirements of the Acid Rain Program, the missing data substitution procedures specified in § 98.35 for stationary fuel combustion units shall be implemented.

§ 98.46 Data reporting requirements.

(a) For electricity generation units subject to the requirements of the Acid Rain Program, the owner or operator of a facility containing one or more electricity generating units shall meet the data reporting requirements specified in § 98.36(b) and, if applicable, § 98.36(c)(2) or (3).

(b) For electricity generating units not subject to the requirements of the Acid Rain Program, the owner or operator of a facility containing one or more electricity generating units shall meet the data reporting and verification requirements specified in § 98.36.

§ 98.47 Records that must be retained.

The owner or operator of a facility containing one or more electricity generating units shall meet the recordkeeping requirements of § 98.3(g) and, if applicable, § 98.37.

§ 98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§ 98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ 98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.52 GHGs to report.

(a) You must report N_2O process emissions from adipic acid production as required by this subpart.

(b) You must report CO_2, CH_4, and N_2O emissions from each stationary combustion unit that uses a carbon-based fuel, following the requirements of subpart C of this part.

§ 98.53 Calculating GHG emissions.

You must determine annual N_2O emissions from adipic acid production using a facility-specific emission factor according to paragraphs (a) through (e) of this section.

(a) You must conduct an annual performance test to measure N_2O emissions from the waste gas streams of each adipic acid oxidation process. You must conduct the performance test under normal process operating conditions.

(b) You must conduct the emissions test using the methods specified in § 98.54(b).

(c) You must measure the adipic acid production rate for the facility during the test and calculate the production rate for the test period in metric tons per hour.

(d) You must calculate an average facility-specific emission factor according to Equation E–1 of this section:

$$EF_{N2O} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. E-1)}$$

Where:

EF_{N_2O} = Average facility-specific N_2O emissions factor (lb N_2O/ton adipic acid produced).

C_{N_2O} = N_2O concentration during performance test (ppm N_2O).

$1.14x10^{-7}$ = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas (dscf/hr).

P = Production rate during performance test (tons adipic acid produced/hr).

n = Number of test runs.

(e) You must calculate annual adipic acid production process emissions of N_2O for the facility by multiplying the emissions factor by the total annual adipic acid production at the facility, according to Equation E–2 of this section:

$$E_{N_2O} = \frac{EF_{N_2O} * P_a * (1 - DF_N) * AF_N}{2205} \qquad \text{(Eq. E-2)}$$

Where:

E_{N_2O} = N_2O mass emissions per year (metric tons of N_2O).

EF_{N_2O} = Facility-specific N_2O emission factor (lb N_2O/ton adipic acid produced).

P_a = Total production for the year (ton adipic acid produced).

DF_N = Destruction factor of N_2O abatement technology (abatement device manufacturer's specified destruction efficiency, percent of N_2O removed from air stream).

AF_N = Abatement factor of N_2O abatement technology (percent of year that abatement technology was used).

2205 = Conversion factor (lb/metric ton).

§ 98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor at least annually. You must also conduct a new performance test whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test. The new emissions factor may be calculated using all available performance test data (i.e., average with the data from previous years), except in cases where process modifications have occurred or operating conditions have changed. Only the data consistent with the reporting period after the changes were implemented shall be used.

(b) You must conduct each emissions test using EPA Method 320 in 40 CFR part 63, Appendix A or ASTM D6348–03 (incorporated by reference—see § 98.7) to measure the N_2O concentration in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each.

(c) Each facility must conduct all required performance tests according to a test plan and EPA Method 320 in 40 CFR part 63, appendix A or ASTM D6348–03 (incorporated by reference-see § 98.7). All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(1) through (3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate during the test and how it was determined. The production rate can be determined through sales records, or through direct measurement using flow meters or weigh scales.

§ 98.55 Procedures for estimating missing data.

Procedures for estimating missing data are not provided for N_2O process emissions for adipic acid production facilities calculated according to § 98.53. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 98.56 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (h) of this section for each adipic acid production facility:

(a) Annual N_2O emissions from adipic acid production in metric tons.

(b) Annual adipic acid production capacity (in metric tons).

(c) Annual adipic acid production, in units of metric tons of adipic acid produced.

(d) Number of facility operating hours in calendar year.

(e) Emission rate factor used (lb N_2O/ton adipic acid).

(f) Abatement technology used (if applicable).

(g) Abatement technology efficiency (percent destruction).

(h) Abatement utilization factor (percent of time that abatement system is operating).

§ 98.57 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (f) of this section at the facility level:

(a) Annual N_2O emissions from adipic acid production, in metric tons.

(b) Annual adipic acid production capacity, in metric tons.

(c) Annual adipic acid production, in units of metric tons of adipic acid produced.

(d) Number of facility operating hours in calendar year.

(e) Measurements, records and calculations used to determine the annual production rate.

(f) Emission rate factor used and supporting test or calculation information including the annual emission rate factor determination report specified in § 98.54(c). This report must be available upon request.

§ 98.58 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart F—Aluminum Production

§ 98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§ 98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.62 GHGs to report.

You must report:

(a) Total perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electrolysis cells.

(b) Total CO_2 emissions from anode consumpton during electrolysis in all prebake and Søderberg electrolysis cells.

(c) Total CO_2 emissions from anode baking for all prebake cells.

(d) For CO_2, N_2O, and CH_4 emissions from stationary fuel combustion units, you must follow the requirements in subpart C of this part.

§ 98.63 Calculating GHG emissions.

(a) Use Equation F–1 of this section to estimate CF_4 emissions from anode effects, and use Equation F–2 to estimate C_2F_6 emissions from anode effects from each prebake and Søderberg electrolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \qquad \text{(Eq. F-1)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

S_{CF4} = The slope coefficient ((kg CF_4/metric ton Al)/(AE-Mins/cell-day)).

AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).

MP = Metal production (metric tons Al). where AEM and MP are calculated monthly.

$$E_{C2F6} = E_{CF4} \times F_{C2F6/CF4} \times 0.001 \qquad \text{(Eq. F-2)}$$

Where:

E_{C2F6} = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).

E_{CF4} = CF_4 emissions from aluminum production (kg CF_4).

$F_{C2F6/CF4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

0.001 = Conversion factor from kg to metric tons, where E_{CF4} is calculated monthly.

(b) Use the following procedures to calculate CO_2 emissions from anode consumption during electrolysis:

(1) For Prebake cells: You must calculate CO_2 emissions from anode consumption using Equation F–3 of this section:

$$E_{CO2} = NAC \times MP \times \left(\left[100 - S_a - Ash_a \right] / 100 \right) \times (44/12) \qquad \text{(Eq. F-3)}$$

Where:

ECO_2 = Annual CO_2 emissions from prebaked anode consumption (metric tons CO_2).

NAC = Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).

MP = Total annual metal production (metric tons Al).

S_a = Sulfur content in baked anode (percent weight).

Ash_a = Ash content in baked anode (percent weight).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) For Søderberg cells you must calculate CO_2 emissions using Equation F–4 of this section:

$$\begin{gathered} E_{CO2} = (PC \text{ x } MP - \left[CSM \text{ x } MP \right] / 1000 - BC/100 \times PC \times \\ MP \times \left[S_p + Ash_p + H_p \right] / 100 - \left[100 - BC \right] / 100 \times PC \times MP \times \qquad \text{(Eq. F-4)} \\ \left[S_c + Ash_c \right] / 100 - MP \times CD \times (44/12) \end{gathered}$$

Where:

E_{CO2} = Annual CO_2 emissions from paste consumption (metric ton CO_2).

PC = Annual paste consumption (metric ton/metric ton Al).

MP = Total annual metal production (metric ton Al).

CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).

BC = Binder content of paste (percent weight).

S_p = Sulfur content of pitch (percent weight).

Ash_p = Ash content of pitch (percent weight).

H_p = Hydrogen content of pitch (percent weight).

S_c = Sulfur content in calcined coke (percent weight).

Ash_c = Ash content in calcined coke (percent weight).

CD = Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(c) Use the following procedures to calculate CO_2 emissions from anode baking of prebake cells:

(1) Use Equation F–5 of this section to calculate emissions from pitch volatiles.

$$E_{CO2PV} = (GA - H_w - BA - WT) \times (44/12) \qquad \text{(Eq. F-5)}$$

Where:

E_{CO2PV} = Annual CO_2 emissions from pitch volatiles combustion (metric tons CO_2).
GA = Initial weight of green anodes (metric tons).
H_w = Annual hydrogen content in green anodes (metric tons).
BA = Annual baked anode production (metric tons).
WT = Annual waste tar collected (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation F–6 of this section to calculate emissions from bake furnace packing material.

$$E_{CO2PC} = PCC \times BA \times \left(\left[100 - S_{pc} - Ash_{pc}\right]/100\right) \times (44/12) \qquad \text{(Eq. F-6)}$$

Where:

E_{CO2PC} = Annual CO_2 emissions from bake furnace packing material (metric tons CO_2).
PCC = Annual packing coke consumption (metric tons/metric ton baked anode).
BA = Annual baked anode production (metric tons).
S_{pc} = Sulfur content in packing coke (percent weight).
Ash_{pc} = Ash content in packing coke (percent weight).
44/12 = Ratio of molecular weights, CO_2 to carbon.

§ 98.64 Monitoring and QA/QC requirements.

(a) The smelter-specific slope coefficient must be measured at least every 36 months in accordance with the EPA/IAI Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production (2008).

(b) The minimum frequency of the measurement and analysis is annually except as follows: Monthly—anode effect minutes per cell day, production.

(c) Sources may use smelter-specific values from annual measurements of parameters needed to complete the equations in § 98.63 (e.g., sulfur, ash, and hydrogen contents), or may use default values from Volume III, Section 4.4, in Chapter 4, of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

§ 98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO_2 emissions can be estimated from aluminum production using Tier 1 method per Equation F–7 of this section.

$$ECO_2 = EF_p \text{ x } MP_p + EF_s \text{ x } MP_s \qquad \text{(Eq. F-7)}$$

Where:

ECO_2 = CO_2 emissions from anode and/or paste consumption, tonnes CO_2.
EF_p = Prebake technology specific emission factor (1.6 tonnes CO_2/tonne aluminum produced).
MP_p = Metal production from prebake process (tonnes Al).
EF_s = Søderberg technology specific emission factor (1.7 tonnes CO_2/tonne Al produced).
MP_s = Metal production from Søderberg process (tonnes Al).

(b) For other parameters, use the average of the two most recent data points.

§ 98.66 Data reporting requirements.

In addition to the information required by § 98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electolysis cells combined.

(2) Anode effect minutes per cell-day, anode effect frequency (AE/cell-day), anode effect duration (minutes).

(3) Smelter-specific slope coefficient and the last date when the smelter-specific-slope coefficient was measured.

(d) Method used to measure the frequency and duration of anode effects.

(e) The following CO_2-specific information for prebake cells on an annual basis:

(1) Total anode consumption.

(2) Total CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells on an annual basis:

(1) Total paste consumption.

(2) Total CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg).

§ 98.67 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in each prebake and Søderberg electolysis cells.

(2) Anode effect minutes per cell-day, anode effect frequency (AE/cell-day), anode effect duration (minutes) from each prebake and Søderberg electolysis cells.

(3) Smelter-specific slope coefficient and the last date when the smelter-specific-slope coefficient was measured.

(d) Method used to measure the frequency and duration of anode effects.

(e) The following CO_2-specific information for prebake cells on an annual basis:

(1) Total anode consumption.

(2) Total CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells on an annual basis:

(1) Total paste consumption.

(2) Total CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg).

§ 98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart G—Ammonia Manufacturing

§ 98.70 Definition of source category.

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid raw material.

§ 98.71 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an ammonia manufacturing process and the facility meets the requirements of either § *98.2(a)(1) or (2).*

§ 98.72 GHGs to report.

You must report:

(a) Carbon dioxide (CO_2) process emissions from steam reforming of a hydrocarbon or the gasification of solid raw material, reported for each ammonia manufacturing process unit.

(b) CO_2, N_2O, and CH_4 emissions from fuel combustion at ammonia manufacturing processes and any other stationary fuel combustion units. You must follow the requirements of 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources).

(c) For CO_2 collected and used on site or transferred off site, you must follow the requirements of subpart PP (Suppliers of CO_2) of this part.

§ 98.73 Calculating GHG emissions.

You must determine CO_2 process emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) Any ammonia manufacturing process unit that meets the conditions specifed in § 98.33(b)(5)(iii)(A), (B), and (C), or § 98.33(b)(5)(ii)(A) through (F) shall calculate total CO_2 emissions using a continuous emissions monitoring system according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If the facility does not measure total emissions with a CEMS, you must calculate the annual CO_2 process emissions from feedstock used for ammonia manufacturing.

(1) *Gaseous feedstock.* You must calculate the total CO_2 process emissions from gaseous feedstock according to Equation G–1 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} \frac{44}{12} * \left(\mathrm{Fdstk}\right)_n * (\mathrm{CC})_n * \frac{\mathrm{MW}}{\mathrm{MVC}} \right) * 0.001 \qquad \text{(Eq. G-1)}$$

Where:

CO_2 = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$(\mathrm{Fdstk})_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

$(\mathrm{CC})_n$ = Average carbon content of the gaseous feedstock, from the analysis results for month n (kg C per kg of feedstock).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(2) *Liquid feedstock.* You must calculate the total CO_2 process emissions from liquid feedstock according to Equation G–2 of this section:

$$CO_2 = \left(v \sum_{n=1}^{12} \frac{44}{12} * \left(\mathrm{Fdstk}\right)_n * (\mathrm{CC})_n \right) * 0.001 \qquad \text{(Eq. G-2)}$$

Where:

CO_2 = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$(\mathrm{Fdstk})_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

$(\mathrm{CC})_n$ = Average carbon content of the liquid feedstock, from the analysis results for month n (kg C per gallon of feedstock).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

$(R_{CO_2})n$ = CO_2 captured or recovered for use in urea or methanol production for month n, kg CO_2.

(3) *Solid feedstock.* You must calculate the total CO_2 process emissions from solid feedstock according to Equation G–3 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} \frac{44}{12} * \left(\mathrm{Fdstk}\right)_n * (\mathrm{CC})_n \right) * 0.001 \qquad \text{(Eq. G-3)}$$

Where:

CO_2 = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$(Fdstk)_n$ = Mass of the solid feedstock used in month n (kg of feedstock).

$(CC)_n$ = Average carbon content of the solid feedstock, from the analysis results for month n (kg C per kg of feedstock).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

$(R_{CO_2})_n$ = CO_2 captured or recovered for use in urea or methanol production for month n, kg CO_2.

§ 98.74 Monitoring and QA/QC requirements.

(a) Facilities must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must collect a sample of each feedstock on a monthly basis and analyze the carbon content using any suitable method incorporated by reference in § 98.7.

(c) All fuel flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(d) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

§ 98.75 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraphs (a) and (b) of this section.

(a) For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure.

(b) There are no missing data procedures for carbon content. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c) of subpart A of this part, each annual report must contain the information specified in paragraphs (a) through (c) for each ammonia manufacturing process unit:

(a) Annual CO_2 process emissions (metric tons).

(b) Total quantity of feedstock consumed for ammonia manufacturing.

(c) Monthly analyses of carbon content for each feedstock used in ammonia manufacturing (kg carbon/kg of feedstock).

§ 98.77 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section.

(a) Method used for determining quantity of feedstock used.

(b) Monthly analyses of carbon content for each feedstock used in ammonia manufacturing.

§ 98.78 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart H—Cement Production

§ 98.80 Definition of the source category.

The cement production source category consists of each kiln and each in-line kiln/raw mill at any portland cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/raw mills that burn hazardous waste.

§ 98.81 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a cement production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.82 GHGs to report.

Carbon dioxide (CO_2) process emissions from calcination, reported for all kilns combined.

CO_2, N_2O, and CH_4 emissions from fuel combustion at each kiln and any other stationary combustion units, by following the requirements of 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources).

§ 98.83 Calculating GHG emissions.

(a) Cement kilns that meet the conditions specified in § 98.33(b)(5)(ii) or (iii) shall calculate total CO_2 emissions using the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If CEMS are not used to determine the total annual CO_2 emissions from kilns, then you must calculate process CO_2 emissions by following paragraphs (b)(1) through (3) of this section.

(1) Calculate CO_2 process emissions from all kilns at the facility using Equation H–1 of this section:

$$CO_{2\ CMF} = \sum_{m=1}^{k} CO_{2\ cli,m} + CO_{2\ rm} \qquad \text{(Eq. H-1)}$$

Where:

$CO_{2\ CMF}$ = Total annual emissions of CO_2 from cement manufacturing, metric tons.

$CO_{2\ Cli,m}$ = Total annual emissions of CO_2 from clinker production from kiln m, metric tons.

$CO_{2\ rm}$ = Total annual emissions of CO_2 from raw materials, metric tons.

k = Total number of kilns at a cement manufacturing facility.

(2) CO_2 emissions from clinker production. Calculate CO_2 emissions from each kiln using Equations H–2 and H–3 of this section.

$$CO_2\ cli,m = \sum_{j=1}^{p}\Big[\left(Cli,_j\right)*\left(EFcli,_j\right)\Big] + \sum_{i=1}^{r}\Big[\left(CKD,_i\right)*\left(EFCKD,_i\right)\Big] \qquad \text{(Eq. H-2)}$$

Where:

$Cli_{,j}$ = Quantity of clinker produced in month j from kiln m, metric tons.

$EF_{Cli,j}$ = Kiln specific clinker emission factor for month j for kiln m, metric tons CO_2/metric ton clinker computed as specified in Equation H–3 of this section.

CKD_i = Cement kiln dust (CKD) discarded in quarter i from kiln m, metric tons.

$EF_{CKD,i}$ = Kiln specific fraction of calcined material in CKD not recycled to the kiln, for quarter i from kiln m, as determined in paragraph (c)(2)(i).

p = Number of months for clinker calculation, 12.

r = Number of quarters for CKD calculation, 4.

$$EF_{Cli} = \left(CLi_{CaO} - Cli_{ncCaO}\right) * MR_{CaO} + \left(Cli_{MgO} - Cli_{ncMgO}\right) * MR_{MgO} \qquad \text{(Eq. H-3)}$$

Where:

Cli_{CaO} = Monthly CaO content of Clinker, wt% as determined in § 98.84(b).

MR_{CaO} = Molecular Ratio of CO_2/CaO = 0.785.

Cli_{MgO} = Monthly MgO content of Clinker, wt% as determined in § 98.84(b).

MR_{MgO} = Molecular Ratio of CO_2/MgO = 1.092.

Cli_{ncCaO} = Monthly non-carbonate CaO of Clinker, wt% as determined in § 98.84(b).

Cli_{ncMgO} = Monthly non-carbonate MgO of Clinker, wt% as determined in § 98.84(b).

(i) EF_{CKD} must be determined through X-ray fluorescence (XRF) test or other testing method specified in § 98.84(a), except as provided in paragraph (c)(2)(ii) of this section.

(ii) A default factor of 1.0, which assumes that 100 percent of all carbonates in CKD are calcined, may be used instead of testing to determine EF_{CKD}.

(iii) The weight percents of CaO, MgO, non-carbonate CaO, and non-carbonate MgO of clinker used in Equation H–3 must be determined using the measurement methods specified in § 98.84(b).

(3) *CO_2 emissions from raw materials.* Calculate CO_2 emissions using Equation H–4 of this section:

$$CO_{2\ rm} = rm\ *\ TOC_{rm}\ *\ 3.664 \qquad \text{(Eq. H-4)}$$

Where:

rm = The amount of raw material consumed annually, metric tons/yr.

TOC_{rm} = Organic carbon content of raw material, as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.

3.664 = The CO_2 to carbon molar ratio.

§ 98.84 Monitoring and QA/QC requirements.

(a) You must determine the plant-specific fraction of calcined material in cement kiln dust (CKD) not recycled to the kiln (EFCKD) using an x-ray fluorescence test or other enhanced testing method. The monitoring must be conducted quarterly for each kiln from a CKD sample drawn from bulk CKD storage.

(b) You must determine the weight percents of CaO, MgO, non-carbonate CaO, and non-carbonate MgO in clinker from each kiln using an x-ray fluorescence test or other enhanced testing method. The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(c) The total organic carbon contents of raw materials must be determined annually using ASTM Method C114–07 or a similar ASTM method approved for total organic carbon determination in raw mineral materials. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material (i.e. limestone, sand, shale, iron oxide, and alumina).

(d) The quantity of clinker produced monthly by each kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of CKD discarded quarterly by each kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(f) The quantity of each category of raw materials consumed annually by the facility (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ 98.85 Procedures for estimating missing data.

If the CEMS approach is used to determine CO_2 emissions, the missing data procedures in § 98.35 apply. Procedures for estimating missing data do not apply to CO_2 process emissions from cement manufacturing facilities calculated according to § 98.83(b). If data on the carbonate content or organic carbon content is missing, facilities must undertake a new analysis.

§ 98.86 Data reporting requirements.

In addition to the information required by § 98.3(b) of this part, each annual report must contain the information specified in paragraphs (a) through (k) of this section for each portland cement manufacturing facility.

(a) The total combined CO_2 emissions from all kilns at the facility (in metric tons).

(b) Annual clinker production (tons).

(c) Number of kilns.

(d) Annual CKD production (in metric tons).

(e) Total annual fraction of CKD recycled to the kilns (as a percentage).

(f) Annual weighted average carbonate composition (by carbonate).

(g) Annual weighted average fraction of calcination achieved (for each carbonate, percent).

(h) Site-specific emission factor (metric tons CO_2/metric ton clinker produced).

(i) Organic carbon content of the raw material (percent).

(j) Annual consumption of raw material (metric tons).

(k) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36(d)(iv).

§ 98.87 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (i) of this section for each portland cement manufacturing facility.

(a) Monthly carbonate consumption.

(b) Monthly clinker production (tons).

(c) Monthly CKD production (in metric tons).

(d) Total annual fraction of CKD recycled to the kiln (as a percentage).

(e) Monthly analysis of carbonate composition in clinker (by carbonate).

(f) Monthly analysis of fraction of calcination achieved for CKD and each carbonate.

(g) Monthly cement production.

(h) Documentation of calculated site-specific clinker emission factor.

(i) Facilities that use CEMS must also comply with the recordkeeping requirements specified in § 98.37.

§ 98.88 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart I—Electronics Manufacturing

§ 98.90 Definition of the source category.

(a) The electronics source category consists of any of the processes listed in paragraphs (a)(1) through (5) of this section. Electronics manufacturing facilities include but are not limited to facilities that manufacture semiconductors, liquid crystal displays (LCD), microelectromechanical systems (MEMs), and photovoltaic (PV) cells.

(1) Each electronics manufacturing production process in which the etching process uses plasma-generated fluorine atoms, which chemically react with exposed thin films (e.g., dielectric, metals) and silicon to selectively remove portions of material.

(2) Each electronics manufacturing production process in which chambers used for depositing thin films are cleaned periodically using plasma-generated fluorine atoms from fluorinated and other gases.

(3) Each electronics manufacturing production process in which some fluorinated compounds can be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere.

(4) Each electronics manufacturing production process in which the chemical vapor deposition process uses nitrous oxide.

(5) Each electronics manufacturing production process in which fluorinated GHGs are used as heat transfer fluids (HTFs) to cool process equipment, control temperature during device testing, and solder semiconductor devices to circuit boards.

§ 98.91 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an electronics manufacturing process and the facility meets the requirements of either § *98.2(a)(1) or (2).*

§ 98.92 GHGs to report.

(a) You shall report emissions of nitrous oxide and fluorinated GHGs (as defined in § 98.6). The fluorinated GHGs that are emitted from electronics production processes include but are not limited to those listed in Table I–1 of this subpart. You must report:

(1) Fluorinated GHGs from plasma etching.

(2) Fluorinated GHGs from chamber cleaning.

(3) Nitrous oxide from chemical vapor deposition.

(4) Fluorinated GHGs from heat transfer fluid use.

(b) You shall report CO_2, N_2O and CH_4 combustion-related emissions, if any, at electronics manufacturing facilities. For stationary fuel combustion sources, follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements in subpart C of this part.

§ 98.93 Calculating GHG emissions.

(a) You shall calculate annual facility-level F–GHG emissions of each F–GHG from all etching processes using Equations I–1 and I–2 of this section:

$$etchE_i = \sum_j E_{ij} \qquad \text{(Eq. I-1)}$$

Where:

$etchE_i$ = Annual emissions of input gas i from all etch processes

E_{ij} = Annual emissions of input gas i from etch process j (metric tons), calculated in equation I–5.

$$etchBE_k = \sum_j \sum_i BE_{kij} \qquad \text{(Eq. I-2)}$$

Where:

$etchBE_k$ = Annual emissions of by-product gas k from all etch processes (metric tons).

BE_{kij} = Annual emissions of by-product k formed from input gas i during etch process j (metric tons), calculated in equation I–6.

(b) You shall calculate annual facility-level F–GHG emissions of each F–GHG from all CVD chamber cleaning processes using Equations I–3 and I–4 of this section:

$$cleanE_i = \sum_j E_{ij} \qquad \text{(Eq. I-3)}$$

Where:

$cleanE_i$ = Annual emissions of input gas i from all CVD cleaning processes (metric tons).

E_{ij} = Annual emissions of input gas i from CVD cleaning process j (metric tons), calculated in equation I–5.

$$cleanBE_k = \sum_j \sum_i BE_{kij} \qquad \text{(Eq. I-4)}$$

Where:

$cleanBE_k$ = Annual emissions of by-product gas k from all CVD cleaning processes (metric tons)

BE_{kij} = Annual emissions of by-product k formed from input gas i during CVD cleaning process j (metric tons), calculated in equation I–6.

(c) You shall calculate annual facility-level F–GHG emissions for each etching process and each chamber cleaning process using Equations I–5 and I–6 of this section.

(1) Semiconductor facilities that have an annual capacity of greater than 10,500 m^2 silicon shall use process-specific process utilization and by-product formation factors determined as specified in § 98.94(b).

(2) All other electronics facilities shall use the default emission factors for process utilization and by-production formation shown in Tables I–2, I–3, and I–4 of subpart I for semiconductor and MEMs, LCD, and PV manufacturing, respectively.

$$E_{ij} = C_{ij} * \left(1 - U_{ij}\right) * \left(1 - a_{ij} * d_{ij}\right) * 0.001 \qquad \text{(Eq. I-5)}$$

Where:

E_{ij} = Annual emissions of input gas i from process j (metric tons).

C_{ij} = Amount of input gas i consumed in process j, (kg).

U_{ij} = Process utilization rate for input gas i during process j.

a_{ij} = Fraction of input gas i used in process j with abatement devices.

d_{ij} = Fraction of input gas i destroyed in abatement devices connected to process j (defined in Equation I–11). This is zero unless the facility verifies the DRE of the device pursuant to § 98.94(c) of Subpart I.

0.001 = Conversion factor from kg to metric tons.

$$BE_{ij} = B_{kij} * C_{ij} * \left(1 - a_{ij} * d_{kj}\right) \qquad \text{(Eq. I-6)}$$

Where:

BE_{kij} = Annual emissions of by-product k formed from input gas i during process j (metric tons).

B_{kij} = Kg of gas k created as a by-product per kg of input gas i consumed in process j.

C_{ij} = Amount of input gas i consumed in process j (kg).

a_{ij} = Fraction of input gas i used in process j with abatement devices.

d_{kj} = Fraction of by-product gas k destroyed in abatement devices connected to process (j). This is zero unless the facility verifies the DRE of the device pursuant to § 98.94(c) of Subpart I.

0.001 = Conversion factor from kg to metric tons.

(d) You shall report annual N_2O facility-level emissions during chemical vapor deposition using Equation I–7 of this section.

$$E\left(N_2O\right) = C_{N_2O}\ x\ 0.001 \qquad \text{(Eq. I-7)}$$

Where:

$E(N_2O)$ = Annual emissions of N_2O (metric tons/year).

C_{N_2O} = Annual Consumption of N_2O (kg).

0.001 = Conversion factor from kg to metric tons.

(e) For facilities that use heat transfer fluids, you shall report the annual emissions of fluorinated GHG heat transfer fluids using Equation I–8 of this section.

$$EH_i = density * \left[I_{io} + P_{it} - N_{it} + R_{it} - I_{it} - D_{it} * 0.001\right] \qquad \text{(Eq. I-8)}$$

Where:

EH_i = Emissions of fluorinated GHG heat transfer fluid i, (metric tons/year).

Density = Density of heat transfer fluid i (kg/l).

I_{io} = Inventory of heat transfer fluid i at the end of previous reporting period (l).

P_{it} = Net purchases of heat transfer fluid i during the current reporting period (l).

N_{it} = Total nameplate capacity [charge] of equipment that contains heat transfer fluid i and that is installed during the current reporting period.

R_{it} = Total nameplate capacity [charge] of equipment that contains heat transfer fluid i and that is retired during the current reporting period.

I_{it} = Inventory of heat transfer fluid i at the end of current reporting period (l).

D_{it} = Amount of heat transfer fluid i recovered and sent off site during current reporting period, (l).

0.001 = Conversion factor from kg to metric tons.

§ 98.94 Monitoring and QA/QC requirements.

(a) You must estimate gas consumption according to the requirements in paragraph (a)(1) or (a)(2) of this section for each process or process type, as appropriate.

(1) Monitor changes in container mass and inventories for each gas using weigh scales with an accuracy and precision of one percent of full scale or better. Calculate the gas consumption using Equation I–9 of this section.

$$C_i = I_{Bi} - I_{Ei} + A - D * 0.001 \qquad \text{(Eq. I-9)}$$

Where:

C_i = Annual consumption of input gas i (metric tons/year).

I_{Bi} = Inventory of input gas i stored in cylinders or other containers at the beginning of the year, including heels (kg).

I_{Ei} = Inventory of input gas i stored in cylinders or other containers at the end of the year, including heels (kg).

A = Acquisitions of that gas during the year through purchases or other transactions, including heels in cylinders or other containers returned to the electronics production facility (kg).

D = Disbursements of gas through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics production facility to the gas distributor (kg).

0.001 = Conversion factor from kg to metric tons.

(2) Monitor the mass flow of the pure gas into the system using flowmeters. The flowmeters must have an accuracy and precision of one percent of full scale or better.

(b) If you use fluorinated GHG utilization rates and by-product emission factors other than the defaults in Tables I–2, I–3, or I–4 of Subpart I, you must use fluorinated GHG utilization rates and by-product emission factors that have been measured using the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment. You may use fluorinated GHG utilization rates and by-product emission factors measured by manufacturing equipment suppliers if the conditions in paragraph (b)(1) and (2) of this section are met.

(1) The manufacturing equipment supplier has measured the GHG utilization rates and by-product emission factors using the International SEMATECH Guideline.

(2) The conditions under which the measurements were made are representative of your facility's F–GHG emitting processes.

(c) If your facility employs abatement devices and you wish to reflect the emission reductions due to these devices in § 98.93(c), you must verify the destruction or removal efficiency (DRE) of the devices using the methods in either paragraph (c)(1) or (2) of this section.

(1) Experimentally determine the effective dilution through the abatement device and measure abatement DRE during actual or simulated process conditions by following the procedures of this paragraph.

(i) Measure the concentrations of F–GHGs exiting the process tool and entering and exiting the abatement system under operating process and abatement system conditions that are representative of those for which F–GHG emissions are estimated and abatement-system DRE is used for the F–GHG reporting period.[1]

(ii) Measure the dilution through the abatement system and calculate the dilution factor under the representative operating conditions given in paragraph (c)(i) of this section by using the tracer method. This method consists of injecting known flows of a non-reactive gas (such as krypton) at the inlet of the abatement system, measuring the time-averaged concentrations of krypton entering ($[Kr]_{in}$) and exiting ($[Kr]_{out}$) the abatement system, and calculating the dilution factor (DF) as the ratio of the time-averaged measured krypton concentrations entering and exiting the abatement system, using equation I–10 of this section.

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[1] Abatement system means a point-of-use (POU) abatement system whereby a single abatement system is attached to a single process tool or single process chamber of a multi-chamber tool.

$$DF = \frac{[Kr]_{in}}{[Kr]_{out}} \qquad \text{(Eq. I-10)}$$

(iii) Measure the F–GHG concentrations in and out of the device with all process chambers connected to the F–GHG abatement system and under the production and abatement system conditions for which F–GHG emissions are estimated for the reporting period.[2]

(iv) Calculate abatement system DRE using Equation I–11 of this section, where it is assumed that the measurement pressure and temperature at the inlet and outlet of the abatement system are identical and where the relative precision (ε) of the quantity c_{i-out}*DF/c_{i-in} shall not exceed ±10 percent (two standard deviations) using proper statistical methods.

$$d_{ij} = 1 - \frac{DF * c_{i-out}}{c_{i-in}} \qquad \text{(Eq. I-11)}$$

Where:

d_{ij} = Destruction or removal efficiency (DRE)
c_{i-in} = Concentration of gas i in the inflow to the abatement system (ppm).
c_{i-out} = Concentration of gas i in the outflow from the abatement system (ppm).
DF = Dilution Factor calculated using Equation I–10.

(v) The DF may not be obtained by calculation from flows other than those obtained by using the tracer method described in paragraph (ii) of this section.

(2) Install abatement devices that have been tested by a third party (e.g., UL) according to EPA's Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing. This testing may be obtained by the manufacturer of the equipment.

(d) Abatement devices must be operated within the manufacturer's specified equipment lifetime and gas flow and mix limits and must be maintained according to the manufacturer's guidelines.

(e) You shall adhere to the QA/QC procedures of this paragraph when estimating F–GHG and N_2O emissions from cleaning/etching processes:

(1) You shall follow the QA/QC procedures in the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment when estimating facility-specific gas process utilization and by-product gas formation.

(2) You shall follow the QA/QC procedures in the EPA DRE measurement protocol when estimating abatement device DRE.

(3) You shall certify that abatement devices are maintained in accordance with manufacturer specified guidelines.

(4) You shall certify that gas consumption is tracked to a high degree of precision as part of normal facility operations and that further QA/QC is not required.

(f) You shall adhere to the QA/QC procedures of this paragraph when estimating F–GHG emissions from heat transfer fluid use:

(1) You shall review all inputs to Equation I–4 of this section to ensure that all inputs and outputs to the facility's system are accounted for.

(2) You shall not enter negative inputs into the mass balance Equation I–4 of this section and shall ensure that no negative emissions are calculated.

(3) You shall ensure that the beginning of year inventory matches the end of year inventory from previous year.

(g) All flowmeters, scales, load cells, and volumetric and density measures used to measure quantities that are to be reported under § 98.92 and § 98.96 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(h) All instruments (e.g., mass spectrometers and fourier transform infrared measuring systems) used to determine the concentration of fluorinated greenhouse gases in process streams shall be calibrated just prior to DRE, gas utilization, or product formation measurement through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

§ 98.95 Procedures for estimating missing data.

(a) For semiconductor facilities that have an annual capacity of greater than 10,500 m^2 silicon, you shall estimate missing site-specific gas process utilization and by-product formation using default factors from Tables I–2 through I–4 of this subpart. However, use of these default factors shall be restricted to less than 5 percent of the total facility emissions.

(b) For facilities using heat transfer fluids and missing data for one or more of the parameters in Equation I–8, you shall estimate heat transfer fluid emissions using the arithmetic average of the emission rates for the year immediately preceding the period of missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the heat transfer fluid supplier. You shall document the method used and values estimated for all missing data values.

(c) If the methods specified in paragraphs (a) and (b) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing (e.g., because the monitoring failure was linked to a process disturbance that is likely to have significantly increased the F–GHG emission rate), you shall develop a best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in paragraphs (a) and (b) of this section would lead to a significant under-or overestimate of the parameter.

§ 98.96 Data reporting requirements.

In addition to the information required by § 98.3(c), you shall include in each annual report the following information for each electronics manufacturer.

(a) Emissions of each GHG emitted from all plasma etching processes, all chamber cleaning, all chemical vapor deposition processes, and all heat transfer fluid use, respectively.

(b) The method, mass of input F–GHG gases, and emission factors used for estimating F–GHG emissions.

(c) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD).

(d) Factors used for gas process utilization and by-product formation, and the source and uncertainty for each factor.

(e) The verified DRE and its uncertainty for each abatement device used, if you have verified the DRE pursuant to § 98.94(c).

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[2] Most process tools have multiple chambers. For combustion-type abatement systems, the outlets of each chamber separately enter the destruction-reactor because premixing of certain gaseous mixtures may be conducive to fire or explosion. For the less-frequently used plasma-type POU abatement systems, there is one system per chamber.

(f) Fraction of each gas fed into each process type with abatement devices.

(g) Description of abatement devices, including the number of devices of each manufacturer and model.

(h) For heat transfer fluid emissions, inputs in the mass-balance Equation.

(i) Example calculations for F–GHG, N_2O, and heat transfer fluid emissions.

(j) Estimate of the overall uncertainty in the emissions estimate.

§ 98.97 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Data used to estimate emissions including all spreadsheets and copies of calculations used to estimate emissions.

(b) Documentation for the values used for GHG utilization rates and by-product emission factors, including documentation that these were measured using the the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment.

(c) The date and results of the initial and any subsequent tests of emission control device DRE, including the following information:

(1) Dated certification, by the technician who made the measurement, that the dilution factor was determined using the tracer method.

(2) Dated certification, by the technician who made the measurement, that the DRE was calculated using the formula given in § 98.94(c)(1)(iv).

(3) Documentation of the measured flows, concentrations and calculations used to calculate DF, relative precision (ε), and DRE.

(d) The date and results of the initial and any subsequent tests to determine process tool gas utilization and by-product formation factors.

(e) Abatement device calibration and maintenance records.

§ 98.98 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE I–1 OF SUBPART I—GHGS TYPICALLY USED BY THE ELECTRONICS INDUSTRY

Product type	F–GHGs Used during manufacture
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6, and HTFs (CF3-(O-CF(CF3)-CF2)n-(O-CF2)m-O-CF3, CnF2n+2, CnF2n+1(O)CmF2m+1, CnF2nO, (CnF2n+1)3N)

TABLE I–2 OF SUBPART I—DEFAULT EMISSION FACTORS FOR SEMICONDUCTOR AND MEMS MANUFACTURING

Process gases	Factors					
	Etch 1-Ui	CVD 1-Ui	Etch BCF_4	Etch BC_2F_6	CVD BCF_4	CVD BC_3F_8
CF_4	0.7	0.9	NA	NA	NA	NA
C_2F_6	0.4*	0.6	0.4*	NA	0.1	NA
CHF_3	0.4*	NA	0.07*	NA	NA	NA
CH_2F_2	0.06*	NA	0.08*	NA	NA	NA
C_3F_8	NA	0.4	NA	NA	0.1	NA
c-C_4F_8	0.2*	0.1	0.2	0.2	0.1	NA
NF_3	NA	0.02	NA	NA	† 0.02	NA
Remote NF_3	0.2	0.2	NA	NA	† 0.1	NA
SF_6	0.2	NA	NA	NA	NA	NA
C_4F_6[a]	0.1	NA	0.3*	0.2*	NA	NA
C_5F_8[a]	0.2	0.1	0.2	0.2	0.1	NA
C_4F_8O[a]	NA	0.1	NA	NA	0.1	0.4

Notes: NA denotes not applicable based on currently available information.

* Estimate includes multi-gas etch processes.

† Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing FC additive.

TABLE I–3 OF SUBPART I—DEFAULT EMISSION FACTORS FOR LCD MANUFACTURING

Process gases	Factors				
	Etch 1-Ui	CVD 1-Ui	Etch BCF_4	Etch $BCHF_3$	Etch BC_2F_6
CF_4	0.6	NA	NA	NA	NA
C_2F_6	NA	NA	NA	NA	NA
CHF_3	0.2	NA	0.07	NA	0.05
CH_2F_2	NA	NA	NA	NA	NA
C_3F_8	NA	NA	NA	NA	NA
c-C_4F_8	0.1	NA	0.009	0.02	NA
NF_3 Remote	NA	0.03	NA	NA	NA
NF_3	NA	0.3	NA	NA	NA
SF_6	0.3	0.9	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

TABLE I–4 OF SUBPART I—DEFAULT EMISSION FACTORS FOR PV MANUFACTURING

Process gases	Factors				
	Etch 1-Ui	CVD 1-Ui	Etch BCF_4	Etch BC_2F_6	CVD BCF_4
CF_4	0.7	NA	NA	NA	NA
C_2F_6	0.4	0.6	0.2	NA	0.2
CHF_3	0.4	NA	NA	NA	NA
CH_2F_2	NA	NA	NA	NA	NA
C_3F_8	NA	0.1	NA	NA	0.2
c-C_4F_8	0.2	0.1	0.1	0.1	0.1
NF_3 Remote	NA	NA	NA	NA	NA
NF_3	NA	0.3	NA	NA	NA
SF_6	0.4	0.4	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Subpart J—Ethanol Production

§ 98.100 Definition of the source category.

An ethanol production facility is a facility that produces ethanol from the fermentation of sugar, starch, grain, or cellulosic biomass feedstocks; or produces ethanol synthetically from ethylene or hydrogen and carbon monoxide.

§ 98.101 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an ethanol production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.102 GHGs to report.

You must report:

(a) Emissions of CO_2, N_2O, and CH_4 from on-site stationary combustion. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) Emissions of CH_4 from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(c) Emissions of CH_4 from on-site wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart II of this part.

§ 98.103 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart K—Ferroalloy Production

§ 98.110 Definition of the source category.

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

§ 98.111 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a ferroalloy production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.112 GHGs to report.

(a) You must report the CO_2 emissions from each electric arc furnace used for ferroalloy production.

(b) You must report the CH_4 emissions from each electric arc furnace used for the production of any ferroalloy listed in Table K–1 of this subpart.

(c) You must report the CO_2, CH_4, and N_2O emissions from each stationary combustion unit following the requirements specified in subpart C of this part.

§ 98.113 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO_2 process emissions consistent with the requirements in subpart C, you must determine using the procedure specified in paragraphs (b)(1) and (2) of this section the total CO_2 emissions from all electric arc furnaces that are used for ferroalloy production.

(1) For each EAF at your facility used for ferroalloy production, you must determine the mass of carbon in each carbon-containing input and output material for the electric arc furnace for each calendar month using Equation K–1 of this section. Carbon containing input materials include carbon eletrodes and carbonaceous reducing agents.

$$\begin{aligned}E_{CO2} = {} & \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{i} M_{\text{reducing agent}_i} \times C_{\text{reducing agent}_i}\right)_n \\ & + \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{m} M_{\text{electrode}_m} \times C_{\text{electrode}_m}\right)_n \\ & + \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{h} M_{\text{ore}_h} \times C_{\text{ore}_h}\right)_n \qquad \text{(Eq. K-1)} \\ & + \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{j} M_{\text{flux}_j} \times C_{\text{flux}_j}\right)_n \\ & - \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{k} M_{\text{product}_k} \times C_{\text{product}_k}\right)_n \\ & - \frac{44}{12}\times\sum_{n=1}^{12}\left(\sum_{l} M_{\text{non-product outgoing}_l} \times C_{\text{non-product outgoing}_l}\right)_n\end{aligned}$$

Where:

E_{CO_2} = Annual CO_2 mass emissions from an individual EAF, metric tons.

$M_{\text{reducing agent}_i}$ = Mass of reducing agent i fed, charged, or otherwise introduced into the EAF, metric tons.

$C_{\text{reducing agent}_i}$ = Carbon content in reducing agent i, metric tons of C/metric ton reducing agent.

$M_{\text{electrode}_m}$ = Mass of carbon electrode m consumed in the EAF, metric tons.

$C_{\text{electrode}_m}$ = Carbon content of the carbon electrode m, percent by weight, expressed as a decimal fraction.

M_{ore_h} = Mass of ore h charged to the EAF, metric tons.

C_{ore_h} = Carbon content in ore h, metric tons of C/metric ton ore.

M_{flux_j} = Mass of flux material j fed, charged, or otherwise introduced into the EAF to facilitate slag formation, metric tons.

C_{flux_j} = Carbon content in flux material j, metric tons of C/metric ton material.

M_{product_k} = Mass of alloy product k tapped from EAF, metric tons.

C_{product_k} = Carbon content in alloy product k, metric tons of C/metric ton product.

$M_{\text{non-product outgoing}_l}$ = Mass of non-product outgoing material l removed from EAF, metric tons.

$C_{\text{non-product outgoing}_l}$ = Carbon content in non-product outgoing material l, metric tons of C/metric ton.

(2) You must determine the total CO_2 emissions from the electric arc furnaces using Equation K–2 of this section:

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. K-2)}$$

Where:

CO_2 = Total annual CO_2 emissions, metric tons/year.

E_{CO2_k} = Annual CO_2 emissions calcaluated using Equation K–1 of this supart, metric tons/year.

k = Total number of EAFs at facility used for the ferroalloy production.

(c) For the electric arc furnaces used at your facility for the production of any ferroalloy listed in Table K–1 of this subpart, you must determine the total CH_4 emissions using the procedure specified in paragraphs (c)(1) and (2) of this section.

(1) For each EAF, calculate annual CH_4 emissions using Equation K–3 of this section:

$$E_{CH4} = \sum_{1}^{i}\left(M_{\text{product}_i} \times EF_{\text{product}_i}\right) \qquad \text{(Eq. K-3)}$$

Where:

E_{CH4} = Annual CH_4 emissions from an individual EAF, metric tons.

M_{product_i} = Annual mass of alloy product i produced in the EAF, metric tons.

EF_{product_i} = CH_4 emission factor for alloy product i from Table K–1 of this subpart, kg of CH_4 emissions per metric ton of alloy product i.

(2) You must determine the total CH_4 emissions using Equation K–4 of this section:

$$CH_4 = \sum_{1}^{j} E_{CH4_j} \qquad \text{(Eq. K-4)}$$

Where:

CH_4 = Total annual CH_4 emissions, metric tons/year.

E_{CH4_j} = Annual CH_4 emissions from EAF k calculated using Equation K–3 of this section, metric tons/year.

j = Total number of EAFs at facility used for the production of ferroalloys listed in Table K–1 of this subpart.

§ 98.114 Monitoring and QA/QC requirements.

If you determine CO_2 emissions using the carbon balance procedure in § 98.113(b), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing process input and output material by direct measurements or calculations using process operating information, and record the total mass of each material consumed or produced for each calendar month.

(b) For each process input and output material identified in paragraph (a) of this section, you must determine the average carbon content of the material for the specified period using information provided by your material supplier or by collecting and analyzing a representative sample of the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory at least annually using the test methods (and their QA/QC procedures) in § 98.7. Use ASTM E1941–04 (''Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys'') for analysis of metal ore and alloy product; ASTM D5373–02 (''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'') for analysis of carbonaceous reducing agents and carbon electrodes, and ASTM C25–06 (''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'') for analysis of flux materials such as limestone or dolomite.

§ 98.115 Procedures for estimating missing data.

For the carbon input procedure in § 98.113(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations.

(a) For each missing value of the carbon content the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing records of the mass of carbon-containing input or output material consumption, the substitute data value shall be the best available estimate of the mass of the input or output material. The owner or operator shall document and keep records of the procedures used for all such estimates.

(c) If you are required to calculate CH_4 emissions for the electric arc furnace as specified in § 98.113(c), then you are required to have 100 percent of the specified data for each reporting period.

§ 98.116 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (f) of this section.

(a) Annual CO_2 emissions from each electric arc furnace used for ferroalloy production, in metric tons and the method used to estimate these emissions.

(b) Annual CH_4 emissions from each electric arc furnace used for the production of any ferroalloy listed in Table K–1 of this subpart.

(c) Facility ferroalloy product production capacity (metric tons).

(d) Annual facility production quantity for each ferroalloy product (metric tons).

(d) Number of facility operating hours in calendar year.

(f) If you use the carbon balance procedure, report for each carbon-containing input and output material consumed or used (other than fuel), the information specified in paragraphs (g)(1) and (2) of this section.

(1) Annual material quantity (in metric tons).

(2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.117 Records that must be retained.

In addition to the records required by § 98.3(g) of this part, you must retain the records specified in paragraphs (a) through (e) of this section.

(a) Monthly facility production quantity for each ferroalloy product (in metric tons).

(b) Number of facility operating hours each month.

(c) If you use the carbon balance procedure, record for each carbon-containing input and output material consumed or used (other than fuel), the information specified in paragraphs (c)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(d) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input input and output to each electric arc furnace. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(e) If you are required to calculate CH_4 emissions for the electric arc furnace as specified in § 98.113(c), you must maintain records of the total amount of each alloy product produced for the specified reporting period, and the appropriate alloy-product specific emission factor used to calculate CH_4 emissions.

§ 98.118 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE K–1 OF SUBPART K—ELECTRIC ARC FURNACE (EAF) CH^4 EMISSION FACTORS

Alloy product produced in EAF	CH_4 Emission factor (kg CH_4 per metric ton product)		
	EAF operation		
	Batch-charging	Sprinkle-charging[a]	Sprinkle-charging and >750 °C[b]
silicon metal	1.5	1.2	0.7
ferrosilicon 90%	1.4	1.1	0.6
ferrosilicon 75%	1.3	1.0	0.5

TABLE K–1 OF SUBPART K—ELECTRIC ARC FURNACE (EAF) CH^4 EMISSION FACTORS—Continued

Alloy product produced in EAF	CH_4 Emission factor (kg CH_4 per metric ton product)		
	EAF operation		
	Batch-charging	Sprinkle-charging [a]	Sprinkle-charging and >750 °C [b]
ferrosilicon 65%	1.3	1.0	0.5

[a] Sprinkle-charging is charging intermittently every minute.

[b] Temperature measured in off-gas channel downstream of the furnace hood.

Subpart L—Fluorinated Greenhouse Gas Production

§ 98.120 Definition of the source category.

The fluorinated gas production source category consists of facilities that produce a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG or the generation of HFC–23 during the production of HCFC–22.

§ 98.121 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a fluorinated greenhouse gas production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.122 GHGs to report.

(a) You must report the CO_2, N_2O, and CH_4 emissions from each on-site stationary combustion unit. For these stationary combustion units, you must follow the applicable calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) You must report the total mass of each fluorinated GHG emitted from each fluorinated GHG production process and from all fluorinated GHG production processes at the facility.

§ 98.123 Calculating GHG emissions.

(a) The total mass of each fluorinated GHG product emitted annually from all fluorinated GHG production processes shall be estimated by using Equation L–1 of this section:

$$E_p = \sum_{p=1}^{n} \sum_{i=1}^{m} E_{Pip} \qquad \text{(Eq. L-1)}$$

Where:

E_P = Total mass of each fluorinated GHG product emitted annually from all production processes (metric tons).

E_{Pip} = Total mass of the fluorinated GHG product emitted from production process i over the period p (metric tons, defined in Equation L–3 of this section).

n = Number of concentration and flow measurement periods for the year.

m = Number of production processes.

(b) The total mass of fluorinated GHG by-product k emitted annually from all fluorinated GHG production processes shall be estimated by using Equation L–2 of this section:

$$E_{Bk} = \sum_{p=1}^{n} \sum_{i=1}^{m} E_{Bkip} \qquad \text{(Eq. L-2)}$$

Where:

E_{Bk} = Total mass of fluorinated GHG by-product k emitted annually from all production processes (metric tons).

E_{Bkip} = Total mass of fluorinated GHG by-product k emitted from production process i over the period p (metric tons, defined in Equation L–8 on this section).

n = Number of concentration and flow measurement periods for the year.

m = Number of production processes.

(c) The total mass of each fluorinated GHG product emitted from production process i over the period p shall be estimated at least daily by calculating the difference between the expected production of the fluorinated GHG based on the consumption of reactants (e.g., HF and a chlorocarbon reactant) and the measured production of the fluorinated GHG, accounting for yield losses related to by-products and wastes. This calculation shall be performed for each reactant, using Equation L–3 of this section. Estimated emissions shall equal the average of the results obtained for each reactant.

$$E_{Pip} = \frac{R * MW_P * SC_P}{MW_R * SC_R} - P - \sum_{j=1}^{q} \left(C_p * W_{Dj} \right) - \sum_{k=1}^{u} L_{Bkip} \qquad \text{(Eq. L-3)}$$

Where:

E_{Pip} = Total mass of each fluorinated GHG product emitted from production process i over the period p (metric tons).

P = Total mass of the fluorinated GHG produced by production process i over the period p (metric tons).

R = Total mass of the reactant that is consumed by production process i over the period p (metric tons, defined in Equation L–4).

MW_R = Molecular weight of the reactant.

MW_P = Molecular weight of the fluorinated GHG produced.

SC_R = Stoichiometric coefficient of the reactant.

SC_P = Stoichiometric coefficient of the fluorinated GHG produced.

C_P = Concentration (mass fraction) of the fluorinated GHG product in stream j of destroyed wastes. If this concentration is only a trace concentration, C_P is equal to zero.

W_{Dj} = Mass of wastes removed from production process i in stream j and destroyed over the period p (metric tons, defined in Equation L–5 of this section).

L_{Bkip} = Yield loss related to by-product k for production process i over the period p (metric tons, defined in Equation L–6 of this section).

q = Number of waste streams destroyed in production process i.

u = Number of by-products generated in production process i.

(d) The total mass of the reactant that is consumed by production process i over the period p shall be estimated by using Equation L–4 of this section:

$$R = R_F - R_R \qquad \text{(Eq. L-4)}$$

Where:

R = Total mass of the reactant that is consumed by production process i over the period p (metric tons).

R_F = Total mass of the reactant that is fed into production process i over the period p (metric tons).

R_R = Total mass of the reactant that is permanently removed from production process i over the period p (metric tons).

(e) The mass of wastes removed from production process i in stream j and destroyed over the period p shall be estimated using Equation L–5 of this section:

$$W_{Dj} = W_{Fj} \; * \; DE \qquad \text{(Eq. L-5)}$$

Where:

W_{Dj} = The mass of wastes removed from production process i in stream j and destroyed over the period p (metric tons).

W_{Fj} = The total mass of wastes removed from production process i in stream j and fed into the destruction device over the period p (metric tons).

DE = Destruction Efficiency of the destruction device (fraction).

(f) Yield loss related to by-product k for production process i over period p shall be estimated using Equation L–6 of this section:

$$L_{Bkip} = \frac{\left(B_{kip} \; * MW_P \; * ME_{Bk}\right)}{\left(MW_{Bk} * ME_p\right)} \qquad \text{(Eq. L-6)}$$

Where:

L_{Bkip} = Yield loss related to by-product k for production process i over the period p (metric tons).

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons, defined in Equation L–7 of this section).

MW_P = Molecular weight of the fluorinated GHG produced.

MW_{Bk} = Molecular weight of by-product k.

ME_{Bk} = Moles of the element shared by the reactant, product, and by-product k per mole of by-product k.

ME_P = Moles of the element shared by the reactant, product, and by-product k per mole of the product.

(g) If by-product k is responsible for yield loss in production process i and occurs in any process stream in more than trace concentrations, the mass of by-product k generated by production process i over the period p shall be estimated using Equation L–7 of this section:

$$B_{kip} \; = \sum_{j}^{q} c_{Bjk} * S_{j} \qquad \text{(Eq. L-7)}$$

Where:

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons).

C_{Bkj} = Concentration (mass fraction) of the by-product k in stream j of production process i over the period p. If this concentration is only a trace concentration, C_{Bkj} is equal to zero.

S_j = Mass flow of process stream j of production process i over the period p.

q = Number of streams in production process i.

(h) If by-product k is responsible for yield loss, is a fluorinated GHG, occurs in any process stream in more than trace concentrations, and is not completely recaptured or completely destroyed; the total mass of by-product k emitted from production process i over the period p shall be estimated at least daily using Equation L–8 of this section:

$$E_{Bkip} = B_{kip} - \sum_{j=1}^{q} c_{Bkj} * \; W_{Dj} - \sum_{l=1}^{v} c_{Bkl} * S_{Rl} \qquad \text{(Eq. L-8)}$$

Where:

E_{Bkip} = Mass of by-product k emitted from production process i over the period p (metric tons).

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons).

C_{Bkj} = Concentration (mass fraction) of the by-product k in stream j of destroyed wastes over the period p. If this concentration is only a trace concentration, C_{Bj} is equal to zero.

W_{Dj} = The mass of wastes that are removed from production process i in stream j and that are destroyed over the period p (metric tons, defined in Equation L–5 of this section).

C_{Bkl} = The concentration (mass fraction) of the by-product k in stream l of recaptured material over the period p. If this concentration is only a trace concentration, C_{Bkl} is equal to zero.

S_{Rl} = The mass of materials that are removed from production process i in stream l and that are recaptured over the period p.

q = Number of waste streams destroyed in production process i.

v = Number of streams recaptured in production process i.

§ 98.124 Monitoring and QA/QC requirements.

(a) The total mass of fluorinated GHGs produced over the period p shall be estimated at least daily using the methods and measurements set forth in §§ 98.413(b) and 98.414.

(b) The total mass of each reactant fed into the production process shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(c) The total mass of each reactant permanently removed from the production process shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the reactant, the concentration of the reactant shall be measured at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the reactant permanently removed from the production process.

(d) If the waste permanently removed from the production process and fed into the destruction device contains more than trace concentrations of the fluorinated GHG product, the mass of waste fed into the destruction device shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the product, the concentration of the product shall be measured at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(e) If a by-product is responsible for yield loss and occurs in any process stream in more than trace concentrations, the mass flow of each process stream that contains more than trace concentrations of the by-product shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the by-product, the concentration of the by-product shall be measured at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(f) If a by-product is a fluorinated GHG, occurs in more than trace concentrations in any process stream, occurs in more than trace concentrations in any stream that is recaptured or is fed into a destruction device, and is not completely recaptured or completely destroyed; the mass flow of each stream that contains more than trace concentrations of the by-product and that is recaptured or is fed into the destruction device or shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the by-product, the concentration of the by-product shall be measured at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(g) All flowmeters, scales, load cells, and volumetric and density measures used to measure quantities that are to be reported under § 98.126 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(h) All gas chromatographs used to determine the concentration of fluorinated greenhouse gases in process streams shall be calibrated at least monthly through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

(i) For purposes of equation L–5, the destruction efficiency can initially be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device. Fluorinated GHG production facilities that destroy fluorinated GHGs shall conduct annual measurements of mass flow and fluorinated GHG concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of fluorinated GHGs being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.123, or

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.123.

(j) In their estimates of the mass of fluorinated GHGs destroyed, fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(k) Fluorinated GHG production facilities shall account for fluorinated GHG emissions that occur as a result of startups, shutdowns, and malfunctions, either recording fluorinated GHG emissions during these events, or documenting that these events do not result in significant fluorinated GHG emissions.

§ 98.125 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the mass of fluorinated GHG produced, the mass of reactants fed into the production process, the mass of reactants permanently removed from the production process, the mass flow of process streams containing more than trace concentrations of by-products that lead to yield losses, or the mass of wastes fed into the destruction device; the substitute value of that parameter shall be a secondary mass measurement taken during the period the primary mass measurement was not available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable; then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product.

(2) For each missing value of fluorinated GHG concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(3) If the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing, you shall develop a best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in (a)(1) and (2) would lead to a significant under- or overestimate of the parameter.

§ 98.126 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), you shall report the following information for each production process at the facility.

(1) The total mass of the fluorinated GHG produced in metric tons, by chemical.

(2) The total mass of each reactant fed into the production process in metric tons, by chemical.

(3) The total mass of each reactant permanently removed from the production process in metric tons, by chemical.

(4) The total mass of the fluorinated GHG product removed from the production process and destroyed.

(5) The mass of each by-product generated.

(6) The mass of each by-product destroyed at the facility.

(7) The mass of each by-product recaptured and sent off-site for destruction.

(8) The mass of each by-product recaptured for other purposes.

(9) The mass of each fluorinated GHG emitted.

(b) Where missing data have been estimated pursuant to § 98.125, you shall report the information specified in paragraphs (b)(1) and (2) of this section.

(1) The reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(2) Where the missing data have been estimated pursuant to § 98.125(a)(3), you shall also report the rationale for the methods used to estimate the missing data and why the methods specified in § 98.125 (a)(1) and (2) would lead to a significant under- or overestimate of the parameter(s).

(c) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate calculated from paragraphs(c)(2) and (c)(3) of this section in kg/hr.

(d) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Test methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

§ 98.127 Records that must be retained.

(a) In addition to the data required by §§ 98.123 and 98.126, you shall retain the following records:

(1) Dated records of the data used to estimate the data reported under §§ 98.123 and 98.126.

(2) Dated records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to § 98.124(g) and (h).

(b) In addition to the data required by paragraph (a) of this section, the designated representative of a fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report and annaul destruction device outlet reports in § 98.126(c) and (d).

§ 98.128 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart M—Food Processing

§ 98.130 Definition of the source category.

Food processing facilities prepare raw ingredients for consumption by animals or humans. Food processing facilities transform raw ingredients into food, transform food into other forms for consumption by humans or animals, or transform food for further processing by the food processing industry.

§ 98.131 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a food processing operation and the facility meets the requirements of either *§ 98.2*(a)(1) or (2).

§ 98.132 GHGs to report.

You must report:

(a) Emissions of CO_2, N_2O, and CH_4 from on-site stationary combustion. You must follow the requirements of subpart C of this part.

(b) Emissions of CH_4 from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(c) Emissions of CH_4 from on-site wastewater treatment. You must follow the requirements of subpart II of this part.

§ 98.133 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart N—Glass Production

§ 98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous glass melting furnaces to produce glass.

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ 98.141 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.142 GHGs to report.

(a) You must report CO_2 process emissions from each continuous glass melting furnace at your glass manufacturing facility as required by this subpart.

(b) You must report the CO_2, N_2O, and CH^4 emissions from fuel combustion at each continuous glass melting furnace and at any other on-site stationary fuel combustion unit. For each stationary fuel combustion unit, you must follow the requirements of subpart C of this part.

§ 98.143 Calculating GHG emissions.

(a) If you operate and maintain a continuous emission monitoring system (CEMS) that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you shall calculate process emissions of CO_2 from each glass melting furnace according to paragraphs (b)(1) through (5) of this section, except as specified in paragraph (c) of this section.

(1) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(2) Determine the quantity of each carbonate-based raw material charged to the furnace.

(3) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N–1 to this subpart.

(4) Use Equation N–1 of this subpart to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} MF_i \bullet M_i \bullet EF_i \bullet F_i \qquad \text{(Eq. N-1)}$$

Where:

E_{CO2} = Process mass emissions of CO_2 (metric ton/yr) from the furnace.

n = Number of carbonate-based raw materials charged to furnace.

MF_i = Mass fraction of carbonate-based mineral i in carbonate-based raw material i (dimensionless unit).

M_i = Mass of carbonate-based raw material i charged to furnace (metric ton/yr).

EF_i = Emission factor for carbonate-based raw material i (metric ton CO_2/metric ton carbonate-based raw material).

F_i = Fraction of calcination achieved for carbonate-based raw material i, assumed to be equal to 1.0 (dimensionless unit).

(5) You must determine the total process CO_2 emissions from continuous glass melting furnaces at the facility using Equation N–2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. N-2)}$$

Where:

CO_2 = Total annual process CO_2 emissions from glass manufacturing facility (metric tons/year).

ECO_{2i} = Annual CO_2 emissions from glass melting furnace i (metric tons CO_2/year).

k = Number of continuous glass melting furnaces.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N–1 of this section.

§ 98.144 Monitoring and QA/QC requirements.

(a) You shall determine annual amounts of carbonate-based raw materials charged to each continuous glass melting furnace using calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) If raw material supplier data are used to determine carbonate-based mineral mass fractions according to § 98.143(b)(1), measurements of the mass fraction of each carbonate-based mineral in the carbonate-based raw materials shall be made at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using a suitable method published by a consensus standards organization (*e.g.*, ASTM Method D3682, Test Method for Major and Minor Elements in Coal and Coke Ash by Atomic Absorption Method).

§ 98.145 Procedures for estimating missing data.

(a) Missing data on the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace shall be replaced by the average of the data from the previous month and the following month for each carbonate-based raw material charged.

(b) Missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials shall be replaced using the assumption that the mass fraction of each carbonate based mineral is 1.0.

§ 98.146 Data reporting requirements.

You shall report the information specified in paragraphs (a) through (d) of this section for each continuous glass melting furnace.

(a) Annual process emissions of CO_2, in metric tons/yr.

(b) Annual quantity of each carbonate-based raw material charged, in metric tons/yr.

(c) Annual quantity of glass produced, in metric tons/yr.

(d) If process CO_2 emissions are calculated based on data provided by the raw material supplier according to § 98.143(a)(1), the carbonate-based mineral mass fraction (as percent) for each carbonate-based raw material charged to a continuous glass melting furnace.

§ 98.147 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records listed in paragraphs (a) through (e) of this section.

(a) Total number of continuous glass melting furnaces.

(b) Monthly glass production rate for each continuous glass melting furnace.

(c) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace.

(d) If process CO_2 emissions are calculated using data provided by the raw material supplier according to § 98.143(b)(1), you must retain the records in paragraphs (d)(1) and (2) of this section.

(1) Data on carbonate-based mineral mass fractions provided by the raw material supplier.

(2) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace.

(e) All other documentation used to support the reported GHG emissions.

§ 98.148 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE N–1 OF SUBPART N—CO_2 EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS

Carbonate-based raw material—mineral	CO_2 Emission factor[a]
Limestone—$CaCO_3$	0.440

TABLE N–1 OF SUBPART N—CO_2 EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS—Continued

Carbonate-based raw material—mineral	CO_2 Emission factor [a]
Dolomite—$CaMg(CO_3)_2$	0.477
Sodium carbonate/soda ash—Na_2CO_3	0.415

[a] Emission factors in units of metric tons of CO_2 emitted per metric ton of carbonate-based raw material charged to the furnace.

Subpart O—HCFC–22 Production and HFC–23 Destruction

§ 98.150 Definition of the source category.

The HCFC–22 production and HFC–23 destruction source category consists of HCFC–22 production processes and HFC–23 destruction processes.

(a) An HCFC–22 production process produces HCFC–22 (chlorodifluoromethane, or $CHClF_2$) from chloroform ($CHCl_3$) and hydrogen fluoride (HF).

(b) An HFC–23 destruction process is any process in which HFC–23 undergoes destruction. An HFC–23 destruction process may or may not be co-located with an HCFC–22 production process at the same facility.

§ 98.151 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a HCFC–22 production or HFC–23 destruction process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.152 GHGs to report.

(a) You must report the CO_2, N_2O, and CH_4 emissions from each on-site stationary combustion unit. For these stationary combustion units, you must follow the applicable calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) You must report HFC–23 emissions from HCFC–22 production processes and HFC–23 destruction processes.

§ 98.153 Calculating GHG emissions.

(a) The total mass of HFC–23 generated from each HCFC–22 production process shall be estimated by using one of two methods, as applicable:

(1) Where the mass flow of the combined stream of HFC–23 and another reaction product (*e.g.*, HCl) is measured, multiply the daily (or more frequent) HFC–23 concentration measurement (which may be the average of more frequent concentration measurements) by the daily (or more frequent) mass flow of the combined stream of HFC–23 and the other product. To estimate annual HFC–23 production, sum the daily (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–1 of this section:

$$G_{23} = \sum_{p=1}^{n} c_{23} * F_p * 10^{-3} \qquad \text{(Eq. O-1)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).
c_{23} = Fraction HFC–23 by weight in HFC–23/other product stream.
F_p = Mass flow of HFC–23/other product stream during the period p (kg).
p = Period over which mass flows and concentrations are measured.
n = Number of concentration and flow measurement periods for the year.
10^{-3} = Conversion factor from kilograms to metric tons.

(2) Where the mass of only a reaction product other than HFC–23 (either HCFC–22 or HCl) is measured, multiply the ratio of the daily (or more frequent) measurement of the HFC–23 concentration and the daily (or more frequent) measurement of the other product concentration by the daily (or more frequent) mass produced of the other product. To estimate annual HFC–23 production, sum the daily (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–2 of this section, assuming that the other product is HCFC–22. If the other product is HCl, HCl may be substituted for HCFC–22 in Equations O–2 and O–3 of this section.

$$G_{23} = \sum_{p=1}^{n} \left(\frac{c_{23}}{c_{22}} \right) * P_{22} * 10^{-3} \qquad \text{(Eq. O-2)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).
c_{23} = Fraction HFC–23 by weight in HCFC–22/HFC–23 stream.
c_{22} = Fraction HCFC–22 by weight in HCFC–22/HFC–23 stream.
P_{22} = Mass of HCFC–22 produced over the period p (kg).
p = Period over which masses and concentrations are measured.
n = Number of concentration and mass measurement periods for the year.
10^{-3} = Conversion factor from kilograms to metric tons.

(b) The mass of HCFC–22 produced over the period p shall be estimated by using Equation O–3 of this section:

$$P_{22} = LF * \left(O_{22} - U_{22} \right) \qquad \text{(Eq. O-3)}$$

Where:

P_{22} = Mass of HCFC–22 produced over the period p (kg).
O_{22} = mass of HCFC–22 that is measured coming out of the Production process over the period p (kg).
U_{22} = Mass of used HCFC–22 that is added to the production process upstream of the output measurement over the period p (kg).
LF = Factor to account for the loss of HCFC–22 upstream of the measurement. The value for LF shall be determined pursuant to § 98.154(e).

(c) For HCFC–22 production facilities that do not use a thermal oxidizer or have a thermal oxidizer that is not directly connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–4 of this section:

$$E_{23} = G_{23} - \left(S_{23} + OD_{23} + D_{23} \right) \qquad \text{(Eq. O-4)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).
G_{23} = Mass of HFC–23 generated annually (metric tons).
S_{23} = Mass of HFC–23 packaged for sale annually (metric tons).
OD_{23} = Mass of HFC–23 sent off-site for destruction (metric tons).
D_{23} = Mass of HFC–23 destroyed on-site (metric tons).

(d) For HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–5 of this section:

$$E_{23} = E_L + E_{PV} + E_D \qquad \text{(Eq. O-5)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).

E_L = Mass of HFC–23 emitted annually from equipment leaks, calculated using Equation O–6 (metric tons).

E_{PV} = Mass of HFC–23 emitted annually from process vents, calculated using Equation O–7 (metric tons).

E_D = Mass of HFC–23 emitted annually from thermal oxidizer (metric tons), calculated using Equation O–9 of this section.

(e) The mass of HFC–23 emitted annually from equipment leaks (for use in Equation O–5 of this section) shall be estimated by using Equation O–6 of this section:

$$E_L = \sum_{p=1}^{n} \sum_{t} c_{23} * \left(F_{Gt} * N_{Gt} + F_{Lt} * N_{Lt} \right) * 10^{-3} \qquad \text{(Eq. O-6)}$$

Where:

E_L = Mass of HFC–23 emitted annually from equipment leaks (metric tons).

c_{23} = Fraction HFC–23 by weight in the stream(s) in the equipment.

F_{Gt} = The applicable leak rate specified in table O–1 for each source of equipment type and service t with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).

N_{Gt} = The number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv as determined according to § 98.154(h).

F_{Lt} = The applicable leak rate specified in table O–1 for each source of equipment type and service t with a screening value of less than 10,000 ppmv (kg/hr/source).

N_{Lt} = The number of sources of equipment type and service t with screening values less than 10,000 ppmv as determined according to § 98.154(i).

p = One hour.

n = Number of hours during the year during which equipment contained HFC–23.

t = Equipment type and service as specified in Table O–1.

10^{-3} = Factor converting kg to metric tons.

TABLE O–1 OF SUBPART O—EMISSION FACTORS FOR EQUIPMENT LEAKS

Equipment type	Service	Emission factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

(f) The mass of HFC–23 emitted annually from process vents (for use in Equation O–5 of this section) shall be estimated by using Equation O–7 of this section:

$$E_{PV} = \sum_{p=1}^{n} ER_T * \left(\frac{PR_p}{PR_T} \right) * l_p * 10^{-3} \qquad \text{(Eq. O-7)}$$

Where:

E_{PV} = Mass of HFC–23 emitted annually from process vents (metric tons).

ER_T = The HFC–23 emission rate from the process vents during the period of the most recent test (kg/hr).

PR_p = The HCFC–22 production rate during the period p (kg/hr).

PR_T = The HCFC–22 production rate during the most recent test period (kg/hr).

l_p = The length of the period p (hours).

10^{-3}= Factor converting kg to metric tons.

n = The number of periods in a year.

(g) For facilities that destroy HFC–23, the total mass of HFC–23 destroyed shall be estimated by using Equation O–8 of this section:

$$D = F_D * DE \qquad \text{(Eq. O-8)}$$

Where:

D = Mass of HFC–23 destroyed annually (metric tons).

F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).

DE = Destruction Efficiency of the destruction device (fraction).

(h) The total mass of HFC–23 emitted from destruction devices shall be estimated by using Equation O–9 of this section:

$$E_D = F_D - D \qquad \text{(Eq. O-9)}$$

Where:

E_D = Mass of HFC–23 emitted annually from the destruction device (metric tons).

F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).

D = Mass of HFC–23 destroyed annually (metric tons).

§ 98.154 Monitoring and QA/QC requirements.

These requirements apply to measurements that are reported under this subpart or that are used to estimate reported quantities pursuant to § 98.153.

(a) The concentrations (fractions by weight) of HFC–23 and HCFC–22 in the product stream shall be measured at least daily using equipment and methods (*e.g.*, gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC–23 shall be measured continuously using a flow meter with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC–22 or HCl coming out of the production process shall be measured at least daily using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC–22 added back into the production process upstream of the output measurement in paragraph (c) of this section shall be measured at least daily (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(e) The loss factor LF in Equation O–3 of this subpart for the mass of HCFC–22 produced shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the Administrator, to account for losses of HCFC–22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC–23 packaged for sale shall be measured at least daily (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC–23 sent off-site for destruction shall be measured at least daily (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentration of the fluorinated GHG shall be measured at least daily using equipment and methods (*e.g.*, gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 sent to another facility for destruction.

(h) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv shall be determined using EPA Method 21 at 40 CFR part 60, appendix A–7, and defining a leak as follows:

(1) A leak source that could emit HFC–23, and

(2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(i) The number of sources of equipment type t with screening values less than 10,000 ppmv shall be the difference between the number of leak sources of equipment type t that could emit HFC–23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (h) of this section.

(j) The mass of HFC–23 emitted from process vents shall be estimated at least monthly by conducting emissions tests at process vents at least annually and by incorporating the results of the most recent emissions test into Equation O–6 of this subpart. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC–23 if sustained over one year.

(k) For purposes of Equation O–8, the destruction efficiency can initially be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device. HFC–23 destruction facilities shall conduct annual measurements of mass flow and HFC–23 concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of HFC–23 being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.153.

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.153.

(l) Designated representatives of HCFC–22 production facilities shall account for HFC–23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC–23 generation and emissions during these events, or documenting that these events do not result in significant HFC–23 generation and/or emissions.

(m) The mass of HFC–23 fed into the destruction device shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentrations of the HFC–23 shall be measured at least daily using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 destroyed.

(n) In their estimates of the mass of HFC–23 destroyed, designated representatives of HFC–23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(o) All flowmeters, scales, and load cells used to measure quantities that are to be reported under § 98.156 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(p) All gas chromatographs used to determine the concentration of HFC–23 in process streams shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR part 51, appendix M) with known HFC–23 concentrations that are in the same range (fractions by mass) as the process samples.

§ 98.155 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the HFC–23 or HCFC–22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses.

(3) Notwithstanding paragraphs (a)(1) and (2) of this section, if the owner or operator has reason to believe that the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing (e.g., because the monitoring failure was linked to a process disturbance that is likely to have significantly increased the HFC–23 generation rate), the designated representative of the HCFC–22 production facility shall develop his or her best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in (a)(1) and (2) would probably lead to a significant under- or overestimate of the parameter.

§ 98.156 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the designated representative of an HCFC–22 production facility shall report the following information at the facility level:

(1) The mass of HCFC–22 produced in metric tons.

(2) The mass of reactants fed into the process in metric tons of reactant.

(3) The mass (in metric tons) of materials other than HCFC–22 and HFC–23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.

(4) The method for tracking startups, shutdowns, and malfunctions and HFC–23 generation/emissions during these events.

(5) The names and addresses of facilities to which any HFC–23 was sent for destruction, and the quantities of HFC–23 (metric tons) sent to each.

(6) The total mass of the HFC–23 generated in metric tons.

(7) The mass of any HFC–23 packaged for sale in metric tons.

(8) The mass of any HFC–23 sent off site for destruction in metric tons.

(9) The mass of HFC–23 emitted in metric tons.

(10) The mass of HFC–23 emitted from equipment leaks in metric tons.

(11) The mass of HFC–23 emitted from process vents in metric tons.

(b) Where missing data have been estimated pursuant to § 98.155, the designated representative of the HCFC–22 production facility or HCF–23 destruction facility shall report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(1) Where the missing data have been estimated pursuant to § 98.155(a)(3), the designated representative shall also report the rationale for the methods used to estimate the missing data and why the methods specified in § 98.155(a)(1) and (2) would probably lead to a significant under- or overestimate of the parameter(s).

(c) In addition to the information required by § 98.3(c), the designated representative of a facility that destroys HFC–23 shall report the following for each HFC–23 destruction process:

(1) The mass of HFC–23 fed into the thermal oxidizer.

(2) The mass of HFC–23 destroyed.

(3) The mass of HFC–23 emitted from the thermal oxidizer.

(d) The designated representative of each HFC–23 destruction facility shall report the results of the facility's annual HFC–23 concentration measurements at the outlet of the destruction device, including:

(1) The flow rate of HFC–23 being fed into the destruction device in kg/hr.

(2) The concentration (mass fraction) of HFC–23 at the outlet of the destruction device.

(3) The flow rate at the outlet of the destruction device in kg/hr.

(4) The emission rate calculated from paragraphs (c)(2) and (3) of this section in kg/hr.

(e) The designated representative of an HFC–23 destruction facility shall submit a one-time report including the following information:

(1) The destruction unit's destruction efficiency (DE).

(2) The methods used to determine the unit's destruction efficiency.

(3) The methods used to record the mass of HFC–23 destroyed.

(4) The name of other relevant federal or state regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC–23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

§ 98.157 Records that must be retained.

(a) In addition to the data required by § 98.3(g), the designated representative of an HCFC–22 production facility shall retain the following records:

(1) The data used to estimate HFC–23 emissions.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this rule, including the industry standards or manufacturer directions used for calibration pursuant to § 98.154(o) and (p).

(b) In addition to the data required by § 98.3(g), the designated representative of a HFC–23 destruction facility shall retain the following records:

(1) Records documenting their one-time and annual reports in § 98.156(c), (d), and (e).

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to § 98.154(o) and (p).

§ 98.158 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart P—Hydrogen Production

§ 98.160 Definition of the source category.

(a) A hydrogen production source category produces hydrogen gas that is consumed at sites other than where it is produced.

(b) This source category comprises process units that produce hydrogen by oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes hydrogen production facilities located within a petroleum refinery and that are not owned or under the direct control of the refinery owner and operator.

§ 98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.162 GHGs to report.

You must report:

(a) CO_2 process emissions for each hydrogen production process unit.

(b) CO_2, CH_4, and N_2O emissions from the combustion of fuels in each hydrogen production unit and any other stationary combustion units by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(c) For CO_2 collected and used on site or transferred off site, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart PP of this part.

§ 98.163 Calculating GHG emissions.

You must determine CO_2 emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) *Continuous emission monitoring system.* Any hydrogen process unit that meets the conditions specified in § 98.33(b)(5)(iii)(A), (B), and (C), or § 98.33(b)(5)(ii)(A) through (F) shall calculate total CO_2 emissions using a continuous emissions monitoring system according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) *Feedstock material balance approach.* If you do not measure total emissions with a CEMS, you must calculate the annual CO_2 process emissions from feedstock used for hydrogen production.

(1) *Gaseous feedstock.* You must calculate the total CO_2 process emissions from gaseous feedstock according to Equation P–1 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n * \frac{MW}{MVC} \right) * 0.001 \qquad \text{(Eq. P-1)}$$

Where:

CO_2 = Annual CO_2 process emissions arising from feedstock consumption (metric tons).

$(Fdstk)_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

$(CC)_n$ = Average carbon content of the gaseous feedstock, from the analysis results for month n (kg C per kg of feedstock).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

k = Months per year.

44/12 = Ratio of molecular weights, CO_2 to carbon. and

0.001 = Conversion factor from kg to metric tons.

(2) *Liquid feedstock.* You must calculate the total CO_2 process emissions from liquid feedstock according to Equation P–2 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n \right) * 0.001 \qquad \text{(Eq. P-2)}$$

Where:

CO_2 = Annual CO_2 emissions arising from feedstock consumption (metric tons).

$(Fdstk)_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

$(CC)_n$ = Average carbon content of the liquid feedstock, from the analysis results for month n (kg C per gallon of feedstock).

k = Months per year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(3) *Solid feedstock.* You must calculate the total CO_2 process emissions from solid feedstock according to Equation P–3 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n \right) * 0.001 \qquad \text{(Eq. P-3)}$$

Where:

CO_2 = Annual CO_2 emissions from feedstock consumption in metric tons per month (metric tons).

$(Fdstk)_n$ = Mass of solid feedstock used in month n (kg of feedstock).

$(CC)_n$ = Average carbon content of the solid feedstock, from the analysis results for month n (kg C per kg of feedstock).

k = Months per year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

§ 98.164 Monitoring and QA/QC requirements.

(a) Facilities that use CEMS must comply with the monitoring and QA/QC procedures specified in § 98.34(e).

(b) The quantity of gaseous or liquid feedstock consumed must be measured continuously using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(c) You must collect a sample of each feedstock and analyze the carbon content of each sample using appropriate test methods incorporated by reference in § 98.7. The minimum frequency of the fuel sampling and analysis is monthly.

(d) All fuel flow meters, gas composition monitors, and heating value monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(e) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

§ 98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure.

(b) There are no missing data procedures for carbon content. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

(c) For missing CEMS data, you must use the missing data procedures in § 98.35.

§ 98.166 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each process unit:

(a) Facilities that use CEMS must comply with the procedures specified in § 98.36(a)(1)(iv).

(b) Annual total consumption of feedstock for hydrogen production; annual total of hydrogen produced; and annual total of ammonia produced, if applicable.

(c) Monthly analyses of carbon content for each feedstock used in hydrogen production (kg carbon/kg of feedstock).

§ 98.167 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) For all CEMS, you must comply with the CEMS recordkeeping requirements in § 98.37.

(b) Monthly analyses of carbon content for each feedstock used in hydrogen production.

§ 98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Q—Iron and Steel Production

§ 98.170 Definition of the source category.

The iron and steel production source category includes facilities with any of the following processes: Taconite iron ore processing, integrated iron and steel manufacturing, cokemaking not colocated with an integrated iron and steel manufacturing process, and electric arc furnace (EAF) steelmaking not colocated 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.

§ 98.171 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an iron and steel production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.172 GHGs to report.

(a) You must report combustion-related CO_2, CH_4, and N_2O emissions from each stationary combustion unit and follow the requirements in subpart C of this part. Stationary combustion units include, but are not limited to, by-product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flares, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report process-related CO_2 emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace by following the procedures in this subpart.

(c) You must report CO_2 emissions from each coke pushing process by following the procedures in this subpart.

§ 98.173 Calculating GHG emissions.

(a) For each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace, you must determine CO_2 emissions using the procedures in paragraph (a)(1), (a)(2), or (3) of this section as appropriate.

(1) Continuous emissions monitoring system (CEMS). If you operate and maintain a CEMS that measures CO_2 emissions consistent with the requirements in subpart C, you must estimate total CO_2 emissions according to the requirements in § 98.33.

(2) *Carbon mass balance method.* For the carbon balance method, calculate the mass emissions rate of CO_2 in each calendar month for each process as specified in paragraphs (a)(2)(i) through (vii) of this section. The calculations are based on the monthly mass of inputs and outputs to each process and the respective weight fraction of carbon. If you have a process input or output that contains carbon that is not included in the Equations, you must account for the carbon and mass rate of that process input or output in your calculations.

(i) For taconite indurating furnaces, estimate CO_2 emissions using Equation Q–1 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star \left[(F_s)_n \star (C_{sf})_n + (F_g)_n \star (C_{gf})_n \star \frac{MW}{MVC} \star 0.001 + (F_1)_n \star (C_{1f})_n \star 0.001 + (O)_n \star (C_o) - (P)_n \star (C_p)_n \right] \qquad \text{(Eq. Q-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the indurating furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(F_s)_n$ = Mass of the solid fuel combusted in month ''n'' (metric tons).

$(C_{sf})_n$ = Carbon content of the solid fuel, from the fuel analysis results for month ''n'' (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

$(F_g)_n$ = Volume of the gaseous fuel combusted in month ''n'' (scf).

$(C_{gf})_n$ = Average carbon content of the gaseous fuel, from the fuel analysis results for month ''n'' (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

$(F_l)_n$ = Volume of the liquid fuel combusted in month ''n'' (gallons).

$(C_{lf})_n$ = Carbon content of the liquid fuel, from the fuel analysis results for month ''n'' (kg C per gallon of fuel).

$(O)_n$ = Mass of greenball (taconite) pellets fed to the furnace in month ''n'' (metric tons).

$(C_0)_n$ = Carbon content of the greenball (taconite) pellets, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(P)_n$ = Mass of fired pellets produced by the furnace in month ''n'' (metric tons).

$(C_p)_n$ = Carbon content of the fired pellets, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate CO_2 emissions using Equation Q–2 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star \Big[(Iron)_n \star (C_{Iron})_n + (Scrap)_n \star (C_{Scrap})_n + (Flux)_n \star (C_{Flux})_n + (Carbon)_n \star (C_{Carbon})_n - (Steel)_n \star (C_{Steel})_n - (Slag)_n \star (C_{Slag})_n \Big] \qquad \text{(Eq. Q-2)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the basic oxygen furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Iron)_n$ = Mass of molten iron charged to the furnace in month ''n'' (metric tons).

$(C_{Iron})_n$ = Carbon content of the molten iron, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Scrap)_n$ = Mass of ferrous scrap charged to the furnace in month ''n'' (metric tons).

$(C_{Scrap})_n$ = Average carbon content of the ferrous scrap, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Flux)_n$ = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month ''n'' (metric tons).

$(C_{Flux})_n$ = Average carbon content of the flux materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Carbon)_n$ = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month ''n'' (metric tons).

$(C_{Carbon})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Steel)_n$ = Mass of molten steel produced by the furnace in month ''n'' (metric tons).

$(C_{Steel})_n$ = Average carbon content of the steel, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Slag)_n$ = Mass of slag produced by the furnace in month ''n'' (metric tons).

$(C_{Slag})_n$ = Average carbon content of the slag, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(iii) For non-recovery coke oven batteries, estimate CO_2 emissions using Equation Q–3 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star \Big[(Coal)_n \star (C_{Coal})_n - (Coke)_n \star (C_{Coke})_n \Big] \qquad \text{(Eq. Q-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the non-recovery coke oven battery (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Coal)_n$ = Mass of coal charged to the battery in month ''n'' (metric tons).

$(C_{Coal})_n$ = Carbon content of the coal, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Coke)_n$ = Mass of coke produced by the battery in month ''n'' (metric tons).

$(C_{Coke})_n$ = Carbon content of the coke, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(iv) For sinter processes, estimate CO_2 emissions using Equation Q–4 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star \Big[(F_g)_n \star (C_{gf})_n \star \frac{MW}{MVC} \star 0.001 + (Feed)_n \star (C_{Feed}) - (Sinter)_n \star (C_{Sinter})_n \Big] \qquad \text{(Eq. Q-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the sinter process (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(F_g)_n$ = Volume of the gaseous fuel combusted in month ''n'' (scf).

$(C_{gf})_n$ = Average carbon content of the gaseous fuel, from the fuel analysis results for month ''n'' (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

$(Feed)_n$ = Mass of sinter feed material in month ''n'' (metric tons).

$(C_{Feed})_n$ = Carbon content of the sinter feed material, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Sinter)_n$ = Mass of sinter produced in month ''n'' (metric tons).

$(C_{Sinter})_n$ = Carbon content of the sinter pellets, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(v) For EAFs, estimate CO_2 emissions using Equation Q–5 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star \Big[(Iron)_n \star (C_{Iron})_n + (Scrap)_n \star (C_{Scrap})_n + (Flux)_n \star (C_f)_n + (Electrode)_n \star (C_{Electrode})_n + (Carbon)_n \star (C_C) - (Steel)_n \star (C_{Steel})_n - (Slag)_n \star (C_{Slag})_n \qquad \text{(Eq. Q-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the EAF (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Iron)_n$ = Mass of direct reduced iron (if any) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Iron})_n$ = Carbon content of the molten iron, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Scrap)_n$ = Mass of ferrous scrap charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Scrap})_n$ = Average carbon content of the ferrous scrap, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Flux)_n$ = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Flux})_n$ = Average carbon content of the flux materials, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Electrode)_n$= Mass of carbon electrode consumed in month ‘‘n’’ (metric tons).

$(C_{Electrode})_n$ = Average carbon content of the carbon electrode, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Carbon)_n$ = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Carbon})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Steel)_n$ = Mass of molten steel produced by the furnace in month ‘‘n’’ (metric tons).

$(C_{Steel})_n$ = Average carbon content of the steel, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Slag)_n$ = Mass of slag produced by the furnace in month ‘‘n’’ (metric tons).

$(C_{Slag})_n$ = Average carbon content of the slag, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

(vi) For argon-oxygen decarburization vessels, estimate CO_2 emissions using Equation Q–6 of this section.

$$CO_2 = \sum_{1}^{12} \frac{44}{12} \star (Steel)_n \star [(C_{Steelin})_n - (C_{Steelout})_n] \qquad \text{(Eq. Q-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the argon-oxygen decarburization vessel (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Steel)_n$ = Mass of molten steel charged to the vessel in month ‘‘n’’ (metric tons).

$(C_{Steelin})_n$ = Carbon content of the molten steel before decarburization, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(C_{Steelout})_n$ = Average carbon content of the molten steel after decarburization, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$$\mathrm{CO}_2 = \sum_{1}^{12} \frac{44}{12} \star \Big[(F_g)_n \star (C_{gf})_n \star \frac{MW}{MVC} \star 0.001 + (Ore)_n \star (C_{ore}) + (Carbon)_n \star (C_{Carbon})_n + (Other)_n \star (C_{Other})_n - (Iron)_n \ (C_{Iron})_n - (NM)_n \star (C_{NM})_n \Big] \qquad \text{(Eq. Q-7)}$$

(vii) For direct reduction furnaces, estimate CO_2 emissions using Equation Q–7 of this section.

Where:

CO_2 = Annual CO_2 mass emissions from the direct reduction furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(F_g)_n$ = Volume of the gaseous fuel combusted on day ‘‘n’’ or in month ‘‘n’’, as applicable (scf).

$(C_{gf})_n$ = Average carbon content of the gaseous fuel, from the fuel analysis results for month ‘‘n’’ (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

$(Ore)_n$ = Mass of iron ore or iron ore pellets fed to the furnace in month ‘‘n’’ (metric tons).

$(C_{Ore})_n$ = Carbon content of the iron ore, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Carbon)_n$ = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Carbon})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Other)_n$ = Mass of other materials charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Other})_n$ = Average carbon content of the other materials charged to the furnace, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Iron)_n$ = Mass of iron produced in month ‘‘n’’ (metric tons).

$(C_{Iron})_n$ = Carbon content of the iron, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(NM)_n$ = Mass of non-metallic materials produced by the furnace in month ‘‘n’’ (metric tons).

$(C_{NM})_n$ = Average carbon content of the non-metallic materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(3) *Site-specific emission factor method.* You must conduct a performance test and measure CO_2 emissions from all exhaust stacks for the process and measure either the feed rate of materials into the process or the production rate during the test as described in paragraphs (a)(3)(i) through (iv) of this section.

(i) You must measure the production rate or feed rate, as applicable, during the test and calculate the average rate for the test period in metric tons per hour.

(ii) You must calculate the hourly CO_2 emission rate using Equation Q–8 and determine the average hourly CO_2 emission rate for the test.

$$CO_2 = 5.18\ x\ 10^{-7} \star C_{CO2} \star \mathrm{Q} \star \left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. Q-8)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).

5.18×10^{7} = Conversion factor (tons/scf-% CO_2).

C_{CO2} = Hourly CO_2 concentration (% CO_2).

Q = Hourly stack gas volumetric flow rate (scfh).

$\%H_2O$ = Hourly moisture percentage in the stack gas.

(iii) You must calculate a site-specific emission factor for the process in metric tons of CO_2 per metric ton of feed or production, as applicable, by dividing the average hourly CO_2 emission rate during the test by the average hourly feed or production rate during the test.

(iv) You must calculate CO_2 emissions for the process by multiplying the emission factor by the total amount of feed or production, as applicable, for the reporting period.

(b) You must determine emissions of CO_2 from the coke pushing process in $mtCO_2e$ by multiplying the metric tons of coal charged to the coke ovens during the reporting period by 0.008.

§ 98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of § 98.34(e).

(b) If you determine CO_2 emissions using the carbon balance procedure in § 98.173(a)(2), you must:

(1) For each process input and output other than fuels, determine the mass rate of each process input and output and record the totals for each process input and output for each calendar month. Determine the mass rate of fuels using the procedures for combustion units in § 98.34.

(2) For each process input and output other than fuels, sample each process input and output weekly and prepare a monthly composite sample for carbon analysis. For each process input that is a fuel, determine the carbon content using the procedures for combustion units in § 98.34.

(3) For each process input and output other than fuels, the carbon content must be analyzed by an independent certified laboratory using test method ASTM C25–06 (''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'').

(3) For each process input and output other than fuels, the carbon content must be analyzed by an independent certified laboratory using the test methods specified in this paragraph.

(A) Use ASTM C25–06 (''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'') for:

(i) Limestone, dolomite, and slag; ASTM D5373–08 (''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'') for coal, coke, and other carbonaceous materials; ASTM E1915–07a (''Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry'') for iron ore, taconite pellets, and other iron-bearing materials.

(ii) ASTM E1019–03 (''Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys'') for iron and ferrous scrap.

(iii) ASTM E1019–03 (''Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys''), ASTM CS–104 (''Carbon Steel of Medium Carbon Content''), ISO/TR 15349–1:1998 (''Unalloyed steel—Determination of low carbon content. Part 1''), or ISO/TR 15349–3: 1998 (''Unalloyed steel—Determination of low carbon content. Part 3'') as applicable for steel.

(c) If you determine CO_2 emissions using the site-specific emission factor procedure in § 98.173(a)(3), you must:

(1) Conduct an annual performance test under normal process operating conditions and at a production rate no less than 90 percent of the process rated capacity.

(2) For the furnace exhaust from basic oxygen furnaces, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces, sample the furnace exhaust for at least nine complete production cycles that start when the furnace is being charged and end after steel or iron and slag have been tapped. For EAFs that produce both carbon steel and stainless or specialty (low carbon) steel, develop an emission factor for the production of both types of steel.

(3) For taconite indurating furnaces, non-recovery coke batteries, and sinter processes, sample for at least 9 hours.

(4) Conduct the stack test using EPA Method 3A in 40 CFR part 60, Appendix A–2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F in appendix A–1 or Method 26, appendix A–2 of 40 CFR part 60 to determine the stack gas volumetric flow rate, and Method 4 in appendix A–3 of 40 CFR part 60 to determine the moisture content of the stack gas.

(5) Conduct a new performance test and calculate a new site-specific emission factor if your fuel type or fuel/feedstock mix changes, the process changes in a manner that affects energy efficiency by more than 10 percent, or the process feed materials change in a manner that changes the carbon content of the fuel or feed by more than 10 percent.

(6) The results of a performance test must include the analysis of samples, determination of emissions, and raw data. The performance test report must contain all information and data used to derive the emission factor.

(d) For CH_4, and N_2O emissions, you must meet the monitoring and QA/QC requirements of § 98.34.

(e) For a coke pushing process, determine the metric tons of coal charged to the coke ovens and record the totals for each pushing process for each calendar month. Coal charged to coke ovens can be measured using weigh belts or a combination of measuring volume and bulk density.

§ 98.175 Procedures for estimating missing data.

There are no allowances for missing data for facilities that estimate emissions using the carbon balance procedure in § 98.173(a)(2) or the site-emission factor procedure in § 98.133(a)(3); 100 percent data availability is required.

§ 98.176 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information required in paragraphs (a) through (g) of this section for coke pushing and for each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace, as applicable:

(a) Annual CO_2 emissions by calendar quarters.

(b) Annual total for all process inputs and outputs when the carbon balance is used for specific processes by calendar quarters (short tons).

(c) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel by calendar quarters.

(d) Production capacity (in tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(e) Annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces.

(f) Site-specific emission factor for all process units for which the site-specific emission factor approach is used.

(g) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36(d)(iv).

§ 98.177 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (f) of this section, as applicable.

(a) Annual CO_2 emissions as measured or determined for each calendar quarter.

(b) Monthly total for all process inputs and outputs for each calendar quarter when the carbon balance is used for specific processes.

(c) Monthly analyses of carbon content for each calendar quarter when the carbon balance is used for specific processes.

(d) Site-specific emission factor for all process units for which the site-specific emission factor approach is used.

(e) Annual production quantity for taconite pellets, coke, sinter, iron, and raw steel with records for each calendar quarter.

(f) Facilities must keep records that include a detailed explanation of how company records or measurements are used to determine all sources of carbon input and output and the metric tons of coal charged to the coke ovens (*e.g.*, weigh belts, a combination of measuring volume and bulk density). The owner or operator also must document the procedures used to ensure the accuracy of the measurements of fuel usage including, but not limited to, calibration of weighing equipment, fuel flow meters, coal usage including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.178 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart R—Lead Production

§ 98.180 Definition of the source category.

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. 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.

§ 98.181 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lead production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.182 GHGs to report.

(a) You must report the CO_2 process emissions from each smelting furnace used for lead production as required by this subpart.

(b) You must report the CO_2, CH_4, and N_2O emissions from each stationary combustion unit following the requirements specified in subpart C of this part.

§ 98.183 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must determine using the procedure specified in paragraphs (b)(1) and (2) of this section the total CO_2 emissions from the smelting furnaces at your facility used for lead production.

(1) For each smelting furnace at your facility used for lead production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into the smelting furnaces used at your facility for lead production for each calendar month and estimate total CO_2 process emissions from the affected units at your facility using Equation R–1 of this section. Carbon containing input materials include carbonaceous reducing agents.

$$E_{CO2} = \sum_{n=1}^{12} \frac{44}{12} \star \left[(Lead)_n \star (C_{Lead})_n + (Scrap)_n \star (C_{Scrap})_n + (Flux)_n \star (C_{Flux})_n + (Carbon)_n \star (C_{Carbon})_n + (Other)_n \star (C_{Other})_n \right] \qquad \text{(Eq. R-1)}$$

Where:

CO_2 = Total annual CO_2 process emissions from the individual smelting furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Lead)_n$ = Mass of lead ore charged to the smelting furnace in month ‘‘n’’ (metric tons).

$(C_{Lead})_n$ = Carbon content of the lead ore, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Scrap)_n$ = Mass of lead scrap charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Scrap})_n$ = Average carbon content of the lead scrap, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Flux)_n$ = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Flux})_n$ = Average carbon content of the flux materials, from the carbon analysis results for month ‘‘n’’ (percent by weight, expressed as a decimal fraction).

$(Carbon)_n$ = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month ‘‘n’’ (metric tons).

$(C_{Carbon})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Other)_n$ = Mass of any other materials charged to the furnace in month ''n'' (metric tons).

$(C_{Other})_n$ = Average carbon content of any other materials from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(2) You must determine the total CO_2 emissions from the smelting furnaces using Equation R–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. R-2)}$$

Where:

CO_2 = Total annual CO_2 emissions, metric tons/year.

E_{CO2_k} = Annual CO_2 emissions from smelting furnace k calculated using Equation R–1 of this subpart, metric tons/year.

k = Total number of smelting furnaces at facility used for the lead production.

§ 98.184 Monitoring and QA/QC requirements.

If you determine CO_2 emissions using the carbon input procedure in § 98.183(b), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing input material by direct measurement of the quantity of the material placed in the unit or by calculations using process operating information, and record the total mass for the material for each calendar month.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material for each calendar month using information provided by your material supplier or by collecting and analyzing a representative sample of the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory each calendar month using the test methods and their QA/QC procedures in § 98.7. Use ASTM E1941–04 (''Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys'') for analysis of lead bearing ore, lead scrap, and lead ingot; ASTM D5373–02 (''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'') for analysis of carbonaceous reducing agents, and ASTM C25–06 (''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'') for analysis of flux materials such as limestone or dolomite.

§ 98.185 Procedures for estimating missing data.

For the carbon input procedure in § 98.183(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations.

(a) For each missing value of the carbon content the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing records of the mass of carbon-containing input material consumption, the substitute data value shall be the best available estimate of the mass of the input material. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.186 Data Reporting Procedures.

In addition to the information required by § 98.3(c) of this part, each annual report must contain the information specified in paragraphs (a) through (e) of this section.

(a) Total annual CO_2 emissions from each smelting furnace operated at your facility for lead production (metric tons and the method used to estimate emissions).

(b) Facility lead product production capacity (metric tons).

(c) Annual facility production quantity (metric tons).

(d) Number of facility operating hours in calendar year.

(e) If you use the carbon input procedure, report for each carbon-containing input material consumed or used (other than fuel), the following information:

(1) Annual material quantity (in metric tons).

(2) Annual weighted average carbon content determined for material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.187 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section.

(a) Monthly facility production quantity for each lead product (in metric tons).

(b) Number of facility operating hours each month.

(c) If you use the carbon input procedure, record for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (c)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(d) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each smelting furnace. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.188 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart S—Lime Manufacturing

§ 98.190 Definition of the source category.

Lime manufacturing processes use a rotary lime kiln to produce a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) from limestone or dolomite by means of calcination. The lime manufacturing source category consists of marketed lime manufacturing facilities and non-marketed lime manufacturing facilities.

§ 98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lime manufacturing process and the facility meets the requirements of either § *98.2(a)(1) or (2).*

§ 98.192 GHGs to report.

(a) You must report CO_2 process emissions from each lime kiln as specified in this subpart.

(b) You must report CO_2, N_2O, and CH_4 emissions from fuel combustion at each lime kiln and any other stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.193 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you shall calculate CO_2 process emissions based on the production of each type of lime and calcined by-products/wastes produced at each kiln according to the procedures in paragraphs (b)(1) through (4) of this section.

(1) You must calculate a monthly emission factor for each kiln for each type of lime produced using Equation S–1 of this section. Calcium oxide and magnesium oxide content must be analyzed monthly for each kiln:

$$EF_{k,i} = \left(SR_{CaO,i} \times CaO_i\right) + \left(SR_{MgO,i} \times MgO_i\right) \qquad \text{(Eq. S-1)}$$

Where:

EF_k = Emission factor for kiln k for lime type i, metric tons CO_2/metric ton lime.

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for lime type i (see Table S–1 of this subpart), metric tons CO_2/ metric tons CaO.

SR_{MgO}= Stoichiometric ratio of CO_2 and MgO for lime type i (See Table S–1 of this subpart), metric tons CO_2/ metric tons MgO.

CaO_i= Calcium oxide content for lime type i determined according to § 98.194(b), metric tons CaO/ton lime.

MgO_i = Magnesium oxide content for lime type i determined according to § 98.194(b), metric tons MgO/ metric ton lime.

(2) You must calculate the correction factor for by-product/waste products at the kiln (monthly) using Equation S–2 of this section:

$$CF_{lkd,k} = 1 + \left(M_{d,i} / M_{lime,i}\right) \times C_{d,i} \times F_{d,i} \qquad \text{(Eq. S-2)}$$

Where:

$CF_{lkd,k}$ = Correction factor for by-products/ waste products (such as lime kiln dust, LKD) at kiln k.

$M_{d,i}$ = Weight of by-product/waste product not recycled to the kiln from lime type i, (tons of lime).

$M_{lime,i}$= Weight of lime produced at the kiln from lime type i, (tons of lime).

$C_{d,i}$ = Fraction of original carbonate in the LKD for lime type i, (fraction).

$F_{d,i}$ = Fraction of calcination of the original. carbonate in the LKD of lime type i, assumed to be 1.00 (fraction).

(3) You must calculate annual CO_2 process emissions for each kiln using Equation S–3 of this section:

$$E_k \sum_{\iota=1}^{\varphi} = \sum_{n}^{12} \left(EK_{k,n}\ M_{k,n}\ CF_{lkd,k,n}\right)\ 0.97)\ \frac{2000}{2205} \qquad \text{(Eq. S-3)}$$

Where:

E_k = Annual CO_2 process emissions from lime production at kiln k (metric tons/ year).

$EF_{k,n}$ = Emission factor for lime in calendar month n(tons CO_2/tons carbonate) from Equation S–1.

$M_{k,n}$ = Weight or mass of lime produced in calendar month n (tons/calendar month) from Equation S–3.

$CF_{lkd,k,n}$ = Correction factor for LKD for lime in calendar month n from Equation S–2.

0.97 = Default correction factor for the proportion of hydrated lime (Assuming 90 percent of hydrated lime produced is high-calcium lime with a water content of 28 percent).

2000/2205

= Conversion factor for tons to metric tons.

= Number of lime types produced at kiln k.

(4) You must determine the total CO_2 process emissions for the facility using Equation S–4 of this section:

$$CO_2 = \sum_{k=1}^{z} E_k \qquad \text{(Eq. S-4)}$$

Where:

CO_2 = Annual CO_2 process emissions from lime production (metric tons/year).

E_k = Annual CO_2 emissions from lime production at kiln k (metric tons/year).

z = Number of kilns for lime production.

§ 98.194 Monitoring and QA/QC requirements.

(a) Determine the quantity of each type of lime produced at each kiln and the quantity of each type of calcined by-product/waste produced for each lime type, such as LKD, at the kiln on a monthly basis. The quantity of each type of calcined by-product/waste produced at the kiln must include material that is sold or used in a product, inventoried, or disposed of. The quantity of lime types and LKD produced monthly by each kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(b) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime and each type of calcined by-product/ waste produced from each lime type by an off-site laboratory analysis on a monthly basis. This determination must be performed according to the requirements of ASTM C25–06, ‘‘Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime’’ (incorporated by reference—see § 98.7) and the procedures in ‘‘CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version’’, February 5, 2008 Revision (incorporated by reference—see § 98.7).

(c) You must use the most recent analysis of calcium oxide and magnesium oxide content of each lime product in monthly calculations.

(d) You must follow the quality assurance/quality control procedures (including documentation) in the National Lime Association's "CO_2 Emissions Calculation Protocol for the Lime Industry-English Units Version", February 5, 2008 Revision (incorporated by reference—see § 98.7).

§ 98.195 Procedures for estimating missing data.

For the procedure in § 98.193(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations.

(a) For each missing value of quantity of lime types, CaO and MgO content, and quantity of LKD the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing records of mass of raw material consumption, the substitute data value shall be the best available estimate of the mass of inputs. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.196 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a)(1) through (5) of this section for each lime kiln:

(1) Annual CO_2 process emissions;

(2) Annual lime production (in metric tons);

(3) Annual lime production capacity (in metric tons) per facility;

(4) All monthly emission factors, and;

(5) Number of operating hours in calendar year.

(b) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36.

§ 98.197 Records that must be retained.

(a) In addition to the records required by § 98.3(g), you must retain the following records specified in paragraphs (a)(1) through (4) of this section for each lime kiln:

(1) Annual calcined by-products/waste products (by lime type summed from monthly data.

(2) Lime production (by lime type) per month (metric tons).

(3) Calculation of emission factors.

(4) Results of chemical composition analysis (by lime product) per month.

(5) Monthly correction factors for by-products/waste products for each kiln.

(b) Facilities that use CEMS must also comply with the recordkeeping requirements specified in § 98.37.

§ 98.198 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE S–1 OF SUBPART S—BASIC PARAMETERS FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

Variable	Stoichiometric ratio
SR_{CaO}	0.7848
SR_{MgO}	1.0918

Subpart T—Magnesium Production

§ 98.200 Definition of source category.

The magnesium production and processing source category consists of the following facilities:

(a) Any site where magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations.

(b) Any site where molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

§ 98.201 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a magnesium production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.202 GHGs to report.

(a) You must report emissions of the following gases in kilograms and metric tons CO_2e per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

(1) Sulfur hexafluoride (SF_6).

(2) HFC–134a.

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

(4) Any other fluorinated GHGs.

(5) Carbon dioxide (CO_2).

(b) You must report CO_2, N_2O, and CH_4 emissions from each combustion unit on site by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§ 98.203 Calculating GHG emissions.

(a) Calculate CO_2e GHG emissions from magnesium production or processing using Equation T–1 of this section. For Equation T–1 of this section, use the procedures of either paragraph (b) or (c) of this section to estimate consumption of cover gas or carrier gas.

$$E_{GHG} = E_{SF6} + E_{134a} + E_{FK} + E_{CO2} + E_{OG} \qquad \text{(Eq. T-1)}$$

$$E_{SF6} = C_{SF6} \times 23.9$$

$$E_{134a} = C_{134a} \times 1.3$$

$$E_{FK} = C_{FK} \times 0.001$$

$$E_{CO_2} = C_{CO2} \times 0.001$$

$$E_{OG} = C_{OG} \times GWP_{OG}/1000$$

Where:

E_{GHG} = GHG emissions from magnesium production and processing ($mtCO_2e$).

E_{SF6} = SF_6 emissions from magnesium production and processing ($mtCO_2e$).

E_{134a} = HFC–134a emissions from magnesium production and processing ($mtCO_2e$).

E_{FK} = FK 5–1–12 emissions from magnesium production and processing ($\mathrm{mtCO_2e}$).
E_{CO2} = CO_2 emissions from magnesium production and processing ($\mathrm{mtCO_2e}$).
E_{OG} = Emissions of other fluorinated GHGs from magnesium production and processing ($\mathrm{mtCO_2e}$).
C_{SF6} = Consumption of SF_6 (kg).
C_{134a} = Consumption of HFC–134a (kg).
C_{FK} = Consumption of FK 5–1–12 (kg).
C_{CO2} = Consumption of CO_2 (kg).
C_{OG} = Consumption of other fluorinated GHGs (kg).
GWP_{OG} = The Global Warming Potential of the other fluorinated GHG provided in Table A–1 in subpart A of this part.

(b) To estimate consumption of cover gases or carrier gases by monitoring changes in container masses and inventories, consumption of each cover gas or carrier gas shall be estimated using Equation T–2 of this section:

$$C = I_B - I_E + A - D \qquad \text{(Eq. T-2)}$$

Where:

C = Consumption of any cover gas or carrier gas in kg over the period (e.g., 1 year).
I_B = Inventory of any cover gas or carrier gas stored in cylinders or other containers at the beginning of the period (e.g., 1 year), including heels, in kg.
I_E = Inventory of any cover gas or carrier gas stored in cylinders or other containers at the end of the period (e.g., 1 year), including heels, in kg.
A = Acquisitions of any cover gas or carrier gas during the period (e.g., 1 year) through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility, in kg.
D = Disbursements of cover gas or carrier gas to sources and locations outside the facility through sales or other transactions during the period, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas distributor, in kg.

(c) To estimate consumption of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, consumption of each cover gas or carrier gas shall be estimated using Equation T–3 of this section:

$$C_{GHG} = \sum_{p=1}^{n} Q_p \qquad \text{(Eq. T-3)}$$

Where:

C_{GHG} = The consumption of the cover gas over the period (kg).
Q_p = The mass of the cover gas used over the period (kg).
n = The number of periods in the year.

(d) For purposes of Equation T–3 of this section, the mass of the cover gas used over the period p shall be estimated by using Equation T–4 of this section:

$$Q_p = M_B - M_E \qquad \text{(Eq. T-4)}$$

Where:

Q_p = The mass of the cover gas used over the period (kg).
M_B = The mass of the contents of the cylinder at the beginning of period p.
M_E = The mass of the contents of the cylinder at the end of period p.

§ 98.204 Monitoring and QA/QC requirements.

(a) Consumption of cover gases and carrier gases may be estimated by monitoring the changes in container weights and inventories using Equation T–2 of this subpart, by monitoring the changes in individual container weights as the contents of each container are used using Equations T–3 and T–4 of this subpart, or by monitoring the mass flow of the pure cover gas or carrier gas into the cover gas distribution system. Consumption must be estimated at least annually.

(b) When estimating consumption by monitoring the mass flow of the pure cover gas or carrier gas into the cover gas distribution system, you must use gas flow meters with an accuracy of one percent of full scale or better.

(c) When estimating consumption using Equation T–2 of this subpart, you must ensure that all the quantities required by Equation T–2 of this subpart have been measured using scales or load cells with an accuracy of one percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier); however, you remain responsible for the accuracy of these masses and weights under this subpart.

(d) When estimating consumption using Equations T–3 and T–4 of this subpart, you must monitor and record container identities and masses as follows:

(1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.

(2) Ensure that all the quantities required by Equations T–3 and T–4 of this subpart have been measured using scales or load cells with an accuracy of one percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier (e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier); however, you remain responsible for the accuracy of these masses or weights under this subpart.

(e) All flowmeters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

§ 98.205 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the consumption of cover gases by multiplying magnesium production during the missing data period by the average cover gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover gas using Equation T–5 of this section:

$$R_{GHG} = C_{GHG} / Mg \qquad \text{(Eq. T-5)}$$

Where:

R_{GHG} = The usage rate for a particular cover gas over the period.
C_{GHG} = The consumption of that cover gas over the period (kg).
Mg = The magnesium produced or fed into the casting process over the period (metric tons).

§ 98.206 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must include the following information for the magnesium production and processing facility:

(a) Total GHG emissions for your facility by gas in metric tons and CO_2e.

(b) Type of production process (e.g. primary, secondary, die casting).

(c) Magnesium production amount in metric tons for each process type.

(d) Cover gas flow rate and composition.

(e) Amount of CO_2 used as a carrier gas during the reporting period.

(f) For any missing data, you must report the length of time the data were missing, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(g) The facility's cover gas usage rate.

(h) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased consumption).

(i) A description of any new melt protection technologies adopted to account for reduced GHG emissions in any given year.

§ 98.207 Records that must be retained.

In addition to the records specified in § 98.3(g), you must retain the following information for the magnesium production or processing facility:

(a) Check-out and weigh-in sheets and procedures for cylinders.

(b) Accuracy certifications and calibration records for scales.

(c) Residual gas amounts in cylinders sent back to suppliers.

(d) Invoices for gas purchases and sales.

§ 98.208 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart U—Miscellaneous Uses of Carbonate

§ 98.210 Definition of the source category.

(a) This source category consists of any equipment that uses limestone, dolomite, ankerite, magnesite, silerite, rhodochrosite, sodium carbonate, or any other carbonate in a manufacturing process.

(b) This source category does not include carbonates consumed for producing cement, glass, ferroalloys, iron and steel, lead, lime, pulp and paper, or zinc.

§ 98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.212 GHGs to report.

You must report CO_2 emissions aggregated for all miscellaneous carbonate use at the facility.

§ 98.213 Calculating GHG emissions.

Calculate process emissions of CO_2 using Equation U–1 of this section.

$$E_{CO_2} = \sum_{1}^{i} M_i \star EF_i \star F_i \star \frac{2000}{2205} \qquad \text{(Eq. U-1)}$$

Where:

ECO_2 = Annual CO_2 mass emissions from consumption of carbonates (metric tons).

M_i = Annual Mass of carbonate type i consumed (tons).

EF_i = Emission factor for the carbonate type i, as specified in Table U–1 to this subpart, metric tons CO_2/metric ton carbonate consumed.

F_i = Fraction calcination achieved for each particular carbonate type i.

i = number of the carbonate types.

2000/2205 = Conversion factor to convert tons to metric tons.

As an alternative to measuring the calcination fraction (F_i), a value of 1.0 can be used in Equation U–1 of this section.

§ 98.214 Monitoring and QA/QC requirements.

(a) The total mass of carbonate consumed can be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders, or purchase records.

(b) Determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis conducted by a certified laboratory using a suitable method such as using an x-ray fluorescence test or other enhanced testing method published by a consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ 98.215 Procedures for estimating missing data.

There are no missing data procedures for miscellaneous uses of carbonates. A complete record of all measured parameters used in the GHG emissions calculations is required. A re-test must be performed if the data from any measurements are determined to be invalid.

§ 98.216 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (d) of this section at the facility level.

(a) Annual CO_2 emissions from miscellaneous carbonate use (in metric tons).

(b) Annual carbonate consumption (by carbonate type in tons).

(c) Annual fraction calcinations.

(d) Average annual mass fraction of carbonate-based mineral in carbonate-based raw material by carbonate type.

§ 98.217 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section.

(a) Records of monthly carbonate consumption (by carbonate type). You must also document the procedures used to ensure the accuracy of monthly carbonate consumption.

(b) Annual chemical analysis of mass fraction of carbonate-based mineral in carbonate-based raw material by carbonate type.

(c) Records of all carbonate purchases and deliveries.

§ 98.218 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE U–1 OF SUBPART U—CO_2 EMISSION FACTORS FOR COMMON CARBONATES

Mineral name—carbonate	CO_2 emission factor (tons CO_2/ton carbonate)
Limestone—$CaCO_3$	0.43971
Magnesite—$MgCO_3$	0.52197
Dolomite—$CaMg(CO_3)_2$	0.47732
Siderite—$FeCO_3$	0.37987
Ankerite—$Ca(Fe,Mg,Mn)(CO_3)_2$	0.44197
Rhodochrosite—$MnCO_3$	0.38286
Sodium Carbonate/Soda Ash—Na_2CO_3	0.41492

Subpart V—Nitric Acid Production

§ 98.220 Definition of source category.

A nitric acid production facility uses oxidation, condensation, and absorption to produce a weak nitric acid (30 to 70 percent in strength).

§ 98.221 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a nitric acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.222 GHGs to report.

(a) You must report N_2O process emissions from each nitric acid production line as required by this subpart.

(b) You must report CO_2, CH_4, and N_2O emissions from each stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.223 Calculating GHG emissions.

You must determine annual N_2O process emissions from each nitric acid production line using a site-specific emission factor according to paragraphs (a) through (e) of this section.

(a) You must conduct an annual performance test to measure N_2O emissions from the absorber tail gas vent for each nitric acid production line. You must conduct the performance test(s) under normal process operating conditions.

(b) You must conduct the emissions test(s) using either EPA Method 320 in 40 CFR part 63, appendix A or ASTM D6348–03 incorporated by reference in § 98.7 to measure the N_2O concentration in conjunction with the applicable EPA Methods in 40 CFR part 60, Appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each.

(c) You must measure the production rate during the test(s) and calculate the production rate for the test period in tons (100 percent acid basis) per hour.

(d) You must calculate a site-specific emission factor for each nitric acid production line according to Equation V–1 of this section:

$$EF_{N_2O} = \frac{\sum_{1}^{n} \frac{C_{N_2O} = *1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. V-1)}$$

Where:

EF_{N2O} = Site-specific N_2O emissions factor (lb N_2O/ton nitric acid produced, 100 percent acid basis).

C_{N2O} = N_2O concentration during performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas (dscf/hr).

P = Production rate during performance test (tons nitric acid produced per hour (100 percent acid basis)).

n = Number of test runs.

(e) You must calculate N_2O emissions for each nitric acid production line by multiplying the emissions factor by the total annual production from that production line, according to Equation V–2 of this section:

$$E_{N_2O} = \frac{EF_{N2O} * P_a * (1 - DF_N) * AF_N}{2205} \qquad \text{(Eq. V-2)}$$

Where:

E_{N_2O} = N_2O mass emissions per year (metric tons of N_2O).

EF_{N_2O} = Site-specific N_2O emission factor for the production line (lb N_2O/ton acid produced, 100 percent acid basis).

P_a = Total production for the year from the production line (ton acid produced, 100 percent acid basis).

DF_N = Destruction factor of N_2O abatement technology, 'as specified by the abatement device manufacturer (percent of N_2O removed from air stream).

AF_N = Abatement factor of N_2O abatement technology (percent of year that abatement technology was used).

2205 = Conversion factor (lb/metric ton).

§ 98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new site-specific emissions factor at least annually. You must also conduct a new performance test whenever the production rate of a production line is changed by more than 10 percent from the production rate measured during the most recent performance test. The new emissions factor may be calculated using all available performance test data (i.e., averaged with the data from previous years), except in cases where process modifications have occurred or operating conditions have changed. Only the data consistent with the period after the changes were implemented shall be used.

(b) Each facility must conduct the performance test(s) according to a test plan and EPA Method 320 in 40 CFR part 63, Appendix A or ASTM D6348–03 (incorporated by reference—see § 98.7). All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. The report must include the items in paragraphs (b)(1) through (3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined. The production rate can be determined through sales records or by direct measurement using flow meters or weigh scales.

§ 98.225 Procedures for estimating missing data.

Procedures for estimating missing data are not provided for N_2O process emissions from nitric acid production lines. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 98.226 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (h) of this section for each nitric acid production line:

(a) Annual nitric acid production capacity (metric tons).

(b) Annual nitric acid production (metric tons).

(c) Number of operating hours in the calendar year (hours).

(d) Emission factor(s) used (lb N_2O/ton of nitric acid produced).

(e) Type of nitric acid process used.

(f) Abatement technology used (if applicable).

(g) Abatement utilization factor (percent of time that abatement system is operating).

(h) Abatement technology efficiency.

§ 98.227 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for each nitric acid production line:

(a) Records of significant changes to process.

(b) Annual test reports of N_2O emissions.

(c) Calculations of the site-specific emissions factor(s).

§ 98.228 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart W—Oil and Natural Gas Systems

§ 98.230 Definition of the source category.

This source category consists of the following facilities:

(a) Offshore petroleum and natural gas production facilities.

(b) Onshore natural gas processing facilities.

(c) Onshore natural gas transmission compression facilities.

(d) Underground natural gas storage facilities.

(e) Liquefied natural gas storage facilities.

(f) Liquefied natural gas import and export facilities.

§ 98.231 Reporting threshold.

You must report GHG emissions from oil and natural gas systems if your facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.232 GHGs to report.

(a) You must report CO_2 and CH_4 emissions in metric tons per year from sources specified in § 98.232(a)(1) through (23) at offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.

(1) Acid gas removal (AGR) vent stacks.

(2) Blowdown vent stacks.

(3) Centrifugal compressor dry seals.

(4) Centrifugal compressor wet seals.

(5) Compressor fugitive emissions.

(6) Compressor wet seal degassing vents.

(7) Dehydrator vent stacks.

(8) Flare stacks.

(9) Liquefied natural gas import and export facilities fugitive emissions.

(10) Liquefied natural gas storage facilities fugitive emissions.

(11) Natural gas driven pneumatic pumps.

(12) Natural gas driven pneumatic manual valve actuator devices.

(13) Natural gas driven pneumatic valve bleed devices.

(14) Non-pneumatic pumps.

(15) Offshore platform pipeline fugitive emissions.

(16) Open-ended lines (oels).

(17) Pump seals.

(18) Platform fugitive emissions.

(19) Processing facility fugitive emissions.

(20) Reciprocating compressor rod packing.

(21) Storage station fugitive emissions.

(22) Storage tanks.

(23) Storage wellhead fugitive emissions.

(24) Transmission station fugitive emissions.

(b) You must report the CO_2, CH_4, and N_2O emissions for stationary combustion sources, by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§ 98.233 Calculating GHG emissions.

(a) Estimate emissions using either an annual direct measurement, as specified in § 98.234, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.

(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources:

(1) Acid gas removal vent stacks.

(2) Natural gas driven pneumatic pumps.

(3) Natural gas driven pneumatic manual valve actuator devices.

(4) Natural gas driven pneumatic valve bleed devices.

(5) Blowdown vent stacks.

(6) Dehydrator vent stacks.

(c) A combination of engineering estimation described in this section and direct measurement described in § 98.234 shall be used to calculate emissions from the following fugitive emissions sources:

(1) Flare stacks.

(2) Storage tanks.

(3) Compressor wet seal degassing vents.

(d) You must use the methods described in § 98.234 (d) or (e) to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a). If fugitive emissions are detected, engineering estimation methods may be used for sources listed in paragraphs (b) and (c) of this section. If engineering estimation is used, emissions must be calculated using the appropriate method from paragraphs (d)(1) through (9) of this section:

(1) Acid gas removal vent stack. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate and weight.

(vii) If the acid gas removal unit is capturing CO_2 and transferring it off site, then refer to subpart OO of this part for calculating transferred CO_2.

(2) Natural gas driven pneumatic pump. Calculate fugitive emissions from a natural gas driven pneumatic pump as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pump model natural gas emission per unit volume of liquid pumped at operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas fugitive emissions for each pump using Equation W–1 of this section.

$$E_{s,n} = F_s * V \qquad \text{(Eq. W-1)}$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.

F_s = Natural gas driven pneumatic pump gas emission in ''emission per volume of liquid pumped at discharge pressure'' units at standard conditions, as provided by the manufacturer.

V = Volume of liquid pumped annually.

(D) Both CH_4 and CO_2 volumetric and mass fugitive emissions shall be calculated from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) If manufacturer data for F_s are not available, follow the method in § 98.234 (i)(1).

(3) Natural gas driven pneumatic manual valve actuator devices. Calculate fugitive emissions from a natural gas driven pneumatic manual valve actuator device as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas emission per actuation.

(B) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period.

(C) Calculate the natural gas fugitive emissions for each manual valve actuator using Equation W–2 of this section.

$$E_{s,n} = A_s * N \qquad \text{(Eq. W-2)}$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.

A_s = Natural gas driven pneumatic valve actuator natural gas emission in ''emission per actuation'' units at standard conditions, as provided by the manufacturer.

N = Number of times the pneumatic device was actuated in a way that vented natural gas to the atmosphere through the reporting period.

(D) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in § 98.234(i)(2) if manufacturer data are not available.

(4) Natural gas driven pneumatic valve bleed devices. Calculate fugitive emissions from a natural gas driven pneumatic valve bleed device as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas fugitive emissions for each valve bleed device using Equation W–3 of this section.

$$E_{s,n} = B_s * T \qquad \text{(Eq. W-3)}$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.

B_s = Natural gas driven pneumatic device bleed rate in ''emission per unit time'' units at standard conditions, as provided by the manufacturer.

T = Amount of time the pneumatic device has been operational through the reporting period.

(C) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in § 98.234(i)(3) if manufacturer data are not available.

(5) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:

(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (V_v in Equation W–4 of this subpart).

(ii) Retain logs of the number of blowdowns for each equipment type.

(iii) Calculate the total annual fugitive emissions using the following Equation W–4 of this section:

$$E_{a,n} = N * V_v \qquad \text{(Eq. W-4)}$$

Where:

$E_{a,n}$ = Natural gas fugitive emissions at ambient conditions from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.

(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(v) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(6) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using a simulation software packages, such as GLYCalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: Including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature, pressure, and composition.

(7) Flare stacks. Calculate fugitive emissions from a flare stack as follows:

(i) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares.

(ii) Calculate volume of natural gas sent to flare from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.

(iii) Calculate GHG volumetric fugitive emissions at actual conditions using Equation W–5 of this section:

$$E_{a,i} = V_a \times (1-\eta) \times X_i + (1-K) * \eta * V_a * Y_j * R_{j,i} \qquad \text{(Eq. W-5)}$$

Where:

$E_{a,i}$ = Annual fugitive emissions from flare stack.

V_a = Volume of natural gas sent to flare stack determined from § 98.234(j)(1).

η = Percent of natural gas combusted by flare (default is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares).

X_i = Concentration of GHG i in the flare gas determined from § 98.234(j)(1).

Y_j = Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).

$R_{j,i}$ = Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

K = ''1'' when GHG i is CH_4 and ''0'' when GHG i is CO_2.

(iv) Calculate GHG volumetric fugitive emissions at standard conditions using Equation W–6 of this section.

$$E_{s,i} = \frac{E_{a,i} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,i}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

$E_{a,i}$ = Natural gas volumetric fugitive emissions at actual conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(v) Calculate both CH_4 and CO_2 mass fugitive emissions from volumetric CH_4 and CO_2 fugitive emissions using calculations in paragraph (g) of this section.

(8) Storage tanks. Calculate fugitive emissions from a storage tank as follows:

(i) Calculate the total annual hydrocarbon vapor fugitive emissions using Equation W–7 of this section:

$$E_{a,h} = Q \times ER \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,h}$ = Hydrocarbon vapor fugitive emissions at actual conditions.

Q = Storage tank total annual throughput.

ER = Measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from § 98.234(j)(2).

(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation W–8 of this section.

$$E_{s,i} = E_{s,h} * M_i \qquad \text{(Eq. W-8)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

$E_{s,h}$ = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.

M_i = Mole percent of a particular GHG i in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with ASTM D1945–03.

(iv) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section.

(9) Compressor wet seal degassing vents. Calculate fugitive emissions from compressor wet seal degassing vents as follows:

(i) Calculate volume of natural gas sent to vent from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.

(ii) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(e) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure natural using Equation W–9 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \text{(Eq. W-9)}$$

Where:

$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

$E_{a,n}$ = Natural gas volumetric fugitive emissions at actual conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(f) Calculate GHG volumetric fugitive emissions at standard conditions as specified in paragraphs (f)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 fugitive emissions from natural gas fugitive emissions using Equation W–10 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. W-10)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard conditions.

M_i = Mole percent of GHG i in the natural gas.

(2) For Equation W–10 of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (f)(2)(i) through (vi) of this section.

(i) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.

(ii) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(v) GHG mole percent in natural gas stored in LNG storage facilities.

(vi) GHG mole percent in natural gas stored in LNG import and export facilities.

(g) Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation W–11 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i \qquad \text{(Eq. W-11)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass fugitive emissions at standard conditions.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

ρ_i = Density of GHG i;1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4.

§ 98.234 Monitoring and QA/QC requirements.

(a) You must use the methods described in paragraphs (d) or (e) in this section to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a), whether in operation or on standby. If fugitive emissions are detected for sources listed in paragraph (b) of this section, you must use the measurement methods described in paragraph(c) of this section to measure emissions from each source with fugitive emissions.

(b) You shall use detection instruments described in paragraphs (d) and (e) of this section to monitor the following fugitive emissions:

(1) Centrifugal compressor dry seals fugitive emissions.

(2) Centrifugal compressor wet seals fugitive emissions.

(3) Compressor fugitive emissions.

(4) LNG import and export facility fugitive emissions.

(5) LNG storage station fugitive emissions.

(6) Non-pneumatic pumps fugitive emissions.

(7) Open-ended lines (OELs) fugitive emissions.

(8) Pump seals fugitive emissions.

(9) Offshore platform pipeline fugitive emissions.

(10) Platform fugitive emissions.

(11) Processing facility fugitive emissions.

(12) Reciprocating compressor rod packing fugitive emissions.

(13) Storage station fugitive emissions.

(14) Transmission station fugitive emissions.

(15) Storage wellhead fugitive emissions.

(c) You shall use a high volume sampler, described in paragraph (f) of this section, to measure fugitive emissions from the sources detected in § 98.234(b), except as provided in paragraphs (c)(1) and (2) of this section:

(1) Where high volume samplers cannot capture all of the fugitive emissions, you shall use calibrated bags described in paragraph (g) of this section or meters described in paragraph (h) of this section to measure the following fugitive emissions:

(i) Open-ended lines (OELs).

(ii) Centrifugal compressor dry seals fugitive emissions.

(iii) Centrifugal compressor wet seals fugitive emissions.

(iv) Compressor fugitive emissions.

(v) Pump seals fugitive emissions.

(vi) Reciprocating compressor rod packing fugitive emissions.

(vii) Flare stacks and storage tanks, except that you shall use meters in combination with engineering estimation methods to calculate fugitive emissions.

(2) Use hot wire anemometer to calculate fugitive emissions from centrifugal compressor wet seal degassing vents and flares where it is unsafe or too high a flow rate to use calibrated bags.

(d) Infrared Remote Fugitive Emissions Detection.

(1) Use infrared fugitive emissions detection instruments that can identify specific equipment sources as emitting. Such instruments must have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere.

(2) If you are using instruments that visually display an image of fugitive emissions, you shall inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions at least once annually.

(3) If you are using any other infrared detection instruments, such as those based on infrared laser reflection, you shall monitor all potential emission points at least once annually.

(4) Perform fugitive emissions detection under favorable conditions, including but not limited to during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument.

(5) Use fugitive emissions detection and measurement instrument manuals to determine optimal operating conditions.

(e) Use organic vapor analyzers (OVAs) and toxic vapor analyzers (TVAs) for all fugitive emissions detection that are safely accessible at close-range.

(1) Check each potential emissions source, all joints, connections, and other potential paths to the atmosphere for emissions.

(2) Evaluate the lag time between the instrument sensing and alerting caused by the residence time of a sample in the probe shall be evaluated; upon alert, the instrument shall be slowly retraced over the source to pinpoint the location of fugitive emissions.

(3) Use Method 21 of 40 CFR part 60, appendix A–7, Determination of Volatile Organic Compound Leaks to calibrate OVAs and TVAs.

(f) Use a high volume sampler to measure only cold and steady emissions within the capacity of the instrument.

(1) A trained technician shall conduct measurements. The technician shall be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(g) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag.

(2) Perform three measurements of the time required to fill the bag; report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(e).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).

(5) Obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.

(h) Channel all emissions from a single source directly through the meter when using metering (e.g., rotameters, turbine meters, and others).

(1) Use an appropriately sized meter so that the flow does not exceed the full range of the meter in the course of measurement and conversely has sufficient momentum for the meter to register continuously in the course of measurement.

(2) Estimate natural gas volumetric fugitive emissions at standard conditions using calculations in § 98.233(f).

(3) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).

(4) Calibrate the meter using either one of the two methods provided as follows:

(i) Develop calibration curves by following the manufacturer's instruction.

(ii) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST). Determine correction factors for the flow meter according to the manufacturer's instructions. Record deviations from the correct reading at several flow rates. Plot the data points, comparing the flowmeter output to the actual flowrate as determined by the master weigh scale and use the difference as a correction factor.

(i) Where engineering estimation as described in § 98.233 is not possible, use direct measurement methods as follows:

(1) If manufacturer data on pneumatic pump natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. Determine the volume of liquid being pumped from the manufacturer's manual to provide the amount of natural gas emitted per unit of liquid pumped.

(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission per unit volume of liquid pumped at actual conditions into natural gas emission per pumping cycle at standard conditions using Equation W–9 of § 98.233.

(ii) Calculate annual fugitive emissions from the pump using Equation W–1, by replacing the manufacturer's data on emission (variable F_s) in the Equation with the standard conditions natural gas emission calculated in § 98.234(i)(1)(i).

(iii) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).

(2) If manufacturer data on pneumatic manual valve actuator device natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per actuation using a calibrated bag for each pneumatic device per actuation.

(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission at actual conditions into natural gas emission per actuation at standard conditions using Equation W–9 of this subpart.

(ii) Calculate annual fugitive emissions from the pneumatic device using Equation W–2 of this section, by replacing the manufacturer's data on emission (variable A_s) in the Equation with the standard conditions natural gas emission calculated in § 98.234(i)(2)(i).

(iii) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas fugitive emissions using the calculations in § 98.233(f) and (g).

(3) If manufacturer data on natural gas driven pneumatic valve bleed rate is not available, conduct a one-time measurement to determine natural gas bleed rate using a high volume sampler or calibrated bag or meter for each pneumatic device.

(i) Record natural gas conditions (temperature and pressure) to convert natural gas bleed rate at actual conditions into natural gas bleed rate at standard conditions using Equation W–9 of this subpart.

(ii) Calculate annual fugitive emissions from the pneumatic device using Equation W–3 of this subpart, by replacing the manufacturer's data on bleed rate (variable B) in the equation with the standard conditions bleed rate calculated in § 98.234(i)(3)(i).

(iii) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).

(j) Parameters for calculating emissions from flare stacks, compressor wet seal degassing vents, and storage tanks.

(1) Estimate fugitive emissions from flare stacks and compressor wet seal degassing vents as follows:

(i) Insert flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack or compressor wet seal degassing vent to determine the velocity of gas sent to flare or vent.

(ii) Record actual temperature and pressure conditions of the gas sent to flare or vent.

(iii) Sample representative gas to the flare stack or compressor wet seal degassing vent every quarter to evaluate the composition of GHGs present in the stream. Record the average of the most recent four gas composition analyses, which shall be conducted using ASTM D1945–03 (incorporated by reference, see § 98.7).

(2) Estimate fugitive emissions from storage tanks as follows:

(i) Measure the hydrocarbon vapor emissions from storage tanks using a flow meter described in paragraph (h) of this section for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.

(ii) Record the net (related to working loss) and gross (related to flashing loss) input of the storage tank during the test period.

(iii) Record temperature and pressure of hydrocarbon vapors emitted during the test period.

(iv) Collect a sample of hydrocarbon vapors for composition analysis

(k) Component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded from the requirements of this section.

(1) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero detection in the current reporting period and continuing until the fugitive emissions is repaired.

§ 98.235 Procedures for estimating missing data.

There are no missing data procedures for this source category. A complete record of all measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions measurements, you must repeat the measurement activity for those sources until a valid measurement is obtained.

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must report emissions data as specified in this section.

(a) Annual emissions reported separately for each of the operations listed in paragraphs (a)(1) through (6) of this section. Within each operation, emissions from each source type must be reported in the aggregate. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Offshore petroleum and natural gas production facilities.

(2) Onshore natural gas processing facilities.

(3) Onshore natural gas transmission compression facilities.

(4) Underground natural gas storage facilities.

(5) Liquefied natural gas storage facilities.

(6) Liquefied natural gas import and export facilities.

(b) Emissions reported separately for standby equipment.

(c) Emissions calculated for these sources shall assume no CO_2 capture and transfer off site.

(d) Activity data for each aggregated source type level for which emissions are being reported.

(e) Engineering estimate of total component count.

(f) Total number of compressors and average operating hours per year for compressors for each operation listed in paragraphs (a)(1) through (6) of this section.

(g) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (6) of this section.

(h) Specification of the type of any control device used, including flares, for any source type listed in 98.232(a).

(i) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.

(j) Detection and measurement instruments used.

§ 98.237 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected, whether quantification was made pursuant to § 98.234(k) and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

§ 98.238 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart X—Petrochemical Production

§ 98.240 Definition of the source category.

(a) The petrochemical production source category consists of any facility that produces acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol as an intended product, except as specified in paragraph (b) of this section.

(b) An integrated process is part of the petrochemical source category only if the petrochemical is the primary product of the integrated process.

§ 98.241 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petrochemical production process and the facility meets the requirements of either § *98.2(a)(1) or (2).*

§ 98.242 GHGs to report.

You must report the information in paragraphs (a) through (d) of this section:

(a) CO_2 emissions from each petrochemical process unit, following the methods and procedures in §§ 98.243 through 98.248. You must include the volume of any CO_2 captured from process off-gas in the reported CO_2 emissions.

(b) CO_2, CH_4, and N_2O emissions from stationary combustion units. For each stationary combustion unit, you must follow the calculation methods and other requirements specified in subpart C of this part. If you determine CO_2 process-based emissions in accordance with § 98.243(a)(2), then for each stationary combustion unit that burns off-gas from a petrochemical process, estimate CO_2, CH_4, and N_2O emissions for the combustion of supplemental fuel in accordance with subpart C of this part. In addition, estimate CH_4 and N_2O emissions from combusting off-gas according to the requirements in § 98.33(c)(2) and (3) using the emission factors for Refinery Gas in Table C–3 in subpart C of this part.

(c) CO_2 captured. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart PP of this part.

(d) CH_4 emissions for each on-site wastewater treatment system. For wastewater treatment systems, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart II of this part.

§ 98.243 Calculating GHG emissions.

(a) Determine process-based GHG emissions in accordance with the procedures specified in either paragraph (a)(1) or (2) of this section, and if applicable, comply with the procedures in paragraph (b) of this section.

(1) *Continuous emission monitoring system (CEMS).*

(i) If you operate and maintain a CEMS that measures total CO_2 emissions from process vents and combustion sources according to subpart C of this part, you must estimate total CO_2 emissions according to the Tier 4 Calculation Methodology requirements in § 98.33(a)(4). For each flare, estimate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b)(1) and (2).

(ii) If you elect to install CEMS to comply with this subpart, you must route all process vent emissions to one or more stacks and use a CEMS on each stack (except flare stacks) to measure CO_2 emissions. You must estimate total CO_2 emissions according to the Tier 4 Calculation Methodology requirements in § 98.33(a)(4). For each flare, estimate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b)(1) and (2) of subpart Y of this part.

(2) *Mass balance for each petrochemical process unit.* Estimate the emissions of CO_2 from each process unit, for each calendar week as described in paragraphs (a)(2)(i) through (v) of this section.

(i) Measure the volume of each gaseous and liquid feedstock and product continuously with a flow meter by following the procedures outlined in § 98.244(b)(2). Fuels used for combustion purposes are not considered to be feedstocks.

(ii) Measure the mass rate of each solid feedstock and product by following the procedures outlined in § 98.244(b)(1) and record the total for each calendar week.

(iii) Collect a sample of each feedstock and product at least once per week and determine the carbon content of each sample according to the procedures in § 98.244(b)(3).

(iv) If you determine that the weekly average concentration of a specific compound in a feedstock or product is always greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (a)(2)(iii) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average weekly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(v) Estimate CO_2 mass emissions for each petrochemical process unit using Equations X–1 through X–4 of this section:

$$C_g = \sum_{n=1}^{52} \sum_{i=1}^{j\,or\,k} \left[\left(F_{gf}\right)_{i,n} * \left(CC_{gf}\right)_{i,n} * \frac{\left(MW_f\right)_i}{MVC} - \left(P_{gp}\right)_{i,n} * \left(CC_{gp}\right)_{i,n} * \frac{\left(MW_p\right)_i}{MVC} \right] \qquad \text{(Eq. X-1)}$$

Where:

Cg = Annual net contribution to estimated emissions from carbon (C) in gaseous feedstocks (kilograms/year, kg/yr).

$(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in week ''n'' (standard cubic feet, scf).

$(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for week ''n'' (kg C per kg of feedstock).

$(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

$(P_{gp})_{i,n}$ = Volume of gaseous product i produced in week ''n'' (scf).

$(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i, including streams containing CO_2 recovered for sale or use in another process, for week ''n'' (kg C per kg of product).

$(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole).

j = Number of feedstocks.

k = Number of products.

$$C_l = \sum_{n=1}^{52} \sum_{i=1}^{j\,or\,k} \left(F_{lf}\right)_{i,n} * \left(CC_{lf}\right)_{i,n} - \left(P_{lp}\right)_{i,n} * \left(CC_{lp}\right)_{i,n} \qquad \text{(Eq. X-2)}$$

Where:

C_l = Annual net contribution to estimated emissions from carbon in liquid feedstocks (kg/yr).

$(F_{lf})_{i,n}$ = Volume of liquid feedstock i introduced in week ''n'' (gallons).

$(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for week ''n'' (kg C per gallon of feedstock).

$(P_{lp})_{i,n}$ = Volume of liquid product i produced in week ''n'' (gallons).

$(CC_{lp})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for week ''n'' (kg C per gallon of product).

$$C_s = \sum_{n=1}^{52} \sum_{i=1}^{j\ or\ k} \left(F_{sf}\right)_{i,n} * \left(CC_{sf}\right)_{i,n} - \left(P_{sp}\right)_{i,n} * \left(CC_{sp}\right)_{i,n} \Big] \qquad \text{(Eq. X-3)}$$

Where:

C_s = Annual net contribution to estimated emissions from carbon in solid feedstocks (kg/yr).

$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in week ''n'' (kg).

$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for week ''n'' (kg C per kg of feedstock).

$(P_{sp})_{i,n}$ = Mass of solid product i produced in week ''n'' (kg).

$(CC_{sp})_{i,n}$ = Average carbon content of solid product i in week ''n'' (kg C per kg of product).

$$CO_2 = 0.001 * \frac{44}{12} * \left(C_g + C_l + C_s\right) \qquad \text{(Eq. X-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and fuel gas combustion (metric tons/year).

0.001 = Conversion factor from kg to metric tons.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of carbon (C) (kg/kg-mole).

(b) If you have an integrated process unit that is determined to be part of the petrochemical production source category, comply with paragraph (a) of this section by including terms for additional carbon-containing products in Equations X–1 through X–3 of this section as necessary.

§ 98.244 Monitoring and QA/QC requirements.

(a) Each facility that uses CEMS to estimate emissions from process vents must comply with the procedures specified in § 98.34(e).

(b) Facilities that use the mass balance methodology in § 98.243(a)(2) must comply with paragraphs (b)(1) through (3) of this section.

(1) Measure the mass rate of each solid feedstock and product (e.g., using belt scales or weighing at the loadout points of your process unit) and record the total for each calendar week. You must document procedures used to ensure the accuracy of the measurements of the feedstock and product flows including, but not limited to, calibration of all weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices shall be recorded, and the technical basis for these estimates shall be recorded.

(2) Measure the volume of each gaseous and liquid feedstock and product for each process unit continuously with a flow meter. All feedstock and product flow meters must be calibrated prior to the first reporting year, using any applicable method incorporated by reference in § 98.7(b)(1) through (6), (c)(1), (f)(3)(i) through (ii), or (g)(1). You should use the flow meter accuracy test procedures in appendix D to part 75 of this chapter. Alternatively, calibration procedures specified by the equipment manufacturer may be used. Flow meters and gas composition monitors shall be recalibrated annually or at the frequency specified by another applicable rule or the manufacturer, whichever is more frequent.

(3) Collect a sample of each feedstock and product for each process unit at least once per week and determine the carbon content of each sample using an applicable ASTM method incorporated by reference in § 98.7(a)(15), (23), or (24). Alternatively, you may determine the composition of the sample using a gas chromatograph and then calculate the carbon content based on the composition and molecular weights for compounds in the sample. Determine the composition of gas and liquid samples using either: ASTM D1945–03 incorporated by reference in § 98.7 (a)(8) of subpart A of this part; ASTM D6060–96(2001) incorporated by reference in § 98.7; ASTM D2502–88(2004)e1 incorporated by reference in § 98.7; method UOP539–97 incorporated by reference in § 98.7; or EPA Method 18, 40 CFR part 60, appendix A–6; or Methods 8031, 8021, or 8015 in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication No. SW–846, Third Edition, September 1986, as amended by Update I, November 15, 1992. Calibrate the gas chromatograph using the procedures in the method prior to each use. For coal used as a feedstock, the samples for carbon content determinations shall be taken at a location that is representative of the coal feedstock used during the corresponding weekly period. For carbon black products, samples shall be taken of each grade or type of product produced during the weekly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed weekly or a composite of samples collected more frequently and analyzed weekly.

§ 98.245 Procedures for estimating missing data.

(a) For missing feedstock flow rates, product flow rates, and carbon contents, use the same procedures as for missing flow rates and carbon contents for fuels as specified in § 98.35.

(b) For missing CO_2 concentration, stack gas flow rate, and moisture content for CEMS on any process vent stack, follow the applicable procedures specified in § 98.35.

§ 98.246 Data reporting requirements.

(a) Facilities using the mass balance methodology in § 98.243(a)(2) must report the information specified in paragraphs (a)(1) through (9) of this section for each type of petrochemical produced, reported by process unit.

(1) Identification of the petrochemical process.

(2) Annual CO_2e emissions calculated using Equation X–4 of this subpart.

(3) Methods used to determine feedstock and product flows and carbon contents.

(4) Number of actual and substitute data points for each measured parameter.

(5) Annual quantity of each feedstock consumed.

(6) Annual quantity of each product and by-product produced, including all products from integrated processes that are part of the petrochemical production source category.

(7) Each carbon content measurement for each feedstock, product, and by-product.

(8) All calculations, measurements, equipment calibrations, certifications, and other information used to assess the uncertainty in emission estimates and the underlying volumetric flow rates, mass flow rates, and carbon contents of feedstocks and products.

(9) Identification of any combustion units that burned process off-gas.

(b) Each facility that uses CEMS to determine emissions from process vents must report the verification data specified in § 98.36(d)(1)(iv).

§ 98.247 Records that must be retained.

In addition to the recordkeeping requirements in § 98.3(g), you must retain the following records:

(a) The CEMS recordkeeping requirements in § 98.37, if you operate a CEMS on process vents.

(b) Results of feedstock or product composition determinations conducted in accordance with § 98.243(a)(2)(iv).

(c) Start and end times and calculated carbon contents for time periods when off-specification product is produced, if you comply with the alternative methodology in § 98.243(a)(2)(iv) for determining carbon content of feedstock or product.

§ 98.248 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Y—Petroleum Refineries

§ 98.250 Definition of source category.

(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(b) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; land disposal units; sulfur recovery plants. hydrogen plants (non-merchant plants only).

§ 98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.252 GHGs to report.

You must report:

(a) CO_2, CH_4, and N_2O combustion emissions from stationary combustion sources and from each flare. For each stationary combustion unit, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart C of this part.

(b) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit.

(c) CO_2 emissions from sour gas sent off site for sulfur recovery operations. You must follow the calculation procedures from § 98.253(f) of this subpart and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart of this part.

(d) CO_2 process emissions from each on-site sulfur recovery plant.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit.

(f) CO_2 emissions from asphalt blowing operations controlled using a combustion device and CH_4 emissions from asphalt blowing operations not controlled by a combustion device.

(g) CH_4 fugitive emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section.

(i) CH_4 emissions from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(j) CO_2 and CH_4 emissions from on-site wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart II of this part.

(k) CO_2 and CH_4 emissions from non-merchant hydrogen production. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§ 98.253 Calculating GHG emissions.

(a) For stationary combustion sources, if you operate and maintain a CEMS that measures total CO_2 emissions according to subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33(a)(4).

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with refinery fuel gas.

(1) Calculate the CO2 emissions according to the applicable requirements in paragraphs (b)(1)(i) through (iii) of this section.

(i) *Flow measurement.* If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational, to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) *Carbon content.* If you have a continuous higher heating value monitor or carbon content monitor on the flare or if you monitor these parameters at least daily, you must use the measured heat value or carbon content value in calculating the CO2 emissions from the flare. If you monitor carbon content, calculate the CO2 emissions from the flare using the applicable equation in § 98.33(a). If you monitor heat content, calculate the CO2 emissions from the flare using the applicable equation in § 98.33(a) and the default emission factor of 60 kilograms CO2/MMBtu on a higher heating value basis.

(iii) *Startup, shutdown, malfunction.* If you do not measure the higher heating value or carbon content of the flare gas at least daily, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO2 emissions as specified in paragraphs (b)(1)(iii)(A) through (C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.

(B) For periods of normal operation, use the average heating value measured for the refinery fuel gas for the heating value of the flare gas.

(C) Calculate the CO2 emissions using Equation Y–1 of this section.

$$CO_2 = Flare_N * HHV * (0.001 \ * EmF) + \sum_{p=1}^{n} \frac{44}{12} * \left(Flare_{SSM}\right)_p * (CC)_p \qquad \text{(Eq. Y-1)}$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (metric tons/year).
$Flare_N$ = Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).
HHV = Higher heating value for refinery fuel or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).
EmF = Default CO_2 emission factor of 60 kilograms CO_2/MMBtu (HHV basis).
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of start-up, shutdown, and malfunction events during the reporting year.
p = Start-up, shutdown, and malfunction event index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$Flare_{SSM}$ = Volume of flare gas combusted during a start-up, shutdown, or malfunctions from engineering calculations, (MMscf/event).
$(CC)_p$ = Average carbon content of the gaseous fuel, from the fuel analysis results or engineering calculations for the event (gram C per scf = metric tons C per MMscf).

(2) Calculate CH4 and N2O emissions according to the requirements in § 98.33(c)(2) using the emission factors for Refinery Gas in Table C–3 in subpart C of this part.

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (4) of this section.

(1) For catalytic cracking units and fluid coking units that use a continuous CO_2 CEMS for the final exhaust stack, calculate the combined CO_2 emissions from each catalytic cracking or fluid coking unit and CO boiler (if present) using the CEMS according to the Tier 4 Calculation Methodology requirements in § 98.33(a)(4). For units that do not have a CO boiler or other post-combustion device, Equation Y–3 of this section may be used as an alternative to a continuous flow monitor, if one is not already present.

(2) For catalytic cracking units and fluid coking units that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously monitor the O_2, CO, and CO_2 concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (iii) of this section:

(i) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y–2 of this section.

$$CO_2 = \sum_{1}^{n} \left(Q_r\right)_n * \frac{\left(\%CO_2 + \%CO\right)_n}{100\%} * \frac{44}{MVC} * 0.001 \qquad \text{(Eq. Y-2)}$$

Where:

CO_2 = Annual CO_2 mass emissions (metric tons/year).
Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).
$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
%CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.
44 = Molecular weight of CO_2 (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
0.001 = Conversion factor (metric ton/kg).
n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y–3 of this section.

$$Q_r = \frac{\left(79 * Q_a + \left(100 - \%O_{oxy}\right) * Q_{oxy}\right)}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. Y-3)}$$

Where:

Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
$\%O_2$ = Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
$\%O_{oxy}$ = O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
$\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
%CO = Hourly average percent CO concentration in the exhaust gas stream

from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.

(iii) If a CO boiler or other post-combustion device is used, calculate the GHG emissions from the fuel fired to the CO boiler or post-combustion device using the methods for stationary combustion sources in paragraph (a) of this section and report this separately for the combustion unit.

(3) Calculate CH_4 emissions using Equation Y–4 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_1}{EmF_2} \right) \qquad \text{(Eq. Y-4)}$$

Where:

CH_4 = Annual methane emissions from coke burn-off (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C–1 of subpart C of this part (kg CO_2/MMBtu).

EmF_2 = Default CH_4 emission factor for petroleum coke from Table C–3 of subpart C of this part (kg CH_4/MMBtu).

(4) Calculate N_2O emissions using Equation Y–5 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_1}{EmF_2} \right) \qquad \text{(Eq. Y-5)}$$

Where:

N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from Table C–1 of subpart C of this part (kg CO_2/MMBtu).

EmF_2 = Default N_2O emission factor for petroleum coke from Table C–3 of subpart C of this part (kg N_2O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part for combustion sources. Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using either the methods described in paragraphs (e)(1) or (2) of this section and calculate the CH_4 and N_2O emissions using the Equations Y–4 and Y–5 of this section, respectively.

(1) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using the methods in paragraphs (c)(1) or (2) of this section, or

(2) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation Y–6 of this section.

$$CO_2 = \sum_{1}^{n} \left(CB_Q \right)_n * CF * \frac{44}{12} * 0.001 \qquad \text{(Eq. Y-6)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

CB_Q = Coke burn-off quantity per regeneration cycle (kg coke/cycle).

CF = Site-specific fraction carbon content of produced coke, use 0.94 if site-specific fraction carbon content is unavailable (kg C per kg coke).

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

n = Number of regeneration cycles in the calendar year.

0.001 = Conversion factor (mt/kg).

(f) For on-site sulfur recovery plants, calculate CO_2 process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (4) of this section. Except as provided in paragraph (f)(4) of this section, combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part. For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(1) through (3) of this section is not considered a fuel.

(1) *Flow measurement.* If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(2) *Carbon content.* If you have a continuous compositional or carbon content monitor on the sour gas feed to the sulfur recovery plant or if you monitor these parameters on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor or use the default factor of 0.20.

(3) Calculate the CO_2 emissions from each sulfur recovery plant using Equation Y–7 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \qquad \text{(Eq. Y-7)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed to the sulfur recovery plant (scf/year).

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.

0.001 = Conversion factor, kg to metric tons.

(4) As an alternative to the monitoring methods in paragraphs (f)(1) through (3) of this section, you may use a continuous flow monitor and CO_2 CEMS in the final exhaust stack from the sulfur recovery plant according to the requirements in § 98.33(a)(4) to calculate the combined process and combustion emissions for the sulfur recovery plant. You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. You must report the process emissions from the sulfur recovery plant as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (3) of this section.

(1) For coke calcining units that use a continuous CO_2 CEMS for the final exhaust stack, calculate the combined CO_2 emissions from the coke calcining process and any auxiliary fuel combusted using the CEMS according to the requirements in § 98.33(a)(4).

(2) For coke calcining units that do not use a continuous CO_2 CEMS for the final exhaust stack, calculate CO_2 emissions from the coke calcining unit according to the requirements in paragraphs (g)(2)(i) and (ii) of this section.

(i) Calculate the CO_2 emissions for any auxiliary fuel fired to the calcining unit using the applicable methods in subpart C of this part.

(ii) Calculate the CO_2 emissions from the coke calcining process using Equation Y–8 of this section.

$$CO_2 = \frac{44}{12} * \left(M_{in} * CC_{GC} - \left(M_{out} + M_{dust}\right) * CC_{MPC}\right) \qquad \text{(Eq. Y-8)}$$

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

Min = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year).

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (g)(1) or (2), as applicable, and calculate CH_4 using Equation Y–4 of this section and N_2O emissions using Equation Y–5 of this section.

(h) For asphalt blowing operations, calculate GHG emissions according to the applicable provisions in paragraphs (h)(1) and (2) of this section.

(1) For uncontrolled asphalt blowing operations, calculate CH_4 emissions using Equation Y–9 of this section.

$$CH_4 = \left(Q_{AB} * EF_{AB} * \frac{16}{MVC} * 0.001\right) \qquad \text{(Eq. Y-9)}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB} = Emission factor for asphalt blowing from facility-specific test data (scf CH_4/MMbbl); use 2,555,000 scf CH_4/MMbbl if facility-specific test data are unavailable.

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(2) For controlled asphalt blowing operations, calculate CO_2 emissions using Equation Y–10 of this section, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section.

$$CO_2 = \left(Q_{AB} * EF_{AB} * \frac{44}{MVC} * 1 * 0.001\right) \qquad \text{(Eq. Y-10)}$$

Where:

CO_2 = Annual CO_2 emissions (metric ton/year).

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

EF_{AB} = Default emission factor (2,555,000 scf CH_4/MM bbl).

44 = Molecular weight of CO_2 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

1 = Assumed conversion efficiency (kg-mole CO_2/kg-mole CH_4).

0.001 = Conversion factor (metric tons/kg).

(i) For delayed coking units, calculate the CH_4 emissions from the depressurization of the coking unit vessel to atmosphere using the process vent method in paragraph (j) of this section and calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y–11 of this section.

$$CH_4 = \left(N * H * \frac{\pi * D^2}{4} * \frac{16}{MVC} * MF_{CH4} * 0.001\right) \qquad \text{(Eq. Y-11)}$$

Where:

CH_4 = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).

N = Total number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.

H = Height of coking unit vessel (feet).

D = Diameter of coking unit vessel (feet).

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_{CH4} = Mole fraction of methane in coking vessel gas (kg-mole CH_4/kg-mole gas); default value is 0.03.

0.001 = Conversion factor (metric ton/kg).

(j) For each process vent not covered in paragraphs (a) through (i) of this section, calculate GHG emissions using the Equation Y–12 of this section. You must use Equation Y–12 for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas.

$$E_x = \sum_{n=1}^{N} VR_n * MF_x * \frac{MW_x}{MVC} * VT_n * 0.001 \qquad \text{(Eq. Y-12)}$$

Where:

E_x = Annual emissions of each GHG from process vent (metric ton/yr).
N = Number of venting events per year.
VR_n = Volumetric flow rate of process vent (scf per hour per event).
44 = Molecular weight of CO_2 (kg/kg-mole).
MF_x = Mole fraction of GHG x in process vent.
MW_x = Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
VT_n = Venting time, (hours per event).
0.001 = Conversion factor (metric ton/kg)

(k) For uncontrolled blowdown systems, you must either use the methods for process vents in paragraph (j) of this section or calculate CH_4 emissions using Equation Y–13 of this section.

$$CH_4 = \left(Q_{Ref} * EF_{BD} * \frac{16}{MVC} * 0.001 \right) \qquad \text{(Eq. Y-13)}$$

Where:

CH_4 = Methane emission rate from blowdown systems (mt CH_4/year).
Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).
EF_{BD} = Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default is 137,000.
16 = Molecular weight of CH_4 (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
0.001 = Conversion factor (metric ton/kg).

(l) For equipment leaks, calculate CH_4 emissions using the method specified in either paragraph (l)(1) or (l)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA–453/R–95–017, NTIS PB96–175401).

(2) Use Equation Y–14 of this section.

$$CH_4 = \left(0.4 * N_{CD} + 0.2 * N_{PU1} + 0.1 * N_{PU2} + 4.3 * N_{H2} + 6 * N_{FGS} \right) \qquad \text{(Eq. Y-14)}$$

Where:

CH_4 = Annual methane emissions from fugitive equipment leaks (metric tons/year)
N_{CD} = Number of atmospheric crude oil distillation columns at the facility.
N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2} = Total number of hydrogen plants at the facility.
N_{FGS} = Total number of fuel gas systems at the facility.

(m) For storage tanks, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the TANKS Model (Version 4.09D) or estimate CH_4 emissions from storage tanks using Equation Y–15 of this section.

$$CH_4 = \left(0.1 * Q_{Ref} \right) \qquad \text{(Eq. Y-15)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).
0.1 = Default emission factor for storage tanks (metric ton CH_4/MMbbl).
Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y–16 of this section.

$$CH_4 = \left(995{,}000 * Q_{un} * \Delta P \right) * MF_{CH4} * \frac{16}{MVC} * 0.001 \qquad \text{(Eq. Y-16)}$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).
Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).
ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH4} = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000 = Correlation Equation factor (scf gas per MMbbl per psi)
16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).
0.001 = Conversion factor (metric ton/kg).

(n) For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP–42: ‘‘Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources’’. For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, report zero methane emissions.

§ 98.254 Monitoring and QA/QC requirements.

(a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(b) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(c) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in § 98.34(e).

§ 98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For each missing value of the heat content, carbon content, or molecular weight of the fuel, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing oil and gas flow rates, use the standard missing data procedures in section 2.4.2 of appendix D to part 75 of this chapter.

(c) For missing CO_2, CO, or O_2, CH_4, and N_2O concentrations, stack gas flow rate, and stack gas moisture content values, use the applicable initial missing data procedures in § 98.35 of subpart C of this part.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

(e) For petrochemical production units, use the missing data procedures in subpart X of this part.

(f) For on-site landfills, use the missing data procedures in subpart HH of this part.

(g) For on-site wastewater treatment systems, use the missing data procedures in subpart II of this part.

§ 98.256 Data reporting requirements.

In addition to the reporting requirements of § 98.3(c), you must report the information specified in paragraphs (a) through (e) of this section.

(a) For combustion sources, including flares, use the data reporting requirements in § 98.36.

(b) For hydrogen plants, use the data reporting requirements in subpart P of this part.

(c) For petrochemical production units, use the data reporting requirements in subpart X of this part.

(d) For on-site landfills, use the data reporting requirements in subpart HH of this part.

(e) For on-site wastewater treatment systems, use the data reporting requirements in subpart II of this part.

(f) For catalytic cracking units, traditional fluid coking units, catalytic reforming units, sulfur recovery plants, and coke calcining units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, catalytic reforming unit, sulfur recovery plant, or coke calcining unit).

(3) Maximum rated throughput of the unit, in bbl/stream day, metric tons sulfur produced/stream day, or metric tons coke calcined/stream day, as applicable.

(4) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and Equation number).

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or § 98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(h) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) The quantity of asphalt blown.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(i) For process vents subject to § 98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(j) For equipment leaks, storage tanks, uncontrolled blowdown systems, delayed coking units, and loading operations, the owner or operator shall report:

(1) The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(2) The method used to calculate equipment leak emissions and the

calculated, cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(3) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(4) The quantity of unstabilized crude oil received during the calendar year and the cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(6) The total number of delayed coking units at the facility, the number of delayed coking drums per unit, the dimensions and annual number of coke-cutting cycles for each drum, and the cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for delayed coking units.

(7) The quantity and types of materials loaded that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(8) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any.

(9) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.

(k) If you have a CEMS that measures CO_2 emissions but that is not required to be used for reporting GHG emissions under this subpart (i.e., a CO_2 CEMS on a process heater stack but the combustion emissions are calculated based on the fuel gas consumption), you must identify the emission source that has the CEMS and report the CO_2 emissions as measured by the CEMS for that emissions source.

§ 98.257 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records of all parameters monitored under § 98.255.

§ 98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Z—Phosphoric Acid Production

§ 98.260 Definition of the source category.

The phosphoric acid production source category consists of facilities with a wet-process phosphoric acid process line used to produce phosphoric acid. A wet-process phosphoric acid process line is any system of operation that manufactures phosphoric acid by reacting phosphate rock and acid.

§ 98.261 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a phosphoric acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.262 GHGs to report.

(a) You must report CO_2 process emissions from each wet-process phosphoric acid production line.

(b) You must report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit. You must follow the calculation methods and all other requirements of subpart C of this part.

§ 98.263 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in §§ 98.33(a) and 98.35.

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must calculate process emissions of CO_2 from each wet-process phosphoric acid process line using Equation Z–1 of this section:

$$E_m = \sum_{n=1}^{z} \frac{44}{12} * \left[IC_n * P_n\right] * \frac{2000}{2205} \qquad \text{(Eq. Z-1)}$$

Where:

E_m = Annual CO_2 mass emissions from a wet-process phosphoric acid process line m (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
IC_n = Inorganic carbon content of the batch of phosphate rock used during month n, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
P_n = Mass of phosphate rock consumed in month n by wet-process phosphoric acid process line m (tons).
m = Each wet-process phosphoric acid process line.
z = Number of months during which the process line m operates.
2000/2205 = Conversion factor to convert tons to metric tons.

(c) You must determine the total emissions from the facility using Equation Z–2 of this section:

$$CO_2 = \sum_{m=1}^{p} E_m \qquad \text{(Eq. Z-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from phosphoric acid production facility(metric tons/year)
E_m = Annual process CO_2 emissions from wet-process phosphoric acid process line m (metric tons/year)
p = Number of wet-process phosphoric acid process lines.

§ 98.264 Monitoring and QA/QC requirements.

(a) Determine the inorganic carbon content of each batch of phosphate rock consumed in the production of phosphoric acid using the applicable test method in section IX of the ''Book of Methods Used and Adopted by the Association of Florida Phosphate Chemists'', Seventh Edition, 1991.

(b) If more than one batch of phosphate rock is consumed in a month, use the highest inorganic carbon content measured during that month in Equation Z–1 of this subpart.

(c) Record the mass of phosphate rock consumed each month in each wet-process phosphoric acid process line.

§ 98.265 Procedures for estimating missing data.

There are no missing data procedures for wet-process phosphoric acid production facilities estimated according to § 98.263(b). A complete record of all measured parameters used in the GHG emissions calculations is required. A re-test must be performed if the data from the measurement are determined to be unacceptable.

§ 98.266 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section for each wet-process phosphoric acid production line:

(a) Annual phosphoric acid production by origin of the phosphate rock (metric tons).

(b) Annual phosphoric acid production by concentration of phosphoric acid produced (metric tons).

(c) Annual phosphoric acid production capacity.

(d) Annual arithmetic average percent inorganic carbon in phosphate rock from batch records.

(e) Annual average phosphate rock consumption from monthly measurement records (in metric tons).

§ 98.267 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (h) of this section for each wet-process phosphoric acid production facility:

(a) Total annual CO_2 emissions from all wet-process phosphoric acid process lines (in metric tons).

(b) Phosphoric acid production (by origin of the phosphate rock) and concentration.

(c) Phosphoric acid production capacity (in metric tons/year).

(d) Number of wet-process phosphoric acid process lines.

(e) Monthly phosphate rock consumption (by origin of phosphate rock).

(f) Measurements of percent inorganic carbon in phosphate rock for each batch consumed for phosphoric acid production.

(g) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(h) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption.

§ 98.268 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart AA—Pulp and Paper Manufacturing

§ 98.270 Definition of source category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), and operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (6) of this section:

(1) Chemical recovery furnaces at kraft and sodamills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals ($CaCO_3$, Na_2CO_3).

§ 98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (h) of this section:

(a) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2, biogenic CO_2, CH4, and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each semichemical chemical recovery combustion unit.

(d) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3).

(f) Emissions of CO_2, N_2O, and CH_4 from any other on-site stationary fuel combustion units (boilers, gas turbines, thermal oxiders, and other sources). You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(g) Emissions of CH_4 from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(h) Emissions of CH_4 from on-site wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart II of this part.

§ 98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (3) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO_2 emissions from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in § 98.33(a)(1).

(2) Calculate fossil fuel-based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c)(2) and (3).

(3) Calculate biogenic CO_2, CH_4, and N_2O emissions from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emissions factors, according to Equation AA–1 of this section:

$$CO_2, CH_4, or\ N_2O\ from\, biomass = \sum_{p=1}^{12} \left(1\, x 10^{-3}\right)(907)\,(Solids)_p * (HHV)_p * EF \qquad \text{(Eq. AA-1)}$$

Where:

CH_4, or N_2O, from Biomass = Biogenic CO_2, CH_4, or N_2O mass emissions from spent liquor solids combustion (metric tons).

$(Solids)_p$ = Mass of spent liquor solids combusted per month p (short tons per month).

$(HHV)_p$ = High heat value of the spent liquor solids for month p (mmBtu per mass).

EF = Default emission factor for CO_2, CH_4, or N_2O, from Table AA–1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

907 = Conversion factor from tons to kilograms.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1).

(2) Calculate CH_4 and N_2O emissions from fossil fuels from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c)(2).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA–2 of this section:

$$\text{Biogenic } CO_2 = \sum_{p=1}^{12} \frac{44}{12} * (\text{Solids})_p * (\text{CC})_p \qquad \text{(Eq. AA-2)}$$

Where:

Biogenic CO_2 = Annual CO_2 mass emissions for spent liquor solids combustion (metric tons).

$(\text{Solids})_p$ = Mass of the spent liquor solids combusted in month p (metric tons per month).

$(\text{CC})_p$ = Carbon content of the spent liquor solids, from the fuel analysis results for the month p (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(4) Calculate CH_4 and N_2O emissions from biomass using Equation AA–1 and the default CH_4 and N_2O emissions factors for kraft facilities in Table AA–1 of this subpart and convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.2(b)(4).

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (3) of this section:

(1) Calculate CO_2 emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1); use the default HHV listed in Table C–1 of subpart C of this part and the default CO_2 emissions factors listed in Table AA–2 of this subpart.

(2) Calculate CH_4 and N_2O emissions from fossil fuel from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c)(2) and (3); use the default HHV listed in Table C–1 of subpart C of this part and the default CH_4 and N_2O emissions factors listed in Table AA–2 of this subpart.

(3) Biogenic CO_2 emissions from conversion of CaCO3 to CaO are calculated as part of the chemical recovery furnace biogenic CO_2 estimates in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to Equation AA–3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000\ kg/metric\ ton \qquad \text{(Eq. AA-3)}$$

Where:

CO_2 = CO_2 mass emissions from makeup chemicals (kilograms/yr).

M $(caCO_3)$ = Make-up quantity of $CaCO_3$ used for the reporting year (metric tons).

M $(NaCO_3)$ = Make-up quantity of Na_2CO_3 used for the reporting year (metric tons).

44 = Molecular weight of CO_2.

180 = Molecular weight of $CaCO_3$.

105.99 = Molecular weight of Na_2CO_3.

§ 98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in § 98.34. All QA/QC data must be available for inspection upon request.

(b) High heat values of black liquor must be determined once per month using TAPPI Method T 684. The mass of spent black liquor solids must be determined once per month using TAPPI Method T 650. Carbon analyses for spent pulping liquor must be determined once per month using ASTM method D5373–08.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel and makeup chemical usage, including, but not limited, to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§ 98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

(b) For missing spent pulping liquor flow rates, use the lesser value of either the maximum fuel flow rate for the combustion unit, or the maximum flow rate that the fuel flow meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.276 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information in paragraphs (a) through (e) of this section for each GHG emission unit listed in § 98.270(b).

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, and N_2O presented by calendar quarter.

(b) Total consumption of all biomass fuels by calendar quarter.

(c) Total annual quantity of spent liquor solids fired at the facility by calendar quarter.

(d) Total annual steam purchases.

(e) Total annual quantities of makeup chemicals (carbonates) used.

§ 98.277 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records in paragraphs (a) through (h) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2) by calendar quarter for each emissions source listed under § 98.270(b) of this subpart.

(b) Monthly total consumption of all biomass fuels for each biomass combustion unit.

(c) Monthly analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(d) Monthly analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(e) Monthly quantities of spent liquor solids fired in each chemical recovery furnace and chemical recovery combustion unit.

(f) Monthly and annual steam purchases.

(g) Monthly and annual steam production for each biomass combustion unit.

(h) Monthly quantities of makeup chemicals used.

§ 98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE AA–1 OF SUBPART AA—KRAFT PULPING LIQUOR EMISSIONS FACTORS FOR BIOMASS-BASED CO_2, CH_4, AND N_2O

Wood furnish	Biomass-based emissions factors (kg/mmBtu HHV)		
	CO_2[a]	CH_4	N_2O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		
Straw	95.1		

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

TABLE AA–2 OF SUBPART AA—KRAFT LIME KILN AND CALCINER EMISSIONS FACTORS FOR FOSSIL FUEL-BASED CO_2, CH_4, AND N_2O

Fuel	Fossil fuel-based emissions factors (kg/mmBtu HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5	....	....	73.5	....	0.0004
Natural Gas	56.0	....	....	56.0	....	0.0001
Biogas	0	....	....	0	....	0.0001

Subpart BB—Silicon Carbide Production

§ 98.280 Definition of the source category.

Silicon carbide production includes any process that produces silicon carbide for abrasive purposes.

§ 98.281 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a silicon carbide production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.282 GHGs to report.

(a) You must report CO_2 and CH_4 process emissions from all silicon carbide process units combined, as set forth in this subpart.

(b) You must report CO_2, N_2O, and CH_4 emissions from each stationary combustion unit by following all of the requirements of subpart C of this part.

§ 98.283 Calculating GHG emissions.

You must determine CO_2 emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements of § 98.33(b)(5)(iii)(A), (B), and (C), you must estimate total CO_2 emissions according to the requirements for the Tier 4 Calculation Methodology in § 98.33(a)(4).

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must calculate the annual process CO_2 emissions from all silicon carbide production processes at the facility combined, using a facility-specific emission factor according to the procedures in paragraphs (b)(1) and (2) of this section.

(1) Use Equation BB–1 of this section to calculate the facility-specific emissions factor for determining CO_2 emissions. The carbon content must be

determined quarterly and used to calculate a quarterly CO_2 emisssions factor:

$$EF_{CO2} = 0.65 * CCF * \left(\frac{44}{12}\right) \qquad \text{(Eq. BB-1)}$$

Where:

EF_{CO2} = CO_2 emissions factor (metric tons CO_2/metric ton of petroleum coke consumed).

0.65 = Adjustment factor for the amount of carbon in silicon carbide product (assuming 35 percent of carbon input is in the carbide product).

CCF = Carbon content factor of petroleum coke from the supplier or as measured by the applicable method incorporated by reference in § 98.7.

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation BB–2 of this section to calculate CO_2 process emissions (quarterly) from all silicone carbide production:

$$CO_2 = \sum_{n=1}^{q}\left[T_n * EF_{CO2,n}\right] * \frac{2000}{2205} \qquad \text{(Eq. BB-2)}$$

Where:

CO_2 = Annual CO_2 mass production emissions (metric tons CO_2/year).

T_n = Petroleum coke consumption in calendar quarter n (tons coke).

$EF_{CO2,\,n}$ = CO_2 emissions factor from calendar quarter n (calculated in Equation BB–1 of this section).

2000/2205 = Conversion factor to convert tons to metric tons.

q = Number of quarters.

(c) You must determine annual process CH_4 emissions from all silicon carbide production processes combined using Equation BB–3 of this section:

$$CH_4 = \sum_{n=1}^{q}\left[T_n * 10.2\right] * \frac{2000}{2205} * 0.001 \qquad \text{(Eq. BB-3)}$$

Where:

CH_4 = Annual CH_4 mass emissions (metric tons CH_4, year).

T_n = Petroleum coke consumption in calendar quarter n (tons coke).

10.2 = CH_4 emissions factor (kg CH_4/metric ton coke).

2000/2205 = Conversion factor to convert tons to metric tons.

0.001 = Conversion factor from kilograms to metric tons.

q = Number of quarters.

§ 98.284 Monitoring and QA/QC requirements.

(a) You must determine the quantity of petroleum coke consumed each quarter (tons coke/quarter).

(b) For CO_2 process emissions, you must determine the carbon content of the petroleum coke for four calendar quarters per year based on reports from the supplier or by measurement of the carbon content by an off-site laboratory using the applicable test method incorporated by reference in § 98.7.

§ 98.285 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. There are no missing value provisions for the carbon content factor or coke consumption. A re-test must be performed if the data from the quarterly carbon content measurements are determined to be unacceptable or not representative of typical operations.

§ 98.286 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section.

(a) Annual CO_2 and CH4 emissions from all silicon carbide production processes combined (in metric tons).

(b) Annual production of silicon carbide (in metric tons).

(c) Annual capacity of silicon carbide production (in metric tons).

(d) Annual operating hours.

(e) Quarterly facility-specific emission factors.

§ 98.287 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for all silicon carbide production processes combined.

(a) Annual consumption of petroleum coke (in metric tons).

(b) Quarterly analyses of carbon content for consumed coke (averaged to an annual basis).

(c) Quarterly facility-specific emission factor calculations.

§ 98.288 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart CC—Soda Ash Manufacturing

§ 98.290 Definition of the source category.

A soda ash manufacturing facility is any facility with a manufacturing line that calcines trona to produce soda ash.

§ 98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.292 GHGs to report.

(a) You must report CO_2 process emissions from each soda ash manufacturing line as required in this subpart.

(b) You must report the CO_2, N_2O, and CH_4 emissions from fuel combustion at each kiln and from each stationary combustion unit by following the requirements of subpart C of this part.

§ 98.293 Calculating GHG emissions.

You must determine CO_2 emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) Any soda ash manufacturing line that meets the conditions specified in § 98.33(b)(5)(iii)(A),(B), and (C), or § 98.33(b)(5)(ii)(A) through (F) shall calculate total CO_2 emissions using a continuous emissions monitoring system according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If the facility does not measure total emissions with a CEMS, you must determine the total process emissions from the facility using Equation CC–1 of this section:

$$CO_2 = \sum_{k=1}^{n} E_k \qquad \text{(Eq. CC-1)}$$

Where:

CO_2 = Annual process CO_2 emissions from soda ash manufacturing facility (metric tons/year).

E_k = Annual CO_2 process emissions from each calciner (kiln), k (in metric tons/year), using either Equation CC–2 or CC–3.

n = Number of calciners (kilns) located at the facility.

(c) Calculate the annual CO_2 process emissions from each kiln using either Equation CC–2 or CC–3 of this section.

$$CO_2 = \sum_{n=1}^{12} \frac{44}{12} \star \left[\left(IC_T\right)_n \star \left(T_t\right)_n \right] \star \frac{2000}{2205} \star \frac{0.097}{1} \qquad \text{(Eq. CC-2)}$$

$$CO_2 = \sum_{n=1}^{12} \frac{44}{12} \star \left[\left(ICsa\right)_n \star \left(Tsa\right)_n \right] \star \frac{2000}{2205} \star \frac{0.138}{1} \qquad \text{(Eq. CC-3)}$$

Where:

CO_2 = Annual CO_2 process emissions (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(IC_T)_n$ = Inorganic carbon content in trona input, from the carbon analysis results for month n (percent by weight, expressed as a decimal fraction).

$(IC_{sa})_n$ = Inorganic carbon content in soda ash output, from the carbon analysis results for month n (percent by weight, expressed as a decimal fraction).

$(T_t)_n$ = Mass of trona input in month n (tons).

$(T_{sa})_n$ = Mass of soda ash output in month n (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

0.097/1 = Ratio of ton of CO_2 emitted for each ton of trona.

0.138/1 = Ratio of ton of CO_2 emitted for each ton of natural soda ash produced.

§ 98.294 Monitoring and QA/QC requirements.

(a) You must determine the inorganic carbon content of the trona or soda ash on a daily basis and determine the monthly average value for each soda ash manufacturing line.

(b) If you calculate CO_2 process emissions based on trona input, you must determine the inorganic carbon content of the trona using a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method (utilizing ASTM D4839–03).

(c) If you calculate CO_2 process emissions based on soda ash production, you must determine the inorganic carbon content of the soda ash using ASTM E359–00 (2005). The inorganic carbon content of soda ash can be directly expressed as the total alkalinity of the soda ash.

(d) You must measure the mass of trona input or soda ash produced by each soda ash manufacturing line on a monthly basis using either belt scales or by weighing the soda ash at the truck or rail loadout points of your facility.

(e) You must keep a record of all trona consumed and soda ash production. You also must document the procedures used to ensure the accuracy of the monthly measurements of trona consumed soda ash production.

§ 98.295 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. There are no missing value provisions for the carbon content of trona or soda ash. A re-test must be performed if the data from the daily carbon content measurements are determined to be unacceptable.

§ 98.296 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (f) of this section for each soda ash manufacturing line.

(a) Annual CO_2 process emissions (metric tons).

(b) Number of soda ash manufacturing lines.

(c) Annual soda ash production (metric tons) and annual soda ash production capacity.

(d) Annual consumption of trona from monthly measurements (metric tons).

(e) Fractional purity (i.e., inorganic carbon content) of trona or soda ash (by daily measurements and by monthly average) depending on the components used in Equation CC–2 or CC–3 of this subpart).

(f) Number of operating hours in calendar year.

§ 98.297 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each soda ash manufacturing line.

(a) Monthly production of soda ash (metric tons).

(b) Monthly consumption of trona (metric tons).

(c) Daily analyses for inorganic carbon content of trona or soda ash (as fractional purity), depending on the components used in Equation CC–2 or CC–3 of this subpart.

(d) Number of operating hours in calendar year.

§ 98.298 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart DD—Sulfur Hexafluoride (SF_6) From Electrical Equipment

§ 98.300 Definition of the source category.

The electric power system source category includes electric power transmission and distribution systems that operate gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers containing sulfur-hexafluoride (SF6) or perfluorocarbons (PFCs).

§ 98.301 Reporting threshold.

You must report GHG emissions from electric power systems if the total nameplate capacity of SF_6 and PFC containing equipment in the system exceeds 17,820 lbs (7,838 kg).

§ 98.302 GHGs to report.

You must report total SF_6 and PFC emissions (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) from the following types of equipment:

(a) Gas-insulated substations.

(b) Circuit breakers.

(c) Switchgear.

(d) Gas-insulated lines.

(d) Electrical transformers.

§ 98.303 Calculating GHG emissions.

(a) For each electric power system, you must estimate the annual SF_6 and PFC emissions using the mass-balance approach in Equation DD–1 of this section:

$$\text{User Emissions} = (\text{Decrease in } SF_6 \text{ Inventory}) + (\text{Acquisitions of } SF_6) - (\text{Disbursements of } SF_6) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated}) \qquad \text{(Eq. DD-1)}$$

Where:

Decrease in SF_6 Inventory = (SF_6 stored in containers, but not in equipment, at the beginning of the year)—(SF_6 stored in containers, but not in equipment, at the end of the year).

Acquisitions of SF_6 = (SF_6 purchased from chemical producers or distributors in bulk) + (SF_6 purchased from equipment manufacturers or distributors with or inside equipment) + (SF_6 returned to site after off-site recycling).

Disbursements of SF_6 = (SF_6 in bulk and contained in equipment that is sold to other entities) + (SF_6 returned to suppliers) + (SF_6 sent off site for recycling) + (SF_6 sent to destruction facilities).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment)—(Nameplate Capacity of retiring equipment). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.)

(b) The mass-balance method in paragraph (a) of this section shall be used to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF_6 in equation DD–1.

§ 98.304 Monitoring and QA/QC requirements.

(a) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to Equation DD–1 to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the Decrease in SF_6 Inventory and the Net Increase in Total Nameplate Capacity may be calculated as negative numbers.

(3) Ensure that beginning-of-year inventory matches end-of-year inventory from the previous year.

(4) Ensure that in addition to SF_6 purchased from bulk gas distributors, SF_6 purchased from Original Equipment Manufacturers (OEM) and SF_6 returned to the facility from off-site recycling are also accounted for among the total additions.

(b) Ensure the following QA/QC methods are employed throughout the year:

(1) Ensure that cylinders returned to the gas supplier are consistently weighed on a scale that is certified to be accurate and precise to within 1 percent of the true weight and is periodically recalibrated per the manufacturer's specifications. Either measure residual gas (the amount of gas remaining in returned cylinders) or have the gas supplier measure it. If the gas supplier weighs the residual gas, obtain from the gas supplier a detailed monthly accounting, within 1 percent, of residual gas amounts in the cylinders returned to the gas supplier.

(2) Ensure that procedures are in place and followed to track and weigh all cylinders as they are leaving and entering storage. Cylinders shall be weighed on a scale that is certified to be accurate to within 1 percent of the true weight and the scale shall be recalibrated at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. All scales used to measure quantities that are to be reported under § 98.306 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ISWM, ISDA, NCWM, or others). Alternatively, calibration procedures specified by the scale manufacturer may be used. Calibration shall be performed prior to the first reporting year.

(3) Ensure all substations have provided information to the manager compiling the emissions report (if it is not already handled through an electronic inventory system).

§ 98.305 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF_6 and PFC, and from similar equipment repair, replacement, and maintenance operations.

§ 98.306 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each electric power system, by chemical:

(a) Nameplate capacity of equipment containing SF_6 and nameplate capacity of equipment containing each PFC:

(1) Existing as of the beginning of the year.

(2) New during the year.

(3) Retired during the year.

(b) Transmission miles (length of lines carrying voltages at or above 34.5 kV).

(c) SF_6 and PFC sales and purchases.

(d) SF_6 and PFC sent off site for destruction.

(e) SF_6 and PFC sent off site to be recycled.

(f) SF_6 and PFC returned from off site after recycling.

(g) SF_6 and PFC stored in containers at the beginning and end of the year.

(h) SF_6 and PFC with or inside new equipment purchased in the year.

(i) SF_6 and PFC with or inside equipment sold to other entities.

(j) SF_6 and PFC returned to suppliers.

§ 98.307 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain records of the information reported and listed in § 98.306.

§ 98.308 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart EE—Titanium Dioxide Production

§ 98.310 Definition of the source category.

The titanium dioxide production source category consists of facilities that use the chloride process to produce titanium dioxide.

§ 98.311 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a titanium dioxide production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.312 GHGs to report.

(a) You must report CO_2 process emissions from each chloride process line as required in this subpart.

(b) Report the CO_2, N_2O, and CH_4 emissions from each stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.313 Calculating GHG emissions.

You must determine CO_2 emissions for each process line in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) If the facility operates and maintains a continuous emission monitoring system (CEMS) that meets the conditions specifed in § 98.33(b)(5)(ii) or (iii), then you must calculate total CO_2 emissions using the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If the facility does not measure total emissions with a CEMS, you must calculate the process CO_2 emissions for each calcined petroleum coke process line by determining the mass of calcined petroleum coke consumed in line. Use Equation EE–1 of this section to calculate annual CO_2 process emissions for each process line:

$$E_p = \sum_{n=1}^{12} \frac{44}{12} * C_n * \frac{2000}{2205} \qquad \text{(Eq. EE-1)}$$

Where:

E_p = Annual CO_2 mass emissions from each chloride process line (metric tons).

C_n = Calcined petroleum coke consumption in month n, tons.

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion of tons to metric tons.

(c) You must determine the total CO_2 process emissions from the facility using Equation EE–2 of this section:

$$CO_2 = \sum_{p-1}^{n} E_p \qquad \text{(Eq. EE-2)}$$

Where:

CO_2 = Annual CO_2 emissions from titanium dioxide production facility (metric tons/year).

E_p = Annual CO_2 emissions from each chloride process line, p (in metric tons/year), determined using Equation EE–1.

n = Number of separate chloride process lines located at the facility.

§ 98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke either by weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly calcined petroleum coke consumption.

§ 98.315 Procedures for estimating missing data.

There are no missing data procedures for the measurement of petroleum coke consumption. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 98.316 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information specified in paragraphs (a) through (e) for each titanium dioxide production line.

(a) Annual CO_2 emissions (metric tons).

(b) Annual consumption of calcined petroleum coke (metric tons).

(c) Annual production of titanium dioxide (metric tons).

(d) Annual production capacity of titanium dioxide (metric tons).

(e) Annual operating hours for each titanium dioxide process line.

§ 98.317 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the following records specified in paragraphs (a) through (e) of this section for each titanium dioxide production facility.

(a) Monthly production of titanium dioxide (metric tons).

(b) Production capacity of titanium dioxide (metric tons).

(c) Records of all calcined petroleum coke purchases.

(d) Records of monthly calcined petroleum coke consumption (metric tons).

(e) Annual operating hours for each titanium dioxide process line.

§ 98.318 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart FF—Underground Coal Mines

§ 98.320 Definition of the source category.

(a) This source category consists of active underground coal mines and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to a subsurface coal seam, where the coal is then mined with equipment such as cutting machines, and transported to the surface. Active underground coal mines are mines categorized by MSHA as active and where coal is currently being produced or has been produced within the previous 90 days.

(b) This source category comprises the following emission points:

(1) Each ventilation well or shaft.

(2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area.

(c) This source category does not include abandoned (closed) mines, surface coal mines, or post-coal mining activities.

§ 98.321 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a underground coal mining process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.322 GHGs to report.

You must report the following:

(a) CH_4 emissions from each ventilation well or shaft and each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(b) CO_2 emissions from coal mine gas CH_4 destruction, where the gas is not a fuel input for energy generation or use.

(c) CO_2, CH_4, and N_2O emissions from stationary fuel combustion devices. You must follow the requirements of subpart C of this part.

§ 98.323 Calculating GHG emissions.

(a) For each ventilation well or shaft, you must estimate the quarterly CH_4 liberated from the mine ventilation system using the measured CH_4 content and flow rate, and Equation FF–1 of this section. You must measure CH_4 content, flow rate, temperature, and pressure of the gas using the procedures outlined in § 98.324.

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

Where:

CH_{4V} = Quarterly CH_4 liberated from ventilation systems (metric tons CH_4).

V = Measured volumetric flow rate of active ventilation of mining operations (cfm).

C = Measured CH_4 concentration of ventilation gas during active ventilation of mining operations (%, wet basis).

n = The number of days in the quarter where active ventilation of mining operations is taking place.

0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).

T = Temperature at which flow is measured (°R).

P = Pressure at which flow is measured (atm).

1,440 = Conversion factor (min/day).

0.454/1,000 = Conversion factor (metric ton/lb).

(b) For each degasification system, you must estimate the quarterly CH_4 liberated from the mine degasification system using measured CH_4 content, flow rate, temperature, and pressure, and Equation FF–2 of this section.

$$CH_{4D} = n \star \left(V \star \frac{C}{100\%} \star 0.0423 \star \frac{520^{o}R}{T} \star \frac{P}{1\ atm} \star 1,440 \star \frac{0.454}{1,000} \right) \qquad \text{(Eq. FF-2)}$$

Where:

CH_{4D} = Quarterly CH_4 liberated from the degasification system (metric tons CH_4).

V = Measured average volumetric flow rate for the days in the quarter when the degasification system is in operation and the continuous monitoring equipment is properly functioning (cfm).

C = Estimated or measured average CH_4 concentration of gas for the days in the quarter when the degasification system is in operation and the continuous monitoring equipment is properly functioning (%, wet basis).

n = The number of days in the quarter.

0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).

T = Measured average temperature at which flow is measured (°R).

P = Measured average pressure at which flow is measured (atm).

1,440 = Conversion factor (min/day).

0.454/1,000 = Conversion factor (metric ton/lb).

(c) If gas from degasification system wells or ventilation shafts is destroyed you must calculate the quarterly CH_4 destroyed using Equation FF–3 of this section. You must measure CH_4 content and flowrate according to the provisions in § 98.324.

$$CH_4 \text{ destroyed} = CH_4 \text{ x } DE/100 \qquad \text{(Eq. FF-3)}$$

Where:

CH_4 destroyed = Quantity of CH_4 liberated from mine that is destroyed (metric tons).

CH_4 = Amount of CH_4 collected for destruction(metric tons).

DE = Destruction efficiency of the destruction equipment, based on the lesser of the manufacturer's specified destruction efficiency or 98 percent (%)'.

(d) You must calculate the quarterly net CH_4 emissions to the atmosphere using Equation FF–3 of this section.

$$CH_4 \text{ emitted (net)} = CH_{4V} + CH_{4D} - CH_4 \text{ destroyed} \qquad \text{(Eq. FF-4)}$$

Where:

CH_4 emitted (net) = Quarterly CH_4 emissions from mine ventilation and degasification systems (metric tons).

CH_{4V} = Quarterly CH_4 liberated from mine ventilation systems, calculated using Equation FF–1 of this section (metric tons).

CH_{4D} = Quarterly CH_4 liberated from mine degasification systems, calculated using Equation FF–2 of this section (metric tons).

CH_4 destroyed = Quarterly CH_4 destroyed, calculated using Equation FF–3 of this section (metric tons).

(e) For each degasification or ventilation system with on-site coal mine gas CH_4 destruction, where the gas is not a fuel input for energy generation or use, you must estimate the CO_2 emissions using Equation FF–5 of this section. You must measure the CH_4 content and the flow rate according to the provisions in § 98.324.

$$CO_2 = CH_{4o} \star 44/16 \qquad \text{(Eq. FF-5)}$$

Where:

CO_2 = Quarterly CO_2 emissions from CH_4 destruction (metric tons).

CH_{4o} = CH_4 destroyed, calculated using Equation FF–3 of this section (metric tons).

DE = Destruction efficiency, based on the lesser of the manufacturer's specified destruction efficiency or 98 percent (%).

44/16 = Ratio of molecular weights of CO_2 to CH_4.

§ 98.324 Monitoring and QA/QC requirements.

(a) The flow and CH_4 content of coal mine gas destroyed must be determined using ASTM D1945–03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(b) For liberation of methane from ventilation systems, you must do one of the following:

(1) Monitor emissions from each well or shaft where active ventilation is taking place by collecting quarterly grab samples and making quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same location as MSHA inspection samples are taken. You must follow MSHA sampling procedures as set forth in the MSHA Handbook entitled, General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number: PH–08–V–1, January 1, 2008. You must record the airflow, temperature, and pressure measured, the hand-held methane and oxygen readings in percentile, the bottle number of samples collected, and the location of the measurement or collection.

(2) Obtain results of the quarterly testing performed by MSHA.

(c) For liberation of methane at degasification systems, you must monitor methane concentrations and flow rate from each degasification well or shaft using any of the oil and gas flow meter test methods incorporated by reference in § 98.7.

(d) All fuel flow meters and gas composition monitors monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, MSHA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer or other applicable standards.

(e) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(f) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters, and other measurement devices. The estimated accuracy of measurements, and the technical basis for the estimated accuracy shall be recorded.

§ 98.325 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with paragraph (b) of this section.

(b) For each missing value of CH_4 concentration, flow rate, temperature, and pressure for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ 98.326 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each mine:

(a) Quarterly volumetric flow rate measurement results for all ventilation systems, including date and location of measurement.

(b) Quarterly CH_4 concentration measurement results for all ventilation systems, including date and location of measurement.

(c) Quarterly CEMS volumetric flow data used to calculate CH_4 liberated from degasification systems (summed from daily data).

(d) Quarterly CEMS CH_4 concentration data used to calculate CH_4 liberated from degasification systems (average from daily data).

(e) Quarterly CH_4 destruction at ventilation and degasification systems.

(f) Dates in reporting period where active ventilation of mining operations is taking place.

(g) Dates in reporting period when continuous monitoring equipment is not properly functioning.

(h) Quarterly averages of temperatures and pressures at the time and at the conditions for which all measurements are made.

(i) Quarterly CH_4 liberated from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(j) Quarterly CH_4 emissions (net) from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(k) Quarterly CO_2 emissions from on-site destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use.

§ 98.327 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Calibration records for all monitoring equipment.

(b) Records of gas sales.

(c) Logbooks of parameter measurements.

(d) Laboratory analyses of samples.

§ 98.328 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart GG—Zinc Production

§ 98.330 Definition of the source category.

The zinc production source category consists of zinc smelters and secondary zinc recycling facilities.

§ 98.331 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a zinc production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.332 GHGs to report.

(a) You must report the CO_2 process emissions from each Waelz kiln and electrothermic furnace used for zinc production, as applicable to your facility.

(a) You must report the CO_2, CH_4, and N_2O emissions from each stationary combustion unit, following requirements of subpart C of this part.

§ 98.333 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must estimate total CO_2 emissions according to the requirements in § 98.33(a).

(b) If you do not operate and maintain a CEMS that measures total CO_2 emissions consistent with the requirements in subpart C of this part, you must determine the total CO_2 emissions from the Waelz kilns or electrothermic furnaces at your facility used for zinc production using the procedures specified in paragraphs (b)(1) and (2) of this section.

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each calendar month and estimate total annual CO_2 process emissions from each affected unit at your facility using Equation GG–1. For electrothermic furnaces, carbon containing input materials include carbon eletrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents.

$$E_{CO_2} = \sum_{n=1}^{12} \frac{44}{12} * \left[(Zinc)_n * (C_{Zinc})_n + (Flux)_n * (C_{Flux})_n + (Electrode)_n * (C_{Electrode})_n + (Carbon)_n * (C_c) \right] \qquad \text{(Eq. GG-1)}$$

Where:

E_{CO_2} = Total CO_2 process emissions from an individual Waelz kiln or electrothermic furnace (metric tons per year).

44/12 = Ratio of molecular weights, CO_2 to carbon.

$(Zinc)_n$ = Mass of zinc bearing material charged to the furnace in month ''n'' (metric tons).

$(C_{Zinc})_n$ = Carbon content of the zinc bearing material, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Flux)_n$ = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month ''n'' (metric tons).

$(C_{Flux})_n$ = Average carbon content of the flux materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

$(Electrode)_n$ = Mass of carbon electrode consumed in month ''n'', for electrothermic furnace (metric tons).

$(C_{Electrode})_n$ = Average carbon content of the carbon electrode, from the carbon analysis results for month ''n'', for electrothermic furnace (percent by weight, expressed as a decimal fraction).

$(Carbon)_n$ = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month ''n'' (metric tons).

$(C_{Carbon})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month ''n'' (percent by weight, expressed as a decimal fraction).

(2) You must determine the total CO_2 emissions from the Waelz kilns or electrothermic furnaces at your facility using Equation GG–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. GG-2)}$$

Where:

CO_2 = Total annual CO_2 emissions, metric tons/year.

E_{CO2k} = Annual CO_2 emissions from Waelz kiln or electrothermic furnace k calculated using Equation GG–1 of this section, metric tons/year.

k = Total number of Waelz kilns or electrothermic furnaces at facility used for the zinc production.

§ 98.334 Monitoring and QA/QC requirements.

If you determine CO_2 emissions using the carbon input procedure in § 98.333(b)(1), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing input material by direct measurement of the quantity of the material placed in the unit or by calculations using process operating information, and record the total mass for the material for each calendar month.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material for each calendar month using information provided by your material supplier or by collecting and analyzing a representative sample of the material using an analysis method appropriate for the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory each calendar month using the test methods (and their QA/QC procedures) in § 98.7. Use ASTM E1941–04 (''Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys'') for analysis of zinc bearing materials; ASTM D5373–02 (''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'') for analysis of carbonaceous reducing agents and carbon electrodes, and ASTM C25–06 (''Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime'') for analysis of flux materials such as limestone or dolomite.

§ 98.335 Procedures for estimating missing data.

For the carbon input procedure in § 98.333(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations.

(a) For each missing value of the carbon content the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing records of the mass of carbon-containing input material consumption, the substitute data value shall be the best available estimate of the mass of the input material. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.336 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section for each Waelz kiln or electrothermic furnace.

(a) Annual CO_2 emissions in metric tons, and the method used to estimate emissions.

(b) Annual zinc product production capacity (in metric tons).

(c) Total number of Waelz kilns and electrothermic furnaces at the facility.

(d) Number of facility operating hours in calendar year.

(e) If you use the carbon input procedure, report for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (e)(1) and (2) of this section.

(1) Annual material quantity (in metric tons).

(2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.337 Records that must be retained.

In addition to the records required by § 98.3(g) of subpart A of this part, you must retain the records specified in paragraphs (a) through (d) of this section.

(a) Monthly facility production quantity for each zinc product (in metric tons).

(b) Number of facility operating hours each month.

(c) Annual production Quantity for each zinc product (in metric tons).

(d) If you use the carbon input procedure, record for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (d)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(e) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each Waelz kiln or electrothermic furnace, as applicable to your facility. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.338 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart HH—Landfills

§ 98.340 Definition of the source category.

(a) This source category consists of the following sources at municipal solid waste (MSW) landfill facilities: landfills, landfill gas collection systems, and landfill gas combustion systems (including flares). This source category also includes industrial landfills (including, but not limited to landfills located at food processing, pulp and paper, and ethanol production facilities).

(b) This source category does not include hazardous waste landfills and construction and demolition landfills.

§ 98.341 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a landfill process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.342 GHGs to report.

(a) You must report CH_4 generation and CH_4 emissions from landfills.

(b) You must report CH_4 destruction resulting from landfill gas collection and combustion systems.

(c) You must report CO_2, CH_4, and N_2O emissions from stationary fuel combustion devices. This includes emissions from the combustion of fuels used in flares (e.g., for pilot gas or to supplement the heating value of the landfill gas). Follow the requirements of subpart C of this part. Do not calculate CO_2 emissions resulting from the flaring of landfill gas.

§ 98.343 Calculating GHG emissions.

(a) For all landfills subject to the reporting requirements of this subpart, calculate annual modeled CH_4 generation according to the applicable requirements in paragraphs (a)(1) through (4) of this section.

(1) Calculate annual modeled CH_4 generation using recorded or estimated waste disposal quantities, default values from Table HH–1, and Equation HH–1 of this section.

$$G_{CH4} = \left[\sum_{x=S}^{T-1}\left\{W_x L_{0,x}\left(e^{-k(T-x-1)} - e^{-k(T-x)}\right)\right\}\right] \qquad \text{(Eq. HH-1)}$$

Where:

G_{CH4} = Modeled methane generation rate in reporting year T (metric tons CH_4).
X = Year in which waste was disposed.
S = Start year of calculation. Use the year 50 years prior to the year of the emissions estimate, or the opening year of the landfill, whichever is more recent.
T = Reporting year for which emissions are calculated.
Wx = Quantity of waste disposed in the landfill in year X from tipping fee receipts or other company records (metric tons, as received (wet weight)).
L_0 = CH_4 generation potential (metric tons CH_4/metric ton waste) = MCF*DOC*DOCF*F*16/12.
MCF = Methane correction factor (fraction).
DOC = Degradable organic carbon [fraction (metric tons C/metric ton waste)].
DOC_F = Fraction of DOC dissimilated (fraction).
F = Fraction by volume of CH_4 in landfill gas.
k = Rate constant (yr-1).

(2) For years when material-specific waste quantity data are available, and for industrial waste landfills, apply Equation HH–1 of this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in Table HH–1. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. For both MSW and industrial landfills, you may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and L_0 in Table HH–1 of this subpart for the total quantity of waste disposed in those years.

(3) For years prior to reporting for which waste disposal quantities are not readily available for MSW landfills, W_x shall be estimated using the estimated population served by the landfill in each year, the values for national average per capita waste disposal and fraction of generated waste disposed of in solid waste disposal sites found in Table HH–2 of this subpart.

(4) For industrial landfills, W_x in reporting years must be determined by direct mass measurement of waste entering the landfill using industrial scales with a manufacturer's stated accuracy of ±2 percent. For previous years, where data are unavailable on waste disposal quantities, estimate the waste quantities according to the requirements in paragraphs (a)(4)(i) and (ii) of this section.

(i) Calculate the average waste disposal rate per unit of production for the first applicable reporting year using Equation HH–2 of this section.

$$WDF = \left[\sum_{n=1}^{N}\left\{\frac{W_n}{N * P_n}\right\}\right] \qquad \text{(Eq. HH-2)}$$

Where:

WDF = Average waste disposal factor determined on the first year of reporting (metric tons per production unit). The average waste disposal factor should not be re-calculated in subsequent reporting years.
N = Number of years for which disposal and production data are available.
W_n = Quantity of waste placed in the industrial landfill in year n (metric tons).
P_n = Quantity of product produced in year n (production units).

(ii) Calculate the waste disposal quantities for historic years in which direct waste disposal measurements are not available using historical production data and Equation HH–3 of this section.

$$W_x = WDF * P_x \qquad \text{(Eq. HH-3)}$$

Where:

X = Historic year in which waste was disposed.
W_x = Projected quantity of waste placed in the landfill in year X (metric tons).
WDF = Average waste disposal factor from Equation HH–1 of this section (metric tons per production unit).
P_x = Production quantity for the facility in year X from company records (production units).

(b) For landfills with gas collection systems, calculate the quantity of CH_4 destroyed according to the requirements in paragraphs (b)(1) through (4) of this section.

(1) Measure continuously the flow rate, CH_4 concentration, temperature, and pressure, of the collected landfill gas (before any treatment equipment) using a monitoring meter specifically for CH_4 gas, as specified in § 98.344.

(2) Calculate the quantity of CH_4 recovered for destruction using Equation HH–4 of this section.

$$R = \sum_{n=1}^{365}\left(V_n * \frac{C_n}{100\%} * 0.0423 * \frac{520^oR}{T_n} * \frac{P_n}{1\ \text{atm}} * 1,440 * \frac{0.454}{1,000}\right) \qquad \text{(Eq. HH-4)}$$

Where:

R = Annual quantity of recovered CH_4 (metric tons CH_4).
V_n = Daily average volumetric flow rate for day n (acfm).
C_n = Daily average CH_4 concentration of landfill gas for day n (%, wet basis).
0.0423 = Density of CH_4 lb/scf (at 520°R or 60°F and 1 atm).
T_n = Temperature at which flow is measured for day n (°R).
P_n = Pressure at which flow is measured for day n (atm).
1,440 = Conversion factor (min/day).
0.454/1,000 = Conversion factor (metric ton/lb).

(c) Calculate CH_4 generation (adjusted for oxidation in cover materials) and actual CH_4 emissions (taking into account any CH_4 recovery, and oxidation in cover materials) according to the applicable methods in paragraphs (d)(1) through (4) of this section.

(1) Calculate CH_4 generation, adjusted for oxidation, from the modeled CH_4 (GCH_4 from Equation HH–1) using Equation HH–5 of this section.

$$MG = G_{CH4} \star (1 - OX) \qquad \text{(Eq. HH-5)}$$

Where:

MG = Methane generation from the landfill in the reporting year, adjusted for oxidation (metric tons CH_4).
G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section (metric tons CH_4).
OX = Oxidation fraction default rate is 0.1 (10%).

(2) For landfills that do not have landfill gas collection systems, the CH_4 emissions are equal to the CH_4 generation calculated in Equation HH–5 of this section.

(3) For landfills with landfill gas collection systems, calculate CH_4 emissions using the methodologies specified in paragraphs (c)(3)(i) and (ii) of this section.

(i) Calculate CH_4 emissions from the modeled CH_4 generation and measured CH_4 recovery using Equation HH–6 of this section.

$$\text{Emissions} = \left[\left(G_{CH4} - R\right) * \left(1 - OX\right) + R \star \left(1 - DE\right)\right] \qquad \text{(Eq. HH-6)}$$

Where:

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).
G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section or the quantity of recovered CH_4 from Equation HH–4 of this section, whichever is greater (metric tons CH_4).
R = Quantity of recovered CH_4 from Equation HH–4 of this section (metric tons).
OX = Oxidation fraction default rate is 0.1 (10%).
DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99)

(ii) Calculate CH_4 generation and CH_4 emissions using measured CH_4 recovery and estimated gas collection efficiency and Equations HH–7 and HH–8, of this section.

$$MG = \frac{R}{CE} \star (1 - OX) \qquad \text{(Eq. HH-7)}$$

$$\text{Emissions} = \left[\left(\frac{R}{CE_{CH4}} - R\right) * \left(1 - OX\right) + R \star \left(1 - DE\right)\right] \qquad \text{(Eq. HH-8)}$$

Where:

MG = Methane generation from the landfill in the reporting year (metric tons CH_4).
Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).
R = Quantity of recovered CH_4 from Equation HH–4 of this section (metric tons CH_4).
CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials. (Default is 0.75).
OX = Oxidation fraction (default rate is 0.1 (10%)).
DE = Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99).

§ 98.344 Monitoring and QA/QC requirements.

(a) The quantity of waste landfilled must be determined using mass measurement equipment meeting the requirements for commercial weighing equipment as described in ''Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices'' NIST Handbook 44, 2008.

(b) The quantity of landfill gas CH_4 destroyed must be determined using ASTM D1945–03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(c) All fuel flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using ASTM D1945–03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§ 98.345 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraphs (a) through (c) of this section.

(a) For each missing value of the CH_4 content, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing gas flow rates, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing daily waste disposal data for disposal in reporting years, the substitute value shall be the average daily waste disposal quantity for that day of the week as measured on the week before and week after the missing daily data.

§ 98.346 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each landfill.

(a) Waste disposal for each year of landfilling.

(b) Method for estimating waste disposal.

(c) Waste composition, if available, in percentage categorized as—

(1) Municipal,

(2) Construction and demolition,

(3) Biosolids or biological sludges,

(4) Industrial, inorganic,

(5) Industrial, organic,

(6) Other, or more refined categories, such as those for which k rates are available in Table HH–1 of this subpart.

(d) Method for estimating waste composition.

(e) Fraction of CH_4 in landfill gas based on measured values if the landfill has a gas collection system or a default.

(f) Oxidation fraction used in the calculations.

(g) Degradable organic carbon (DOC) used in the calculations.

(h) Decay rate k used in the calculations.

(i) Fraction of DOC dissimilated used in the calculations.

(j) Methane correction factor used in the calculations.

(k) Annual methane generation and methane emissions (metric tons/year) according to the methodologies in § 98.343(c)(1) through (3). Landfills with gas collection system must separately report methane generation and emissions according to the methodologies in § 98.343(c)(3)(i) and (ii) and indicate which values are calculated using the methodologies in § 98.343(c)(ii).

(l) Landfill design capacity.

(m) Estimated year of landfill closure.

(n) Total volumetric flow of landfill gas for landfills with gas collection systems.

(o) CH_4 concentration of landfill gas for landfills with gas collection systems.

(p) Monthly average temperature at which flow is measured for landfills with gas collection systems.

(q) Monthly average pressure at which flow is measured for landfills with gas collection systems.

(r) Destruction efficiency used for landfills with gas collection systems.

(s) Methane destruction for landfills with gas collection systems (total annual, metric tons/year).

(t) Estimated gas collection system efficiency for landfills with gas collection systems.

(u) Methodology for estimating gas collection system efficiency for landfills with gas collection systems.

(v) Cover system description.

(w) Number of wells in gas collection system.

(x) Acreage and quantity of waste covered by intermediate cap.

(y) Acreage and quantity of waste covered by final cap.

(z) Total CH_4 generation from landfills.

(aa) Total CH_4 emissions from landfills.

§ 98.347 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment.

§ 98.348 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE HH–1 OF SUBPART HH—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS

Factor	Default value	Units
Waste model—bulk waste option		
k (precipitation <20 inches/year)	0.02	yr^{-1}
k (precipitation 20–40 inches/year)	0.038	yr^{-1}
k (precipitation >40 inches/year)	0.057	yr^{-1}
L_0 (Equivalent to DOC = 0.2028 when MCF=1, DOC_F=0.5, and F=0.5).	0.067	metric tons CH_4/ metric ton waste.
Waste model—All MSW and industrial waste landfills		
MCF	1	
DOC_F	0.5	
F	0.5	

TABLE HH–1 OF SUBPART HH—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

Factor	Default value	Units
Waste model—MSW using waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis.
DOC (garden)	0.2	Weight fraction, wet basis.
DOC (paper)	0.4	Weight fraction, wet basis.
DOC (wood and straw)	0.43	Weight fraction, wet basis.
DOC (textiles)	0.24	Weight fraction, wet basis.
DOC (diapers)	0.24	Weight fraction, wet basis.
DOC (sewage sludge)	0.05	Weight fraction, wet basis.
DOC (bulk waste)	0.20	Weight fraction, wet basis.
k (food waste)	0.06 to 0.185 [a]	yr^{-1}
k (garden)	0.05 to 0.10 [a]	yr^{-1}
k (paper)	0.04 to 0.06 [a]	yr^{-1}
k (wood and straw)	0.02 to 0.03 [a]	yr^{-1}
k (textiles)	0.04 to 0.06 [a]	yr^{-1}
k (diapers)	0.05 to 0.10 [a]	yr^{-1}
k (sewage sludge)	0.06 to 0.185 [a]	yr^{-1}
Waste model—Industrial waste landfills		
DOC (food processing)	0.15	Weight fraction, wet basis.
DOC (pulp and paper)	0.2	Weight fraction, wet basis.
k (food processing)	0.185	yr^{-1}
k (pulp and paper)	0.06	yr^{-1}
Calculating methane generation and emissions		
OX	0.1.	
DE	0.99.	

[a] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate and the greater value when it does not.

TABLE HH–2 OF SUBPART HH—U.S. PER CAPITA WASTE DISPOSAL RATES

Year	Waste per capita ton/cap/yr	% to SWDS
1940	0.64	100
1941	0.64	100
1942	0.64	100
1943	0.64	100
1944	0.63	100
1945	0.64	100
1946	0.64	100
1947	0.63	100
1948	0.63	100
1949	0.63	100
1950	0.63	100
1951	0.63	100
1952	0.63	100
1953	0.63	100
1954	0.63	100
1955	0.63	100
1956	0.63	100
1957	0.63	100
1958	0.63	100
1959	0.63	100
1960	0.63	100
1961	0.64	100
1962	0.64	100
1963	0.65	100
1964	0.65	100
1965	0.66	100
1966	0.66	100
1967	0.67	100
1968	0.68	100
1969	0.68	100
1970	0.69	100
1971	0.69	100
1972	0.70	100
1973	0.71	100

TABLE HH–2 OF SUBPART HH—U.S. PER CAPITA WASTE DISPOSAL RATES—Continued

Year	Waste per capita ton/cap/yr	% to SWDS
1974	0.71	100
1975	0.72	100
1976	0.73	100
1977	0.73	100
1978	0.74	100
1979	0.75	100
1980	0.75	100
1981	0.76	100
1982	0.77	100
1983	0.77	100
1984	0.78	100
1985	0.79	100
1986	0.79	100
1987	0.80	100
1988	0.80	100
1989	0.85	84
1990	0.84	77
1991	0.78	76
1992	0.76	72
1993	0.78	71
1994	0.77	67
1995	0.72	63
1996	0.71	62
1997	0.72	61
1998	0.78	61
1999	0.78	60
2000	0.84	61
2001	0.95	63
2002	1.06	66
2003	1.06	65
2004	1.06	64
2005	1.06	64
2006	1.06	64

Subpart II—Wastewater Treatment

§ 98.350 Definition of source category.

(a) A wastewater treatment system is the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from waters released from industrial processes. This source category applies to on-site wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities.

(b) This source category does not include centralized domestic wastewater treatment plants.

§ 98.351 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a wastewater treatment process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.352 GHGs to report.

(a) You must report annual CH_4 emissions from anaerobic wastewater treatment processes.

(b) You must report annual CO_2 emissions from oil/water separators at petroleum refineries.

(c) You must report CO_2, CH_4, and N_2O emissions from the combustion of fuels in stationary combustion devices and fuels used in flares by following the requirements of subpart C of this part. For flares, calculate the CO_2 emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in subpart C of this part. Do not include CO_2 emissions resulting from the combustion of anaerobic digester gas.

§ 98.353 Calculating GHG emissions.

(a) Estimate the annual CH_4 mass emissions from systems other than digesters using Equation II–1 of this section. The value of flow and COD must be determined in accordance with the monitoring requirements specified in § 98.354. The flow and COD should reflect the wastewater treated anaerobically on site in anaerobic systems such as lagoons.

$$CH_4 = \sum_{n=1}^{12}\left[\text{Flow}_n * \text{COD} * B_o * \text{MCF} * 0.001\right] \qquad \text{(Eq. II-1)}$$

Where:

CH_4 = Annual CH_4 mass emissions from the wastewater treatment system (metric tons).

Flow_n = Volumetric flow rate of wastewater sent to an anaerobic treatment system in month n (m^3/month).

COD = Average monthly value for chemical oxygen demand of wastewater entering anaerobic treatment systems other than digesters (kg/m^3).

B_0 = Maximum CH_4 producing potential of wastewater (kg CH_4/kg COD), default is 0.25.

MCF = CH_4 conversion factor, based on relevant values in Table II–1.
0.001 = Conversion factor from kg to metric tons.

(b) For each petroleum refining facility having an on-site oil/water separator, estimate the annual CO_2 mass emissions using Equation II–2 using measured values for the volume of wastewater treated, and default values for emission factors by separator type from Table II–1 of this subpart. The flow should reflect the wastewater treated in the oil/water separator.

$$CO_2 = \sum_{n=1}^{12}\left[EF_{sep} * V_{H_2O} * C * \frac{44}{12} * 0.001 \text{ metric tons } CH_4/kg\right] \qquad \text{(Eq. II-2)}$$

Where:
CO_2 = Annual emissions of CO_2 from oil/water separators (metric tons/yr).
EF_{sep} = Emissions factor for the type of separator (kg NMVOC/m^3 wastewater treated).
V_{H20} = Volumetric flow rate of wastewater treated through oil/water separator in month m (m^3/month).
C = Carbon fraction in NMVOC (default = 0.6).
44/12 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor from kg to metric tons.

(c) For each anaerobic digester, estimate the annual mass of CH_4 destroyed using Equations II–3 and II–4 of this section.

$$CH_4d = CH_4AD * DE \qquad \text{(Eq. II-3)}$$

Where:
CH_4d = Annual quantity of CH_4 destroyed (kg/yr).
CH_4AD = Annual quantity of CH_4 generated by anaerobic digester, as calculated in Equation II–4 of this section (metric tons CH_4).
DE = CH_4 destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99).

$$CH_4AD = \sum_{n=1}^{365}\left[V_n \star \frac{C_n}{100\%} \star 0.0423 \star \frac{520\ \ R}{T_n} \star \frac{P_n}{1 \text{ atm}} \star 1{,}440 \text{ minutes/day} \star \frac{0.454 \text{ metric ton}}{1{,}000 \text{ pounds}}\right] \qquad \text{(Eq. II-4)}$$

Where:
CH_4AD = Annual quantity of CH_4 generated by anaerobic digestion (metric tons CH_4/yr).
V_n = Daily average volumetric flow rate for day n, as determined from daily monitoring specified in § 98.354 (acfm).
C_n = Daily average CH_4 concentration of digester gas for day n, as determined from daily monitoring specified in § 98.354 (%, wet basis).
0.0423 = Density of CH_4 lb/scf (at 520 °R or 60 °F and 1 atm).
T_n = Temperature at which flow is measured for day n (°R).
P_n = Pressure at which flow is measured for day n (atm).

§ 98.354 Monitoring and QA/QC requirements.

(a) The quantity of COD treated anaerobically must be determined using analytical methods for industrial wastewater pollutants and must be conducted in accordance with the methods specified in 40 CFR part 136.

(b) All flow meters must be calibrated using the procedures and frequencies specified by the device manufacturer.

(c) For anaerobic treatment systems, facilities must monitor the wastewater flow and COD no less than once per week. The sample location must represent the influent to anaerobic treatment for the time period that is monitored. The flow sample must correspond to the location used to measure the COD. Facilities must collect 24-hour flow-weighted composite samples, unless they can demonstrate that the COD concentration and wastewater flow into the anaerobic treatment system does not vary. In this case, facilities must collect 24-hour time-weighted composites to characterize changes in wastewater due to production fluctuations, or a grab sample if the influent flow is equalized resulting in little variability.

(d) For oil/water separators, facilities must monitor the flow no less than once per week. The sample location must represent the influent to oil/water separator for the time period that is monitored.

(e) The quantity of gas destroyed must be determined using any of the oil and gas flow meter test methods incorporated by reference in § 98.7.

(f) All gas flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (*e.g.*, ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Gas flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(g) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the device manufacturer.

(h) All equipment (temperature and pressure monitors and gas flow meters and gas composition monitors) shall be maintained as specified by the manufacturer.

(i) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§ 98.355 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (*e.g.*, if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements in paragraphs (a) and (b) of this section:

(a) For each missing monthly value of COD or wastewater flow treated, the substitute data value shall be the arithmetic average of the quality-assured values of those parameters for the weeks immediately preceding and immediately following the missing data incident. For each missing value of the CH_4 content or gas flow rates, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident.

(b) If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ 98.356 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for the wastewater treatment system.

(a) Type of wastewater treatment system.

(b) Percent of wastewater treated at each system component.

(c) COD.

(d) Influent flow rate.

(e) B_0.

(f) MCF.

(g) Methane emissions.

(h) Type of oil/water separator (petroleum refineries).

(i) Emissions factor for the type of separator (petroleum refineries).

(j) Carbon fraction in NMVOC (petroleum refineries).

(k) CO_2 emissions (petroleum refineries).

(l) Total volumetric flow of digester gas (facilities with anaerobic digesters).

(m) CH_4 concentration of digester gas (facilities with anaerobic digesters).

(n) Temperature at which flow is measured (facilities with anaerobic digesters).

(o) Pressure at which flow is measured (facilities with anaerobic digesters).

(p) Destruction efficiency used (facilities with anaerobic digesters).

(q) Methane destruction (facilities with anaerobic digesters).

(r) Fugitive methane (facilities with anaerobic digesters).

§ 98.357 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment.

§ 98.358 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE II–1 OF SUBPART II—EMISSION FACTORS

Factors	Default value	Units
B_0	0.25	Kg CH_4/kg COD.
MCF—anaerobic deep lagoon, anaerobic reactor (e.g., upflow anaerobic sludge blanket, fixed film).	0.8	Fraction.
MCF—anaerobic shallow lagoon (less than 2 m)	0.2	Fraction.
MCF—centralized aerobic treatment system, well managed	0	Fraction.
MCF—Centralized aerobic treatment system, not well managed (overloaded).	0.3	Fraction.
Anaerobic digester for sludge	0.8	Fraction.
C fraction in NMOC	0.6	Fraction.
EF sep—Gravity Type (Uncovered)	1.11E–01	Kg NMVOC/m^3 wastewater
EF sep—Gravity Type (Covered)	3.30E–03	Kg NMVOC/m^3 wastewater.
EF sep—Gravity Type—(Covered and Connected to a Destruction Device).	0	Kg NMVOC/m^3 wastewater.
DAF or IAF—uncovered	4.00E–34	Kg NMVOC/m^3 wastewater.
DAF or IAF—covered	1.20E–44	Kg NMVOC/m^3 wastewater.
DAF or IAF—covered and connected to a destruction device	0	Kg NMVOC/m^3 wastewater.

DAF = dissolved air flotation type.
IAF = induced air flotation type.

Subpart JJ—Manure Management

§ 98.360 Definition of the source category.

(a) This source category consists of manure management systems for livestock manure.

(b) A manure management system is as a system that stabilizes or stores livestock manure in one or more of the following system components: uncovered anaerobic lagoons, liquid/slurry systems, storage pits, digesters, drylots, solid manure storage, feedlots and other dry lots, high rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, and manure composting. This definition of manure management system encompasses the treatment of wastewaters from manure.

(c) This source category does not include components at a livestock operation unrelated to the stabilization or storage of manure such as daily spread or pasture/range/paddock systems.

§ 98.361 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a manure management system and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.362 GHGs to report.

(a) You must report annual aggregate CH_4 and N_2O emissions for each of the following manure management system (MMS) components at the facility:

(1) Liquid/slurry systems such as tanks and ponds.

(2) Storage pits.

(3) Uncovered anaerobic lagoons used for stabilization or storage or both.

(4) Digesters, including covered anaerobic lagoons.

(5) Solid manure storage including feedlots and other dry lots, high rise houses for caged laying hens, broiler and turkey production on litter, and deep bedding systems for cattle and swine.

(6) Manure composting.

(b) You must report CO_2, CH_4, and N_2O emissions from the combustion of supplemental fuels used in flares by following the requirements of subpart C of this part. For flares, calculate the CO_2 emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in subpart C of this part. Do not include CO_2 emissions resulting from the combustion of digester gas in flares.

(c) A facility that is subject to this rule only because of emissions from manure management systems is not required to report emissions from fuels used in stationary combustion devices other than flares.

§ 98.363 Calculating GHG emissions.

(a) For manure management systems except digesters, estimate the annual CH_4 emissions using Equation JJ–1.

$$CH_4 \text{ Emissions (kg/yr)} = \sum_{\text{animal type}}\left[\sum_{\text{MMS}}\left[TVS \star VS_{MMS} \star 365.25 \text{ days/yr} \star B_0 \star MCF_{MMS}\right] \star 0.662 \text{ kg } CH_4/m^3\right] \quad \text{(Eq. JJ-1)}$$

Where:

TVS = Total volatile solids excreted by animal type, calculated using Equation JJ–2 of this section (kg/day).

VS_{MMS} = Percent of manure that is managed in each MMS (decimal) (assumed to be equivalent to the amount of VS in each system).

B_0 = Maximum CH_4-producing capacity, as specified in Table JJ–1 of this section (m^3 CH_4/kg VS).

MCF_{MMS} = CH_4 conversion factor for MMS, as specified in Table JJ–2 of this section (decimal).

$$TVS = \%TVS \star (\text{Population} \star TAM \star MER/1000) \qquad \text{(Eq. JJ-2)}$$

Where:

TVS = Total volatile solids excreted per animal type (kg/day).

%TVS = Annual average percent total volatile solids by animal type, as determined from monthly manure monitoring as specified in § 98.364 (decimal).

Population = Average annual animal population (head).

TAM = Typical animal mass, using either default values in Table JJ–1 of this section or farm-specific data (kg/head).

MER = Manure excretion rate, using either default values in Table JJ–1 of this section or farm-specific data (kg manure/day/1,000 kg animal mass).

(b) For each digester, estimate the annual CH_4 flow to the combustion device using Equation JJ–3 of this section, the amount of CH_4 destroyed using Eq JJ–4 of this section, and the amount of CH_4 leakage using Equation JJ–5 of this section.

$$CH_4D = \sum_{n=1}^{365}\left(V_n * \frac{C_n}{100\%} * 0.0423 * \frac{520^{\circ}R}{T_n} * \frac{P_n}{1 \text{ atm}} * 1,440 \text{ minutes/day} * \frac{0.454 \text{ metric ton}}{1,000 \text{ pounds}}\right) \qquad \text{(Eq. JJ-3)}$$

Where:

CH_4D = Methane flow to digester combustion device (metric tons CH_4/yr)

V_n = Daily average volumetric flow rate for day n, as determined from daily monitoring as specified in § 98.364 (acfm).

C_n = Daily average CH_4 concentration of digester gas for day n, as determined from daily monitoring as specified in § 98.364 (%, wet basis)

0.0423 = Density of CH_4 lb/scf (at 520 °R or 60 °F and 1 atm).

T_n = Temperature at which flow is measured for day n(°R).

P_n = Pressure at which flow is measured for day n (atm).

$$CH_4 \text{ Destruction at Digesters (kg/yr)} = CH_4D \star DE \star OH/Hours \qquad \text{(Eq. JJ-4)}$$

Where:

CH_4D = Annual quantity of CH_4 flow to digester combustion device, as calculated in Equation JJ–4 of this section (metric tons CH_4).

DE = CH_4 destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99).

OH = Number of hours combustion device is functioning in reporting year.

Hours = Hours in reporting year.

$$CH_4 \text{ Leakage at Digesters (kg/yr)} = CH_4D \times \left(\frac{1}{CE} - 1\right) \qquad \text{(Eq. JJ-5)}$$

CH_4D = Annual quantity of CH_4 combusted by digester, as calculated in Equation JJ–4 of this section (metric tons CH_4).

CE = CH_4 collection efficiency of anaerobic digester, as specified in Table JJ–3 of this section (decimal).

(c) For each manure management system type, estimate the annual N_2O emissions using Equation JJ–6 of this section.

$$\text{Direct } N_2O \text{ Emissions (kg/yr)} = \sum_{\text{animal type}}\left[\sum_{\text{MMS}} N_{ex} \text{ x } N_{ex,MMS} \text{ x } EF_{MMS} \text{ x } 365.25 \text{ days/yr}\right] \text{ x } 44 \; N_2O/28 \; N_2O\text{-}N \qquad \text{(Eq. JJ-6)}$$

Where:

N_{ex} = Total nitrogen excreted per animal type, calculated using Equation JJ–7 of this section (kg/day).

$N_{ex,MMS}$ = Percent of manure that is managed in each MMS (decimal) (assumed to be equivalent to the amount of N_{ex} in each system).

EF_{MMS} = Emission factor for MMS, as specified in Table JJ–4 of this section (kg N_2O–N/kg N).

$$N_{ex} = N_{Manure} \times (\text{Population} \times \text{TAM} \times \text{MER}/1000) \qquad \text{(Eq. JJ-7)}$$

Where:

N_{ex} = Total nitrogen excreted per animal type (kg/day).

N_{Manure} = Annual average percent of nitrogen present in manure by animal type, as determined from monthly manure monitoring, as specified in § 98.364 (decimal).

Population = Average annual animal population (head).

TAM = Typical animal mass, using either default values in Table JJ–1 of this section or farm-specific data (kg/head).

MER = Manure excretion rate, using either default values in Table JJ–1 of this section or farm-specific data (kg manure/day/1,000 kg animal mass).

(d) Estimate the annual total annual emissions using Equation JJ–8 of this section.

$$\begin{aligned}\text{Total Emissions (metric tons } CO_2e/\text{yr)} = {}&[(CH_4 \text{ emissions} + CH_4 \text{ flow to digester combustion device} - CH_4 \text{ destruction of digester} + CH_4 \text{ leakage of digester})\\ &\times 1 \text{ metric ton}/1000 \text{ kg} \times 21] + [\text{direct } N_2O \text{ emissions} \times 1 \text{ metric ton}/1000 \text{ kg} \times 310]\end{aligned} \qquad \text{(Eq. JJ-8)}$$

Where:

CH_4 emissions = From Equation JJ–1 of this section.

CH_4 flow to digester combustion device = From Equation JJ–3 of this section.

CH_4 destruction of digester = From Equation JJ–4 of this section.

CH_4 leakage of digester = From Equation JJ–5 of this section.

21 = Global Warming Potential of CH_4.

Direct N_2O emissions = from Equation JJ–6 of this section.

310 = Global Warming Potential of N_2O.

§ 98.364 Monitoring and QA/QC requirements.

(a) Perform a one-time analysis on your operation to determine the percent of total manure by weight that is managed in each on-site manure management system.

(b) Determine the annual average percent total volatile solids by animal type, (%TVS) by analysis of a representative sample using Method 160.4 (Residue, Volatile) as described in Methods for Chemical Analysis of Water and Wastes, EPA–600/4–79/020, Revised March 1983. The laboratory performing the analyses should be certified for analysis of waste for National Pollutant Discharge Elimination System compliance reporting. The sample analyzed should be a representative composite of freshly excreted manure from each animal type contributing to the manure management system. Total volatile solids of manure must be sampled and analyzed monthly.

(c) Determine the annual average percent of nitrogen present in manure by animal type (N_{Manure}) by analysis of a representative sample using Method 351.3 as described in Methods for Chemical Analysis of Water and Wastes, EPA–600/4–79–020, Revised March 1983. The laboratory performing the analyses should be certified for analysis of waste for National Pollutant Discharge Elimination System compliance reporting. The sample analyzed should be a representative composite of freshly excreted manure from each animal type contributing to the manure management system. Sample collection and analysis must be monthly.

(d) The flow and CH_4 concentration of gas from digesters must be determined using ASTM D1945–03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference in § 98.7).

(e) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(f) All gas flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (*e.g.*, ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Gas flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(g) All equipment (temperature and pressure monitors and gas flow meters and gas composition monitors) shall be maintained as specified by the manufacturer.

(h) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§ 98.365 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraph (b) of this section.

(b) For missing gas flow rates, volatile solids, or nitrogen or methane content data, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ 98.366 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each manure management system component:

(a) Type of manure management system component.

(b) Animal population (by animal type).

(c) Monthly total volatile solids content of excreted manure.

(d) Percent of manure handled in each manure management system component.

(e) B_0 value used.

(f) Methane conversion factor used.

(g) Average animal mass (for each type of animal).

(h) Monthly nitrogen content of excreted manure.

(i) N_2O emission factor selected.

(j) CH_4 emissions

(k) N_2O emissions.

(l) Total annual volumetric biogas flow (for systems with digesters).

(m) Average annual CH_4 concentration (for systems with digesters).

(n) Temperature at which gas flow is measured (for systems with digesters).

(o) Pressure at which gas flow is measured (for systems with digesters).

(p) Destruction efficiency used (for systems with digesters).

(q) Methane destruction (for systems with digesters).

(r) Methane generation from the digesters.

§ 98.367 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment.

§ 98.368 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE JJ–1 OF SUBPART JJ—WASTE CHARACTERISTICS DATA

Animal group	Animal group typical animal mass (kg)	Manure excretion rate (kg/day/1000 kg animal mass)	Maximum methane generation potential, B_o (m^3 CH_4/kg VS added)
Dairy Cows	604	80.34	0.24
Dairy Heifers	476	85	0.17
Feedlot Steers	420	51.2	0.33
Feedlot Heifers	420	51.2	0.33
Market Swine <60 lbs.	16	106	0.48
Market Swine 60–119 lbs.	41	63.4	0.48
Market Swine 120–179 lbs.	68	63.4	0.48
Market Swine >180 lbs.	91	63.4	0.48
Breeding Swine	198	31.8	0.48
Feedlot Sheep	25	40	0.36
Goats	64	41	0.17
Horses	450	51	0.33
Hens >/= 1 yr	1.8	60.5	0.39
Pullets	1.8	45.6	0.39
Other Chickens	1.8	60.5	0.39
Broilers	0.9	80	0.36
Turkeys	6.8	43.6	0.36

Table JJ-2 of Subpart JJ—Methane Conversion Factors

	MCFs by Temperature (degrees C)																		
	Cool					Temperate											Warm		
System	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Aerobic Treatment	0.0%					0.0%											0.0%		
Cattle Deep Litter (<1 month)	3.0%					3.0%											30.0%		
Cattle Deep Litter (>1 month)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Manure Composting - In Vessel	0.5%					0.5%											0.5%		
Manure Composting - Static Pile	0.5%					0.5%											0.5%		
Manure Composting-Extensive/ Passive	0.5%					1.0%											1.5%		
Manure Composting-Intensive	0.5%					1.0%											1.5%		
Solid storage	2.0%					4.0%											5.0%		
Poultry manure with litter	1.5%					1.5%											1.5%		
Poultry manure without litter	1.5%					1.5%											1.5%		
Dry lot	1.0%					1.5%											2.0%		
System	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Pit storage <1 month	3.0%					3.0%											30.0%		
Pit storage >1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Liquid/slurry (with crust cover)	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	34%	37%	41%	44%	48%	50%
Liquid/slurry (w/o crust cover)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Uncovered Anaerobic Lagoon	66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%

TABLE JJ–3 OF SUBPART JJ—COLLECTION EFFICIENCIES OF ANAEROBIC DIGESTERS

System type	Cover type	Methane collection efficiency
Covered anaerobic lagoon	Bank to bank, impermeable	0.975
(biogas capture)	Modular, impermeable	0.70
Complete mix, fixed film, or plug flow digester	Enclosed Vessel	0.99

TABLE JJ–4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N_2O-N/kg Kjdl N)

Waste management system	N_2O emission factor
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01
Digester	0
Uncovered Anaerobic Lagoon	0
Cattle Deep Bed (active mix)	0.07
Cattle Deep Bed (no mix)	0.01
Manure Composting (in vessel)	0.006
Manure Composting (intensive)	0.1
Manure Composting (passive)	0.01
Manure Composting (static)	0.006

TABLE JJ–4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N_2O-N/kg Kjdl N)—Continued

Waste management system	N_2O emission factor
Deep Pit	0.002
Dry Lot	0.02
Liquid/Slurry	0.005
Poultry with bedding	0.001
Poultry without bedding	0.001
Solid Storage	0.005

Subpart KK—Supplies of Coal

§ 98.370 Definition of the source category.

(a) This source category comprises coal mines, coal importers, coal exporters, and waste coal reclaimers.

(b) *Coal mine* means any active U.S. coal mine engaged in the production of coal within the U.S. during the calendar year regardless of the rank of coal produced, e.g., bituminous, sub-bituminous, lignite, anthracite. Any coal mine categorized as an active coal mine by MSHA is included.

(c) Coal importer has the same meaning given in § 98.6 and includes any U.S. coal mining company, wholesale coal dealer, retail coal dealer, or other organization that imports coal into the U.S. ‘‘Importer’’ includes the person primarily liable for the payment of any duties on the merchandise or an authorized agent acting on his or her behalf.

(d) Coal exporter has the same meaning given in § 98.6 and includes any U.S. coal mining company, wholesale coal dealer, retail coal dealer, or other organization that exports coal from the U.S.

(e) *Waste coal reclaimer* means any U.S. facility that reclaims or recovers waste coal from waste coal piles from previous mining operations and sells or delivers to an end-user.

§ 98.371 Reporting threshold.

Any supplier of coal who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.372 GHGs to report.

You must report the CO_2 emissions that would result from the complete combustion or oxidation of coal supplied during the calendar year.

§ 98.373 Calculating GHG emissions.

(a) For coal mines producing 100,000 short tons of coal or more annually, the estimate of CO_2 emissions shall be calculated using either Calculation Methodology 1 or Calculation Methodology 2 of this subpart.

(b) For coal mines producing less than 100,000 short tons of coal annually, and for coal exporters, coal importers, and waste coal reclaimers; CO_2 emissions shall be calculated using either Calculation Methodology 1, 2, or 3 of this subpart.

(c) For Calculation Methodology 1, 2, and 3 of this subpart, emissions of CO_2 shall be calculated using Equation KK–1 of this section. The difference between Calculation Methodology 1, 2, and 3 of this subpart, is the method for determining the carbon content in coal, as specified in paragraphs (d), (e), and (f) of this section:

$$CO_2 = 44/12 \star Mass \star Carbon \star 0.907 \qquad \text{(Eq. KK-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of coal (metric tons/yr).

44/12 = Ratio of molecular weights, CO_2 to carbon.

Mass = Quantity of coal produced from company records (short tons/yr).

Carbon = Annual weighted average fraction of carbon in the coal (decimal value).

0.907 = Conversion factor from short tons to metric tons.

(d) For coal mines using Calculation Methodology 1 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be based on daily measurements and calculated using Equation KK–2 of this section. For importers, exporters, and waste coal reclaimers using Methodology 1 of this subpart, measurements of each shipment can be used in place of daily measurements:

$$Carbon = \sum_{i=1}^{n} \left(x_i \; \star \; y_i \right) / S \qquad \text{(Eq. KK-2)}$$

Where:

Carbon = Annual mass fraction of coal carbon (dimensionless).

Xi = Daily or per shipment mass fraction of carbon in coal for day i measured by ultimate analysis (decimal value).

Yi = Amount of coal supplied on day i(short tons) as measured.

n = Number of operating days per year.

S = Total coal supplied during the year (short tons).

(e) For coal mines using Calculation Methodology 2 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be calculated on the basis of daily measurements of the gross calorific value (GCV) of the coal and a statistical relationship between carbon content and GCV (higher heating value). For importers, exporters, and waste coal reclaimers using Calculation Methodology 2 of this subpart, measurements of each shipment can be used in place of daily measurements.

(1) Equation KK–3 shall be used to determine the weighted annual average GCV of the coal, and the individual daily or per shipment values shall be determined according to the monitoring methodology for gross calorific values in § 98.374(f).

(2) The statistical relationship between GCV and carbon content shall be established according to the requirements in § 98.374(f).

(3) The estimated annual weighted average of the mass fraction of carbon in the coal shall be calculated by applying the slope coefficient, determined according to the requirements of § 98.374(f)(4), to the weighted annual average GCV of the coal determined according to Equation KK–3 of this section.

(f) For coal mines using Calculation Methodology 3 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be calculated on the basis of daily measurements of GCV of the coal and a default fraction of carbon in coal from Table KK–1 of this subpart. For importers, exporters, and waste coal reclaimers using Methodology 3 of this subpart, measurements of each shipment can be used in place of daily measurements.

(1) Equation KK–3 shall be used to determine the weighted annual average

GCV of the coal, and the individual daily or per shipment values shall be determined according to the monitoring methodology for gross calorific values in § 98.374(g).

(2) The estimated annual weighted average of the mass fraction of carbon in the coal shall be identified from Table KK–1 of this subpart using annual weighted GCV of the coal determined according to Equation KK–3 of this section.

(g) For Calculation Methodologies 2 and 3 of this subpart, the weighted annual average gross calorific value (GCV) or higher heating value of the coal shall be calculated using Equation KK–3 of this section:

$$GCV = \sum_{i=1}^{n} \left(z_i \ * \ y_i \right) / S \qquad \text{(Eq. KK-3)}$$

Where:

GCV = the weighted annual average gross calorific value or higher heating value of the coal (Btu/lb).

z_i = Daily or per shipment GCV or HHV of coal for day i measured by proximate analysis (decimal value).

y_i = Amount of coal supplied on day i (short tons) as measured.

n = Number of operating days per year.

S = Total coal supplied during the year (short tons).

§ 98.374 Monitoring and QA/QC requirements.

(a) The most current version of the NIST Handbook published by Weights and Measures Division, National Institute of Standards and Technology shall be used as the standard practice for all coal weighing.

(b) For all coal mines, the quantity of coal shall be determined as the total mass of coal in short tons sold and removed from the facility during the calendar year.

(c) For coal importers, the quantity of coal shall be determined as the total mass of coal in short tons imported into the U.S. during the calendar year, as reported to U.S. Customs.

(d) For coal exporters, the quantity of coal shall be determined as the total mass of coal in short tons sold and exported from the U.S., as reported to U.S. Customs.

(e) For waste coal reclaimers, the quantity of coal shall be determined as the total mass of coal in short tons sold for use as reported to state agencies.

(f) For reporters using Calculation Methodology 1 of this subpart, the carbon content shall be determined as follows:

(1) Representative coal samples shall be collected daily or per shipment using ASTM D4916–04, D6609–07, D6883–04, D7256/D7256M–06a, or D7430–08 from coal loaded on the conveyor belt.

(2) Daily or per shipment coal carbon content shall be determined using ASTM D5373 (Test Methods for Instrumental Determination of Carbon Hydrogen and Nitrogen in Laboratory Samples of Coal and Coke).

(g) For reporters using Calculation Methodology 2 of this subpart, the carbon content shall be determined as follows:

(1) Representative samples of coal shall be collected daily or per shipment using ASTM D4916–04, D6609–07, D6883–04, D7256/D7256M–06a, or D7430–08.

(2) Coal gross calorific value (GCV) shall be determined on the set of samples collected in paragraph (f)(1) of this section using ASTM D5865–07a, ''Standard Test Method for Gross Calorific Value of Coal and Coke to record the heat content of the coal produced.

(3) Coal carbon content shall be determined at a minimum once each month on one set of daily or per shipment samples collected in paragraph (f)(1) of this section using ASTM D5373 (Test Methods for Instrumental Determination of Carbon Hydrogen and Nitrogen in Laboratory Samples of Coal and Coke).

(4) The individual samples for which both carbon content and GCV were determined according to paragraphs (f)(2) and (f)(3) of this section respectively, shall be used to establish a statistical relationship between the heat content and the carbon content of the coal produced. The owner or operator shall statistically plot the correlation of Btu/lb of coal vs. percent carbon (as a decimal value), where the x-axis is Btu/lb coal and the y-axis is percent carbon (as decimal value), then fit a line to the data points, then calculate the slope and the coefficient of determination, and the R-square (R^2) of that line using the Btu/lb and percent carbon.

(5) Calculation Methodology 2 of this subpart can be used only if all of the following four conditions are met:

(i) At least 12 samples per reporting year from 12 different months of data must be used to construct the correlation graph.

(ii) The correlation graph must be constructed using all paired data points from the first reporting year and all subsequent reporting years.

(iii) There must be a linear relationship between percent carbon and Btu/lb of coal.

(iv) For the second and subsequent years, R-square (R^2) must be greater than or equal to 0.90. This R-square requirement does not apply during the first reporting year.

(6) If all of the conditions specified in paragraph (f)(5) of this section are met, the weighted annual average gross calorific value or higher heating value (Btu/lb) calculated according to Equation KK–3 of this section shall be used to determine the corresponding annual average coal carbon content using the correlation graph plotted according to paragraph (f)(4) of this section.

(h) Reporters complying with Calculation Methodology 3 of this subpart shall determine gross calorific value of the coal by collecting representative daily or per shipment samples of coal using either ASTM D4916–04, D6609–07, D6883–04, D7256/D7256M–06a, or D7430–08; and testing using ASTM D5865–07a, ''Standard Test Method for Gross Calorific Value of Coal and Coke to record the heat content of the coal produced.''

(i) Coal exporters shall calculate carbon content for each shipment of coal using information on the carbon content of the exported coal provided by the source mine, according to Calculation Methodology 1, 2, or 3 of this subpart, as appropriate.

(j) Coal importers shall calculate carbon content for each shipment of coal using Calculation Methodology 1, 2, or 3 of this subpart.

(k) Waste coal reclaimers shall calculate carbon content for each shipment of coal using Calculation Methodology 1, 2, or 3 of this subpart.

(l) Each owner or operator using mechanical coal sampling systems shall perform quality assurance and quality control according to ASTM D4702–07 and ASTM D6518–07.

§ 98.375 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations.

(b) Whenever a quality-assured value for coal production during any time period is unavailable, you must use the average of the parameter values recorded immediately before and after the missing data period in the calculations.

(c) Facilities using Calculation Methodology 1 of this subpart shall develop the statistical relationship between GCV and carbon content according to § 98.274(e), and use this statistical relationship to estimate daily carbon content for any day for which measured carbon content is not available.

(d) Facilities, importers and exporters using Calculation Methodology 2 or 3 of this subpart shall estimate the missing GCV values based on a weighted average value for the previous seven days.

(e) Estimates of missing data shall be documented and records maintained showing the calculations.

§ 98.376 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information.

(a) Each coal mine owner or operator shall report the following information for each coal mine:

(1) The name and MSHA ID number of the mine.

(2) The name of the operating company.

(3) Annual CO_2 emissions.

(4) By rank, the total annual quantity in tons of coal produced.

(5) The annual weighted carbon content of the coal as calculated according to § 98.373.

(6) If Calculation Methodology 1 of this subpart was used to determine CO_2 mass emissions, you must report daily mass fraction of carbon in coal measured by ultimate analysis and daily amount of coal supplied.

(7) If Calculation Methodology 2 of this subpart was used to determine CO_2 mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R^2) value of the correlation.

(8) If Calculation Methodology 3 of this subpart was used to determine CO_2 mass emissions, you must report daily GCV of coal measured by proximate analysis and daily amount of coal supplied.

(b) Coal importers shall report the following information at the corporate level:

(1) The total annual quantity in tons of coal imported into the U.S. by the importer, by rank, and country of origin.

(2) Annual CO_2 emissions.

(3) The annual weighted carbon content of the coal as calculated according to § 98.373.

(4) If Calculation Methodology 1 of this subpart was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(5) If Calculation Methodology 2 of this subpart was used to determine CO_2 mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R^2) value of the correlation.

(6) If Calculation Methodology 3 of this subpart was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

(d) Coal exporters shall report the following information at the corporate level:

(1) The total annual quantity in tons of coal exported from the U.S. by rank and by coal producing company and mine.

(2) Annual CO_2 emissions.

(3) The annual weighted carbon content of the coal as calculated according to § 98.373.

(4) If Calculation Methodology 1 of this subpart was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(5) If Calculation Methodology 2 of this subpart was used to determine CO_2 mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R^2) value of the correlation.

(6) If Calculation Methodology 3 of this subpart was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

(e) Waste coal reclaimers shall report the following information for each reclamation site:

(1) By rank, the total annual quantity in tons of waste coal produced.

(2) Mine and state of origin if waste coal is reclaimed from mines that are no longer operating.

(3) Annual CO_2 emissions.

(4) The annual weighted carbon content of the coal as calculated according to § 98.373.

(5) If Calculation Methodology 1 of this subpart was used to determine CO_2 mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(6) If Calculation Methodology 2 of this subpart was used to determine CO_2 mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squre (R^2) value of the correlation.

(7) If Calculation Methodology 3 of this subpart was used to determine CO_2 mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

§ 98.377 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the following information:

(a) A complete record of all measured parameters used in the reporting of fuel quantities, including all sample results and documentation to support quantities that are reported under this part.

(b) Records documenting all calculations of missing data.

(c) Calculations and worksheets used to estimate the CO_2 emissions.

(d) Calibration records of any instruments used on site and calibration records of scales or other equipment used to weigh coal.

§ 98.378 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE KK–1 OF SUBPART KK—DEFAULT CARBON CONTENT OF COAL FOR METHOD 3 (CO_2 lbs/MMBtu[1])

Weighted annual average GCV of coal Btu/lb[1]	Mass fraction of carbon in coal (decimal)
2,000	0.1140
2,250	0.1283
2,500	0.1425
2,750	0.1568
3,000	0.1710
3,250	0.1853
3,500	0.1995
3,750	0.2138
4,000	0.2280
4,250	0.2423
4,500	0.2565
4,750	0.2708
5,000	0.2850
5,250	0.2993
5,500	0.3135
5,750	0.3278
6,000	0.3420
6,250	0.3563
6,500	0.3705
6,750	0.3848
7,000	0.3990
7,250	0.4133
7,500	0.4275
7,750	0.4418
8,000	0.4560
8,250	0.4703
8,500	0.4845
8,750	0.4988
9,000	0.5130
9,250	0.5273
9,500	0.5415
9,750	0.5558
10,000	0.5700
10,250	0.5843
10,500	0.5985
10,750	0.6128

TABLE KK–1 OF SUBPART KK—DEFAULT CARBON CONTENT OF COAL FOR METHOD 3 (CO_2 lbs/MMBtu[1])—Continued

Weighted annual average GCV of coal Btu/lb[1]	Mass fraction of carbon in coal (decimal)
11,000	0.6270
11,250	0.6413
11,500	0.6555
11,750	0.6698
12,000	0.6840
12,250	0.6983
12,500	0.7125
12,750	0.7268
13,000	0.7410
13,250	0.7553
13,500	0.7695
13,750	0.7838
14,000	0.7980
14,250	0.8123
14,500	0.8265
14,750	0.8408
15,000	0.8550
15,250	0.8693
15,500	0.8835

[1] Based on high heating values.

Subpart LL—Suppliers of Coal-based Liquid Fuels

§ 98.380 Definition of the source category.

This source category consists of producers, importers, and exporters of coal-based liquids.

(a) A producer is the owner or operator of a coal-to-liquids facility. A coal-to-liquids facility is any facility engaged in coverting coal into liquid fuels such as gasoline and diesel using the Fischer-Tropsch process or an alternative process, involving conversion of coal into gas and then into liquids or conversion of coal directly into liquids (direct liquefaction).

(b) An importer or exporter shall have the same meaning given in § 98.6.

§ 98.381 Reporting threshold.

Any supplier of coal-based liquid fuels who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.382 GHGs to report.

You must report the CO_2 emissions that would result from the complete combustion or oxidation of coal-based liquids during the calendar year.

§ 98.383 Calculating GHG emissions.

(a) Coal-to-liquid producers, importers and exporters must calculate CO_2 emissions using Equation LL–1 of this section.

$$CO_2 = \sum \left(Product_i \ * \ EF_i \right) \qquad \text{(Eq. LL-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of fuel (metric tons).

$Product_i$ = Total annual volume (in standard barrels) of a coal-based liquid fuel ''i'' produced, imported, or exported.

EF_i = CO_2 emission factor (metric tons CO_2 per barrel) specific to liquid fuel ''i''.

(b) The emission factor (EF) for each type of coal-based liquid shall be determined using either of the calculation methodologies described in paragraphs (a) and (b) of this section. The same calculation methodology must be used for the entire volume of the product for the reporting year.

(1) *Calculation Methodology 1.* Use the default CO_2 emission factor listed in column C of Table MM–1 of subpart MM (Suppliers of Petroleum Products) that most closely represents the coal-based liquid.

(2) *Calculation Methodology 2.* Develop a CO_2 emission factor according to Equation LL–2 of this section using direct measurement of density and carbon share according to methods set forth in § 98.394(c) or a combination of direct measurement and the default factor listed in columns A or B of Table MM–1 of subpart MM that most closely represents the coal-based liquid.

$$EF = Density \star Wt\% \star (44/12) \qquad \text{(Eq. LL-2)}$$

Where:

EF = Emission factor of coal-based liquid (metric tons CO_2 per barrel).

Density = Density of coal-based liquid (metric tons per barrel).

Wt% = Percent of total mass that carbon represents in coal-based liquid.

§ 98.384 Monitoring and QA/QC requirements.

(a) Producers must measure the quantity of coal-based liquid fuels using procedures for flow meters as described in subpart MM of this part.

(b) Importers and exporters must determine the quantity of coal-based liquid fuels using sales contract information on the volume imported or exported during the reporting period.

(1) The quantity of coal-based liquid fuels must be measured using sales contract information.

(2) The minimum frequency of the measurement of quantities of coal-based liquid fuels shall be the number of sales contracts executed in the reporting period.

(c) All flow meters and product monitors shall be calibrated prior to use for reporting, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, NAESB, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) Reporters shall take the following steps to ensure the quality and accuracy of the data reported under these rules:

(1) For all volumes of coal-based liquid fuels, reporters shall maintain meter and such other records as are normally maintained in the course of business to document fuel flows.

(2) For all estimates of CO_2 mass emissions, reporters shall maintain calculations and worksheets used to calculate the emissions.

§ 98.385 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the reporting of fuel volumes and the calculations of CO_2 mass emissions is required. Therefore, whenever a quality-assured measurement of the quantity of coal-based liquid fuels is unavailable a substitute data value for the missing quantity measurement shall be calculated and used in the calculations.

(b) For coal-to-liquids facilities, the last quality assured reading shall be used. If substantial variation in the flow rate is observed or if a quality assured measurement of quantity is unavailable for any other reason, the average of the last and the next quality assured reading shall be used to calculate a substitute measurement of quantity.

(c) Calculation of substitute data shall be documented and records maintained showing the calculations.

§ 98.386 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Producers shall report the following information for each facility:

(1) The total annual volume of each coal-based liquid supplied to the economy (in standard barrels).

(2) The total annual CO_2 emissions in metric tons associated with each coal-based liquid supplied to the economy, calculated according to § 98.383(a).

(b) Importers shall report the following information at the corporate level:

(1) The total annual volume of each imported coal-based liquid (in standard barrels).

(2) The total annual CO_2 emissions in metric tons associated with each imported coal-based liquid, calculated according to § 98.383(a).

(c) Exporters shall report the following information at the corporate level:

(1) The total annual volume of each exported coal-based liquid (in standard barrels).

(2) The total annual CO_2 emissions in metric tons associated with each exported coal-based liquid, calculated according to § 98.383(a).

§ 98.387 Records that must be retained.

Reporters shall retain copies of all reports submitted to EPA. Reporters shall maintain records to support volumes that are reported under this part, including records documenting any calculation of substitute measured data. Reporters shall also retain calculations and worksheets used to estimate the CO_2 equivalent of the volumes reported under this part. These records shall be retained for five (5) years similar to 40 CFR part 80 fuels compliance reporting program.

§ 98.388 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart MM—Suppliers of Petroleum Products

§ 98.390 Definition of the source category.

This source category consists of petroleum refineries and importers and exporters of petroleum products.

(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(b) A refiner is the owner or operator of a petroleum refinery.

(c) Importer has the same meaning given in § 98.6 and includes any blender or refiner of refined or semi-refined petroleum products.

(d) Exporter has the same meaning given in § 98.6 and includes any blender or refiner of refined or semi-refined petroleum products.

§ 98.391 Reporting threshold.

Any supplier of petroleum products who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.392 GHGs to report.

You must report the 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. Additionally, if you are a refiner, you must report CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks.

§ 98.393 Calculating GHG emissions.

(a) Except as provided in paragraph (g) of this section, any refiner, importer, or exporter shall calculate CO_2 emissions from each individual petroleum product and natural gas liquid using Equation MM–1 of this section.

$$CO_{2i} = Product_i \star EF_i \qquad \text{(Eq. MM-1)}$$

Where:

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid ‘‘i’’ (metric tons).

$Product_i$ = Total annual volume of product ‘‘i’’ produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

(b) Except as provided in paragraph (g) of this secton, any refiner shall calculate CO_2 emissions from each non-crude feedstock using Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j \star EF_j \qquad \text{(Eq. MM-2)}$$

Where:

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of each non-crude feedstock ‘‘j’’ (metric tons).

$Feedstock_j$ = Total annual volume of a petroleum product or natural gas liquid ‘‘j’’ that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels). Any waste feedstock (see definitions) that enters the refinery must also be included.

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

(c) Refiners shall calculate CO_2 emissions from all biomass co-processed with petroleum feedstocks using Equation MM–3 of this section.

$$CO_{2m} = Biomass_m \star EF_m \qquad \text{(Eq. MM-3)}$$

Where:

CO_{2m} = Annual potential CO_2 emissions from the complete combustion or oxidation of biomass ‘‘m’’ (metric tons).

$Biomass_m$ = Total annual volume of a specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).

EF_m = Biomass-specific CO_2 emission factor (metric tons CO_2 per barrel).

(d) Refiners shall calculate total CO_2 emissions from all products using Equation MM–4 of this section.

$$CO_{2r} = \sum(CO_{2i}) - \sum(CO_{2j}) - \sum(CO_{2m}) \qquad \text{(Eq. MM-4)}$$

Where:

CO_{2r} = Total annual potential CO_2 emissions from the complete combustion or oxidation of all petroleum products and natural gas liquids (ex refinery gate) minus non-crude feedstocks and any biomass to be co-processed with petroleum feedstocks.

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

CO_{2m} = Annual potential CO_2 emissions from the complete combustion or oxidation of biomass "m" (metric tons).

(e) Importers and exporters shall calculate total CO_2 emissions from all petroleum products and natural gas liquids imported or exported, respectively, using Equations MM–1 and MM–5 of this section.

$$CO_{2x} = \sum(CO_{2i}) \qquad \text{(Eq. MM-5)}$$

Where:

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2x} = Total annual potential CO_2 emissions from the complete combustion or oxidation of all petroleum products and natural gas liquids.

(f) Except as provided in paragraph (g) of this section, the emission factor (EF) for each petroleum product and natural gas liquid shall be determined using either of the calculation methodologies described in paragraphs (f)(1) or (f)(2) of this section. The same calculation methodology must be used for the entire volume of the product for the reporting year.

(1) *Calculation Methodology 1.* Use the appropriate default CO_2 emission factors listed in column C of Tables MM–1 and MM–2 of this subpart.

(2) *Calculation Methodology 2.* Develop emission factors according to Equation MM–6 of this section using direct measurements of density and carbon share according to methods set forth in § 98.394(c) or a combination of direct measurements and default factors listed in columns A and B of Tables MM–1 and MM–2 of this subpart.

$$EF = Density \star Wt\% \star (44/12) \qquad \text{(Eq. MM-6)}$$

Where:

EF = Emission factor of petroleum or natural gas product or non-crude feedstock (metric tons CO_2 per barrel).

Density = Density of petroleum product or natural gas liquid or non-crude feedstock (metric tons per barrel).

Wt% = Percent of total mass that carbon represents in petroleum product or natural gas liquid or non-crude feedstock.

44/12 = Conversion factor for carbon to carbon dioxide.

(g) In the event that some portion of a petroleum product or feedstock is biomass-based and was not derived by co-processing biomass and petroleum feedstocks together (i.e., the petroleum product or feedstock was produced by blending a petroleum-based product with a biomass-based product), the reporting party shall calculate emissions for the petroleum product or feedstock according to one of the methods in paragraph (g)(1) or (2) of this section, as appropriate.

(1) A reporting party using Calculation Methodology 1 of this subpart to determine the emission factor of a petroleum product shall calculate the CO_2 emissions associated with that product using Equation MM–7 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = Product_i \star EF_i \star \%Vol_i \qquad \text{(Eq. MM-7)}$$

Where:

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of petroleum product "i" (metric tons).

$Product_i$ = Total annual volume of petroleum product "i" produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Petroleum product-specific CO_2 emission factor (metric tons CO_2 per barrel) from MM–1.

$\%Vol_i$ = Percent volume of product "i" that is petroleum-based.

(2) A refinery using Calculation Methodology 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO_2 emissions associated with that feedstock using Equation MM–8 in place of Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j \star EF_j \star \%Vol_j \qquad \text{(Eq. MM-8)}$$

Where:

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

$Feedstock_j$ = Total annual volume of a petroleum product "j" that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels).

EF_j = Non-crude petroleum feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

$\%Vol_j$ = Percent volume of feedstock "j" that is petroleum-based.

(3) A reporter using Calculation Methodology 2 of this subpart to determine the emission factor of a petroleum product must calculate the CO_2 emissions associated with that product using Equation MM–9 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = \left(Product_i \star EF_i\right) - \left(Product_i \star EF_m \star \%Vol_m\right) \qquad \text{(Eq. MM-9)}$$

Where:

CO_2i = Annual potential CO_2 emissions from the complete combustion or oxidation of product ''i'' (metric tons).

$Product_i$ = Total annual volume of petroleum product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–3 that most closely represents the component of product ''i'' that is biomass-based.

$\%Vol_m$ = Percent volume of petroleum product ''i'' that is biomass-based.

(4) A refiner using Calculation Methodology 2 of this subpart to determine the emission factor of a non-crude petroleum feedstock must calculate the CO_2 emissions associated with that feedstock using Equation MM–10 in place of Equation MM–2 of this section.

$$CO_{2j} = \left(Feedstock_j \star EF_j\right) - \left(Feedstock_i \star EF_m \star \%Vol_m\right) \qquad \text{(Eq. MM-10)}$$

Where:

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Total annual volume of non-crude feedstock ''j'' that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels). Any waste feedstock (see definitions) that enters the refinery must also be included.

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–3 of subpart MM that most closely represents the component of product ''i'' that is biomass-based.

$\%Vol_m$ = Percent volume of non-crude feedstock ''j'' that is biomass-based.

(h) Refiners shall use the most appropriate default CO_2 emission factor (EF_m) for biomass in Table MM–3 to calculate CO_2 emissions in paragraph (c) of this section.

§ 98.394 Monitoring and QA/QC requirements.

(a) The quantity of petroleum products, natural gas liquids, biomass, and all feedstocks shall be determined using either a flow meter or tank gauge, depending on the reporters existing equipment and preferences.

(1) For flow meters any one of the following test methods can be used to determine quantity:

(i) Ultra-sonic flow meter: *AGA Report No. 9 (2007)*

(ii) Turbine meters: American National Standards Institute, *ANSI/ASME MFC–4M–1986*

(iii) Orifice meters: American National Standards Institute, *AINSI/API 2530 (also called AGA–3) (1991)*

(iv) Coriolis meters: *ASME MFC–11 (2006)*

(2) For tank gauges any one of the following test methods can be used to determine quantity:

(i) API–2550: Measurements and Calibration of Petroleum Storage Tanks (1965)

(ii) API MPMS 2.2: A Manual of Petroleum Measurement Standards (1995)

(iii) API–653: Tank Inspection, Repair, Alteration and Reconstruction, 3rd edition (2008)

(b) All flow meters and tank gauges shall be calibrated prior to use for reporting, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, or NAESB). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Product flow meters and tank gauges shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(c) For Calculation Methodology 2 of this subpart, samples of each petroleum product and natural gas liquid shall be taken each month for the reporting year. The composite sample shall be tested at the end of the reporting year using ASTM D1298 (2003), ASTM D1657–02 (2007), ASTM D4052–96 (2002)el, ASTM D5002–99 (2005), or ASTM D5004–89 (2004)el for density, as appropriate, and ASTM D5291 (2005) or ASTM D6729–(2004)el for carbon share, as appropriate (see Technical Support Document). Reporters must sample seasonal gasoline each month of the season and then test the composite sample at the end of the season.

§ 98.395 Procedures for estimating missing data.

Whenever a metered or quality-assured value of the quantity of petroleum products, natural gas liquids, biomass, or feedstocks during any period is unavailable, a substitute data value for the missing quantity measurement shall be used in the calculations contained in § 98.393.

(a) For marine-imported and exported refined and semi-refined products, the reporting party shall attempt to reconcile any differences between ship and shore volume readings. If the reporting party is unable to reconcile the readings, the higher of the two volume values shall be used for emission calculation purposes.

(b) For pipeline imported and exported refined and semi-refined products, the last valid volume reading based on the company's established procedures for purposes of product tracking and billing shall be used. If the pipeline experiences substantial variations in flow rate, the average of the last valid volume reading and the next valid volume reading shall be used for emission calculation purposes.

(c) For petroleum refineries, the last valid volume reading based on the facility's established procedures for purposes of product tracking and billing shall be used. If substantial variation in the flow rate is observed, the average of the last and the next valid volume reading shall be used for emission calculation purposes.

§ 98.396 Data reporting requirements.

In addition to the information required by § 98.3(c), the following requirements apply.

(a) Refiners shall report the following information for each facility:

(1) CO_2 emissions in metric tons for each petroleum product and natural gas liquid (ex refinery gate), calculated according to § 98.393(a) or (g).

(2) CO_2 emissions in metric tons for each petroleum product or natural gas liquid that enters the refinery annually as a feedstock to be further refined or otherwise used on site, calculated according to § 98.393(b) or (g).

(3) CO_2 emissions in metric tons from each type of biomass feedstock co-processed with petroleum feedstocks, calculated according to § 98.393(c).

(4) The total sum of CO_2 emissions from all products, calculated according to § 98.393(d).

(5) The total volume of each petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraphs (a)(1)

and (2) of this section, seperately, and the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If a determination cannot be made whether the material is a petroleum product or a natural gas liquid, it shall be reported as a petroleum product.

(6) The total volume of any biomass co-processed with a petroleum product associated with the CO_2 emissions reported in paragraph (a)(3) of this section.

(7) The measured density and/or mass carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(8) The total volume of each distillate fuel oil product or feedstock reported in paragraph (a)(5) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

(9) All of the following information for all crude oil feedstocks used at the refinery:

(i) Batch volume (in standard barrels).

(ii) API gravity of the batch.

(iii) Sulfur content of the batch.

(iv) Country of origin of the batch.

(b) In addition to the information required by § 98.3(c), each importer shall report all of the following information at the corporate level:

(1) CO_2 emissions in metric tons for each imported petroleum product and natural gas liquid, calculated according to § 98.393(a).

(2) Total sum of CO_2 emissions, calculated according to § 98.393(e).

(3) The total volume of each imported petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraph (b)(1) of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product.

(4) The measured density and/or mass carbon share for any imported petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(5) The total volume of each distillate fuel oil product reported in paragraph (b)(1) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

(c) In addition to the information required by § 98.3(c), each exporter shall report all of the following information at the corporate level:

(1) CO_2 emissions in metric tons for each exported petroleum product and natural gas liquid, calculated according to § 98.393(a).

(2) Total sum of CO_2 emissions, calculated according to § 98.393(e).

(3) The total volume of each exported petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraph (c)(1) of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product.

(4) The measured density and/or mass carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(5) The total volume of each distillate fuel oil product reported in paragraph (c)(1) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

§ 98.397 Records that must be retained.

(a) Any reporter described in § 98.391 shall retain copies of all reports submitted to EPA under § 98.396. In addition, any reporter under this subpart shall maintain sufficient records to support information contained in those reports, including but not limited to information on the characteristics of their feedstocks and products.

(b) Reporters shall maintain records to support volumes that are reported under this part, including records documenting any estimations of missing metered data. For all volumes of petroleum products, natural gas liquids, biomass, and feedstocks, reporters shall maintain meter and other records normally maintained in the course of business to document product and feedstock flows.

(c) Reporters shall also retain laboratory reports, calculations and worksheets used to estimate the CO_2 emissions of the volumes reported under this part.

(d) Estimates of missing data shall be documented and records maintained showing the calculations.

(e) Reporters described in this subpart shall also retain all records described in § 98.3(g).

§ 98.398 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE MM–1 OF SUBPART MM—DEFAULT CO_2 FACTORS FOR PETROLEUM PRODUCTS [1, 2]

Refined and semi-refined petroleum products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl) [Column A * Column B/100 * 44/12]
Motor Gasoline [3]			
Conventional—Summer	0.12	86.96	0.38
Conventional—Winter	0.12	86.96	0.37
Reformulated—Summer	0.12	86.60	0.37
Reformulated—Winter	0.12	86.60	0.37
Finished Aviation Gasoline	0.11	85.00	0.35

TABLE MM–1 OF SUBPART MM—DEFAULT CO$_2$ FACTORS FOR PETROLEUM PRODUCTS [1, 2]—Continued

Refined and semi-refined petroleum products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO$_2$/bbl) [Column A * Column B/100 * 44/12]
Blendstocks			
RBOB	0.12	86.60	0.38
CBOB	0.12	85.60	0.37
Others	0.11	84.00	0.34
Oxygenates			
Methanol	0.13	37.50	0.17
GTBA	0.12	64.90	0.29
t-butanol	0.12	64.90	0.29
MTBE	0.12	68.20	0.29
ETBE	0.12	70.50	0.30
TAME	0.12	70.50	0.31
DIPE	0.12	70.60	0.30
Kerosene-Type Jet Fuel	0.13	86.30	0.41
Naptha-Type Jet Fuel	0.12	85.80	0.39
Kerosene	0.13	86.01	0.41
Distillate Fuel Oil			
Diesel No. 1	0.13	86.40	0.43
Diesel No. 2	0.13	86.34	0.43
Diesel No. 4	0.15	86.47	0.46
Fuel Oil No. 1	0.13	86.40	0.43
Fuel Oil No. 2	0.13	86.34	0.43
Fuel Oil No. 4	0.15	86.47	0.46
Residual Fuel Oil No. 5 (Navy Special)	0.14	85.81	0.43
Residual Fuel Oil No. 6 (a.k.a. Bunker C)	0.16	85.68	0.49
Petrochemical Feedstocks			
Naphthas (< 401 °F)	0.12	84.11	0.36
Other Oils (> 401 °F)	0.13	86.34	0.43
Special Naphthas	0.12	84.76	0.38
Lubricants	0.14	85.80	0.45
Waxes	0.13	85.29	0.40
Petroleum Coke	0.07	92.28	0.23
Asphalt and Road Oil	0.16	83.47	0.50
Still Gas	0.07	24.40	0.06
Ethane	0.06	80.00	0.17
Ethylene	0.09	85.71	0.28
Propane	0.08	81.80	0.24
Propylene	0.08	85.71	0.26
Butane	0.09	82.80	0.28
Butylene	0.11	85.71	0.35
Isobutane	0.09	82.80	0.27
Isobutylene	0.09	85.71	0.29
Pentanes Plus	0.11	83.70	0.32
Miscellaneous Products	0.14	85.49	0.43
Unfinished Oils	0.14	85.49	0.43
Naphthas	0.12	85.70	0.37
Kerosenes	0.13	85.80	0.41
Heavy Gas Oils	0.15	85.80	0.46
Residuum	0.16	85.70	0.51
Waste Feedstocks	0.14	85.70	0.45

[1] In the case of transportation fuels blended with some portion of biomass-based fuel, the carbon share in Table MM–1 represents only the petroleum-based components.

[2] Products that are derived entirely from biomass should not be reported, but products that were derived from both biomass and a petroleum product (i.e., co-processed) should be reported as the petroleum product that it most closely represents.

TABLE MM–2 OF SUBPART MM—DEFAULT CO_2 FACTORS FOR NATURAL GAS LIQUIDS

Natural gas liquids	Column A: density tonnes/barrel	Column B: carbon share (% of mass)	Column C: computed emission factor (tonnes CO_2/bbl) [Column A * Column B/100 * 44/12]
C2+	0.08	81.79	0.24
C4+	0.10	83.15	0.30
C5+	0.11	83.70	0.32
C6+	0.11	84.04	0.34

TABLE MM–3 OF SUBPART MM—DEFAULT CO_2 FACTORS FOR BIOMASS-BASED FUEL AND BIOMASS FEEDSTOCK

Biomass products and feedstock	Column A: emission factor (tonnes CO_2/bbl)
Ethanol (100%)	0.23
Biodiesel (100%, methyl ester)	0.40
Rendered Animal Fat	0.37
Vegetable Oil	0.41

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

§ 98.400 Definition of the source category.

This supplier category consists of natural gas processing plants and local natural gas distribution companies.

(a) Natural Gas Processing Plants are installations designed to separate and recover natural gas liquids (NGLs) or other gases and liquids from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods and to control the quality of natural gas marketed. This does not include field gathering and boosting stations.

(b) Local Distribution Companies are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.

§ 98.401 Reporting threshold.

Any supplier of natural gas and natural gas liquids that meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.402 GHGs to report.

(a) Natural gas processing plants must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutane and bulk NGLs sold or delivered for use off site.

(b) Local distribution companies must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users.

§ 98.403 Calculating GHG emissions.

(a) For each type of fuel or product reported under this part, calculate the estimated CO_2 equivalent emissions using either of Calculation Methodology 1 or 2 of this subpart:

(1) *Calculation Methodology 1.* Estimate CO_2 emissions using Equation NN–1. For Equation NN–1, use the default values for higher heating values and CO_2 emission factors in Table NN–1 to this subpart. Alternatively, reporter-specific higher heating values and CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404. For Equation NN–2 of this section, use the default values for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_2 = 1 \times 10^{-3} \star Fuel \star HHV \star EF \qquad \text{(Eq. NN-1)}$$

Where:

CO_2 = Annual potential CO_2 mass emissions from the combustion of fuel (metric tons).

Fuel = Total annual volume of fuel or product (volume per year, typically in Mcf for gaseous fuels and bbl for liquid fuels).

HHV = Higher heat value of the fuel supplied (MMBtu/Mcf or MMBtu/bbl).

EF = Fuel-specific CO_2 emission factor (kg CO_2/MMBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons (MT/kg).

(2) *Calculation Methodology 2.* Estimate CO_2 emissions using Equation NN–2.

$$CO_2 = Fuel \star EF \qquad \text{(Eq. NN-2)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of fuel supplied (metric tons)

Fuel = Total annual volume of fuel or product supplied (bbl or Mcf per year)

EF = Fuel-specific CO_2 emission factor (MT CO_2/bbl, or MT CO_2/Mcf)

§ 98.404 Monitoring and QA/QC requirements.

(a) The quantity of natural gas liquids and natural gas must be determined using any of the oil and gas flow meter test methods that are in common use in the industry and consistent with the Gas Processors Association Technical Manual and the American Gas Association Gas Measurement Committee reports.

(b) The minimum frequency of the measurements of quantities of natural gas liquids and natural gas shall be based on the industry standard practices for commercial operations. For natural gas liquids these are measurements taken at custody transfers summed to the annual reportable volume. For natural gas these are daily totals of continuous measurements, and summed to the annual reportable volume.

(c) All flow meters and product or fuel composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by the American Gas Association Gas Measurement Committee reports on flow metering and heating value calculations and the Gas Processors Association standards on measurement and heating value. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) Reporter-specific emission factors or higher heating values shall be determined using industry standard practices such as the American Gas Association (AGA) Gas Measurement Committee Report on heating value and the Gas Processors Association (GPA) Technical Standards Manual for NGL heating value; and ASTM D–2597–94 and ASTM D–1945–03 for compositional analysis necessary for estimating CO_2 emission factors.

§ 98.405 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the reporting of fuel volumes and in the calculations of CO_2 mass emissions is required. Therefore, whenever a quality-assured value of the quantity of natural gas liquids or natural gas during any period is unavailable (e.g., if a flow meter malfunctions), a substitute data value for the missing quantity measurement must be used in the calculations according to paragraphs (b) and (c) of this section.

(b) For NGLs, natural gas processing plants shall substitute meter records provided by pipeline(s) for all pipeline receipts of NGLs; by manifests for deliveries made to trucks or rail cars; or metered quantities accepted by the entities purchasing the output from the processing plant whether by pipeline or by truck or rail car. In cases where the metered data from the receiving pipeline(s) or purchasing entities are not available, natural gas processors may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(c) Natural gas local distribution companies may substitute the metered quantities from the delivering pipelines for all deliveries into the distribution system. In cases where the pipeline metered delivery data are not available, local distribution companies may substitute their pipeline nominations and scheduled quantities for the period when metered values of actual deliveries are not available.

(d) Estimates of missing data shall be documented and records maintained showing the calculations of the values used for the missing data.

§ 98.406 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the annual report for each natural gas processing plant must contain the following information.

(1) The total annual quantity in barrels of NGLs produced for sale or delivery on behalf of others in the following categories: Propane, natural butane, ethane, and isobutane, and all other bulk NGLs as a single category.

(2) The total annual CO_2 mass emissions associated with the volumes in paragraph (a)(1) of this section and calculated in accordance with § 98.403.

(b) In addition to the information required by § 98.3(c), the annual report for each local distribution company must contain the following information.

(1) The total annual volume in Mcf of natural gas received by the local distribution company for redelivery to end users on the local distribution company's distribution system.

(2) The total annual CO_2 mass emissions associated with the volumes in paragraph (b)(1) of this section and calculated in accordance with § 98.403.

(3) The total natural gas volumes received for redelivery to downstream gas transmission pipelines and other local distribution companies.

(4) The name and EPA and EIA identification code of each individual covered facility, and the name and EIA identification code of any other end-user for which the local gas distribution company delivered greater than or equal to 460,000 Mcf during the calendar year, and the total natural gas volumes actually delivered to each of these end-users.

(5) The annual volume in Mcf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 and Instructions.

(i) Residential consumers.

(ii) Commercial consumers.

(iii) Industrial consumers.

(iv) Electricity generating facilities.

(6) The total annual CO_2 mass emissions associated with the volumes in paragraph (b)(5) of this section and calculated in accordance with § 98.403.

§ 98.407 Records that must be retained.

In addition to the information required by § 98.3(g), each annual report must contain the following information:

(a) Records of all daily meter readings and documentation to support volumes of natural gas and NGLs that are reported under this part.

(b) Records documenting any estimates of missing metered data.

(c) Calculations and worksheets used to estimate CO_2 emissions for the volumes reported under this part.

(d) Records related to the large end-users identified in § 98.406(b)(4).

(e) Records relating to measured Btu content or carbon content.

§ 98.408 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE NN–1 OF SUBPART NN—DEFAULT FACTORS FOR CALCULATION METHODOLOGY 1 OF THIS SUBPART

Fuel	Default high heating value factor	Default CO_2 emission factor (kg CO_2/MMBtu)
Natural Gas	1.027 MMBtu/Mcf	53.02
Propane	3.836 MMBtu/bbl	63.02
Butane	4.326 MMBtu/bbl	64.93

TABLE NN–1 OF SUBPART NN—DEFAULT FACTORS FOR CALCULATION METHODOLOGY 1 OF THIS SUBPART—Continued

Fuel	Default high heating value factor	Default CO_2 emission factor (kg CO_2/MMBtu)
Ethane	3.082 MMBtu/bbl	59.58
Isobutane	3.974 MMBtu/bbl	65.08
Natural Gas Liquids	4.140 MMBtu/bbl	63.20

TABLE NN–2 OF SUBPART NN—LOOKUP DEFAULT VALUES FOR CALCULATION METHODOLOGY 2 OF THIS SUBPART

Fuel	Unit	Default CO_2 emission value (MT CO_2/Unit)
Natural Gas	Mcf	0.054452
Propane	Barrel	0.241745
Butane	Barrel	0.280887
Ethane	Barrel	0.183626
Isobutane	Barrel	0.258628
Natural Gas Liquids	Barrel	0.261648

Subpart OO—Suppliers of Industrial Greenhouse Gases

§ 98.410 Definition of the source category.

(a) The industrial gas supplier source category consists of any facility that produces a fluorinated GHG or nitrous oxide, any bulk importer of fluorinated GHGs or nitrous oxide, and any bulk exporter of fluorinated GHGs or nitrous oxide.

(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHGs does not include the reuse or recycling of a fluorinated GHG or the generation of HFC–23 during the production of HCFC–22.

(c) *To produce nitrous oxide* means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH_4NO_3). Producing nitrous oxide does not include the reuse or recycling of nitrous oxide or the creation of by-products that are released or destroyed at the production facility.

§ 98.411 Reporting threshold.

Any supplier of industrial greenhouse gases who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.412 GHGs to report.

You must report the GHG emissions that would result from the release of the nitrous oxide and each fluorinated GHG that you produce, import, export, transform, or destroy during the calendar year.

§ 98.413 Calculating GHG emissions.

(a) The total mass of each fluorinated GHG or nitrous oxide produced annually shall be estimated by using Equation OO–1 of this section:

$$P = \sum_{p=1}^{n} P_p \qquad \text{(Eq. OO-1)}$$

Where:

P = Mass of fluorinated GHG or nitrous oxide produced annually.

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period “p”.

(b) The total mass of each fluorinated GHG or nitrous oxide produced over the period “p” shall be estimated by using Equation OO–2 of this section:

$$P_p = O_p - U_p \qquad \text{(Eq. OO-2)}$$

Where:

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period “p” (metric tons).

O_p = Mass of fluorinated GHG or nitrous oxide that is measured coming out of the production process over the period p (metric tons).

U_p = Mass of used fluorinated GHG or nitrous oxide that is added to the production process upstream of the output measurement over the period “p” (metric tons).

(c) The total mass of each fluorinated GHG or nitrous oxide transformed shall be estimated by using Equation OO–3 of this section:

$$T = F_T - R \qquad \text{(Eq. OO-3)}$$

Where:

T = Mass of fluorinated GHG or nitrous oxide transformed annually (metric tons).

F_T = Mass of fluorinated GHG fed into the transformation process annually (metric tons).

R = Mass of residual, unreacted fluorinated GHG or nitrous oxide that is permanently removed from the transformation process (metric tons).

(d) The total mass of each fluorinated GHG destroyed shall be estimated by using Equation OO–4 of this section:

$$D = F_D * DE \qquad \text{(Eq. OO-4)}$$

Where:

D = Mass of fluorinated GHG destroyed annually (metric tons).

F_D = Mass of fluorinated GHG fed into the destruction device annually (metric tons).

DE = Destruction efficiency of the destruction device (fraction).

§ 98.414 Monitoring and QA/QC requirements.

(a) The mass of fluorinated GHGs or nitrous oxide coming out of the production process shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(b) The mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in paragraph (a) of this section shall be measured at least daily (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(c) The mass of fluorinated GHGs or nitrous oxide fed into transformation processes shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(d) If unreacted fluorinated GHGs or nitrous oxide are permanently removed (recovered, destroyed, or emitted) from the transformation process, the mass removed shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the unreacted fluorinated GHG or nitrous oxide, the concentration of the unreacted fluorinated GHG or nitrous oxide shall be measured at least daily using equipment and methods (*e.g.*, gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG or nitrous oxide permanently removed from the transformation process.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG, the concentration of the fluorinated GHG shall be measured at least daily using equipment and methods (*e.g.*, gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG sent to another facility for destruction.

(g) The mass of fluorinated GHGs fed into the destruction device shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, the concentrations of fluorinated GHG being destroyed shall be measured at least daily using equipment and methods (*e.g.*, gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG destroyed.

(h) For purposes of Equation OO–4, the destruction efficiency can initially be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device. Fluorinated GHG production facilities that destroy fluorinated GHGs shall conduct annual measurements of mass flow and fluorinated GHG concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of fluorinated GHGs being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.413, or

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.413.

(i) In their estimates of the mass of fluorinated GHGs destroyed, designated representatives of fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(j) All flowmeters, weigh scales, and combinations of volumetric and density measurements that are used to measure or calculate quantities that are to be reported under this subpart shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (*e.g.*, ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(k) All gas chromatographs that are used to measure or calculate quantities that are to be reported under this subpart shall be calibrated at least monthly through analysis of certified standards with known concentrations of the same chemical(s) in the same range(s) (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

§ 98.415 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (*e.g.*, if a meter malfunctions), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the mass produced, fed into the production process (for used material being reclaimed), fed into transformation processes, fed into destruction devices, sent to another facility for transformation, or sent to another facility for destruction, the substitute value of that parameter shall be a secondary mass measurement. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product.

(2) For each missing value of fluorinated GHG concentration, except the annual destruction device outlet concentration measurement specified in § 98.414(h), the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-

assured value obtained after the missing data period. There are no missing value allowances for the annual destruction device outlet concentration measurement. A re-test must be performed if the data from the annual destruction device outlet concentration measurement are determined to be unacceptable or not representative of typical operations.

(3) Notwithstanding paragraphs (a)(1) and (2) of this section, if the owner or operator has reason to believe that the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing, the designated representative of the fluorinated GHG production facility shall develop his or her best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in paragraphs (a)(1) and (2) of this section would probably lead to a significant under- or overestimate of the parameter. EPA may reject the alternative estimate and replace it with an estimate based on the applicable method in paragraph (a)(1) or (2) if EPA does not agree with the rationale or method for the alternative estimate.

§ 98.416 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information at the facility level:

(1) Total mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility.

(2) Total mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility.

(3) Total mass in metric tons of each fluorinated GHG destroyed at that facility.

(4) Total mass in metric tons of any fluorinated GHG or nitrous oxide sent to another facility for transformation.

(5) Total mass in metric tons of any fluorinated GHG sent to another facility for destruction.

(6) Total mass in metric tons of each reactant fed into the production process.

(7) Total mass in metric tons of each non-GHG reactant and by-product permanently removed from the process.

(8) Mass of used product added back into the production process (e.g., for reclamation).

(9) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(10) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for destruction.

(11) Where missing data have been estimated pursuant to § 98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data. Where the missing data have been estimated pursuant to § 98.415(a)(3), the report shall explain the rationale for the methods used to estimate the missing data and why the methods specified in § 98.415(a)(1) and (2) would lead to a significant under- or overestimate of the parameters.

(b) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate calculated from (b)(2) and (b)(3) in kg/hr.

(c) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Test methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

(d) A bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their imports at the corporate level, except for transshipments and heels. The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(7) Importer number for the shipment.

(8) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation.

(9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.

(e) A bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their exports at the corporate level, except for transshipments and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter's Employee Identification Number.

(4) Quantity exported by chemical in metric tons of chemical.

(5) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(6) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories.

(7) Country to which the fluorinated GHGs or nitrous oxide were exported.

§ 98.417 Records that must be retained.

(a) In addition to the data required by § 98.3(g), the designated representative of a fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under § 98.416, and

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to § 98.414(j) and (k).

(b) In addition to the data required by paragraph (a) of this section, the designated representative of a fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report and annual destruction device outlet reports in § 98.416(b) and (c).

(c) In addition to the data required by § 98.3(g), the designated representative of a bulk importer shall retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(d) In addition to the data required by § 98.3(g), the designated representative of a bulk exporter shall retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the import.

(e) Every person who imports a container with a heel shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:

(1) Remain in the container and be included in a future shipment.

(2) Be recovered and transformed.

(3) Be recovered and destroyed.

§ 98.418 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart PP—Suppliers of Carbon Dioxide

§ 98.420 Definition of the source category.

(a) The carbon dioxide (CO_2) supplier source category consists of the following:

(1) Production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications. Capture refers to the separation and removal of CO_2 from a manufacturing process; fuel combustion source; or a waste, wastewater, or water treatment process.

(2) Facilities with CO_2 production wells.

(3) Importers or exporters of bulk CO_2.

(b) This source category does not include the following:

(1) Geologic sequestration (long term storage) of CO_2.

(2) Injection and subsequent production and/or processing of CO_2 for enhanced oil and gas recovery.

(3) Above ground storage of CO_2.

(4) Transportation or distribution of CO_2 via pipelines, vessels, motor carriers, or other means.

(5) Purification, compression, or processing of CO_2.

(6) CO_2 imported or exported in equipment.

§ 98.421 Reporting threshold.

Any supplier of CO_2 who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.422 GHGs to report.

You must report the mass of carbon dioxide captured from production process units, the mass of carbon dioxide extracted from carbon dioxide production wells, and the mass of carbon dioxide imported and exported regardless of the degree of impurities in the carbon dioxide stream.

§ 98.423 Calculating GHG emissions.

(a) Facilities with production process units must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream in metric tons captured, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP–1 of this section. Mass flow and composition data measurements are made in accordance with § 98.424.

$$CO_2 = \sum_{p=1}^{4} Q * C_{CO_2} \qquad \text{(Eq. PP-1)}$$

Where:

CO_2 = CO_2 mass emission (metric tons per year).

C_{CO2} = Quarterly average CO_2 concentration in flow (wt. % CO_2).

Q = Quarterly mass flow rate (metric tons per quarter).

(b) CO_2 production well facilities must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream from wells in metric tons, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP–1. Mass flow and composition data measurements are made in accordance with § 98.424.

(c) Importers or exporters of a carbon dioxide stream must calculate quarterly the total mass of carbon dioxide imported or exported in metric tons, based on multiplying the mass flow by the composition data, according to Equation PP–1. Mass flow and composition data measurements are made in accordance with § 98.424. The quantities of CO_2 imported or exported in equipment, such as fire extinguishers, need not be calculated or reported.

§ 98.424 Monitoring and QA/QC requirements.

(a) Facilities with production process units that capture a carbon dioxide stream must measure on a quarterly basis using a mass flow meter the mass flow of the CO_2 stream captured. If production process units do not have mass flow meters installed to measure the mass flow of the CO_2 stream captured, measurements shall be based on the mass flow of gas transferred off site using a mass flow meter. In either case, sampling also must be conducted on at least a quarterly basis to determine the composition of the captured or transferred CO_2 stream.

(b) Carbon dioxide production well facilities must measure on a quarterly basis the mass flow of the CO_2 stream extracted using a mass flow meter. If the CO_2 production wells do not have mass flow meters installed to measure the mass flow of the CO_2 stream extracted, measurements shall be based on mass flow of gas transferred off site using a mass flow meter. In either case, sampling must be conducted on at least a quarterly basis to determine the composition of the extracted or transferred carbon dioxide.

(c) Importers or exporters of bulk CO_2 must measure on a quarterly basis the mass flow of the CO_2 stream imported or exported using a mass flow meter and must conduct sampling on at least a quarterly basis to determine the composition of the imported or exported CO_2 stream. If the importer of a CO_2 stream does not have mass flow meters installed to measure the mass flow of gas imported, the measurements shall be based on the mass flow of the imported CO_2 stream transferred off site or used in on-site processes, as measured by mass flow meters. If an exporter of a CO_2 stream does not have mass flow meters installed to measure the mass flow exported, the measurements shall be based on the mass flow of the CO_2 stream received for export, as measured by mass flow meters. In all cases, sampling on at least a quarterly basis also must be conducted to determine the composition of the CO_2 stream.

(d) Mass flow meter calibrations must be NIST traceable.

(e) Methods to measure the composition of the carbon dioxide captured, extracted, transferred, imported, or exported must conform to applicable chemical analytical standards. Acceptable methods include U.S. Food and Drug Administration food-grade specifications for carbon dioxide (see 21 CFR 184.1250) and ASTM standard E–1745–95 (2005).

§ 98.425 Procedures for estimating missing data.

(a) Missing quarterly monitoring data on mass flow of CO_2 streams captured, extracted, imported, or exported shall be substituted with the greater of the following values:

(1) Quarterly CO_2 mass flow of gas transferred off site measured during the current reporting year.

(2) Quarterly or annual average values of the monitored CO_2 mass flow from the past calendar year.

(b) Missing monitoring data on the mass flow of the CO_2 stream transferred off site shall be substituted with the quarterly or annual average values from off site transfers from the past calendar year.

(c) Missing data on composition of the CO_2 stream captured, extracted, transferred, imported, or exported may be substituted for with quarterly or annual average values from the past calendar year.

§ 98.426 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information.

(a) Each facility with production process units or CO_2 production wells must report the following information:

(1) Total annual mass in metric tons and the weighted average composition of the CO_2 stream captured, extracted, or transferred in either gas, liquid, or solid forms.

(2) Annual quantities in metric tons transferred to the following end use applications by end-use, if known:

(i) Food and beverage.

(ii) Industrial and municipal water/wastewater treatment.

(iii) Metal fabrication, including welding and cutting.

(iv) Greenhouse uses for plant growth.

(v) Fumigants (e.g., grain storage) and herbicides.

(vi) Pulp and paper.

(vii) Cleaning and solvent use.

(viii) Fire fighting.

(ix) Transportation and storage of explosives.

(x) Enhanced oil and natural gas recovery.

(xi) Long-term storage (sequestration).

(xii) Research and development.

(b) CO_2 importers and exporters must report the information in paragraphs (a)(1) and (a)(2) at the corporate level.

§ 98.427 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured and transferred CO_2 streams and composition.

(b) The owner or operator of a carbon dioxide production well facility must maintain quarterly records of the mass flow of the extracted and transferred CO_2 stream and composition.

(c) Importers or exporters of CO_2 must retain quarterly records of the mass flow and composition of CO_2 streams imported or exported.

§ 98.428 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

PART 600—[AMENDED]

27. The authority citation for part 600 continues to read as follows:

Authority: 49 U.S.C. 32901–23919q, Pub. L. 109–58.

Subpart A—[Amended]

28. Section 600.006–08 is amended by revising paragraph (c) introductory text and adding paragraph (c)(5) to read as follows:

§ 600.006–08 Data and information requirements for fuel economy vehicles.

* * * * *

(c) The manufacturer shall submit the following data:

* * * * *

(5) Starting with the 2011 model year, the data submitted according to paragraphs (c)(1) through (c)(4) of this section shall include CO_2, N_2O, and CH_4 in addition to fuel economy. Use the procedures specified in 40 CFR part 1065 as needed to measure N_2O and CH_4. Round the test results as follows:

(i) Round CO_2 to the nearest 1 g/mi.

(ii) Round N_2O to the nearest 0.001 g/mi.

(iii) Round CH_4 to the nearest 0.001g/mi.

* * * * *

PART 1033—[AMENDED]

29. The authority citation for part 1033 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

30. Section 1033.205 is amended by revising paragraph (d)(8) to read as follows:

§ 1033.205 Applying for a certificate of conformity.

* * * * *

(d) * * *

(8)(i) All test data you obtained for each test engine or locomotive. As described in § 1033.235, we may allow you to demonstrate compliance based on results from previous emission tests, development tests, or other testing information. Include data for NO_X, PM, HC, CO, and CO_2.

(ii) Starting in the 2011 model year, report measured N_2O and CH_4 as described in § 1033.235. Small manufacturers/remanufacturers may omit this requirement.

* * * * *

31. Section 1033.235 is amended by adding paragraph (i) to read as follows:

§ 1033.235 Emission testing required for certification.

* * * * *

(i) Starting in the 2011 model year, measure N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small manufacturers/remanufacturers may omit this requirement. Use the same units and modal calculations as for your other results to report a single weighted value for CO_2, N_2O, and CH_4. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart J—[Amended]

32. Section 1033.905 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1033.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * * * *

CH_4 methane.

* * * * * * *

N_2O nitrous oxide.

* * * * * * *

PART 1039—[AMENDED]

33. The authority citation for part 1039 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

34. Section 1039.205 is amended by revising paragraph (r) to read as follows:

§ 1039.205 What must I include in my application?

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Starting in the 2011 model year, report measured CO_2 , N_2O, and CH_4 as described in § 1039.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

35. Section 1039.235 is amended by adding paragraph (g) to read as follows:

§ 1039.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart I—[Amended]

36. Section 1039.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1039.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * * * *

CH_4 methane.

* * * * * * *

N_2O nitrous oxide.

* * * * * * *

PART 1042—[AMENDED]

37. The authority citation for part 1042 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

38. Section 1042.205 is amended by revising paragraph (r) to read as follows:

§ 1042.205 Application requirements.

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Starting in the 2011 model year, report measured CO_2, N_2O, and CH_4 as described in § 1042.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

39. Section 1042.235 is amended by adding paragraph (g) to read as follows:

§ 1042.235 Emission testing required for a certificate of conformity.

* * * * *

(g) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart J—[Amended]

40. Section 1042.905 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1042.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * * * *

CH_4 methane.

* * * * * * *

N_2O nitrous oxide.

* * * * * * *

PART 1045—[AMENDED]

41. The authority citation for part 1045 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

42. Section 1045.205 is amended by revising paragraph (q) to read as follows:

§ 1045.205 What must I include in my application?

* * * * *

(q) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Starting in the 2011 model year, report measured CO_2, N_2O, and CH_4 as described in § 1045.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

43. Section 1045.235 is amended by adding paragraph (g) to read as follows:

§ 1045.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

PART 1048—[AMENDED]

44. The authority citation for part 1048 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

45. Section 1048.205 is amended by revising paragraph (s) to read as follows:

§ 1048.205 What must I include in my application?

* * * * *

(s) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Starting in the 2011 model year, report measured CO_2, N_2O, and CH_4 as described in § 1048.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

46. Section 1048.235 is amended by adding paragraph (g) to read as follows:

§ 1048.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. These measurements are not required for measurements using field-testing procedures. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001g/kW-hr.

Subpart I—[Amended]

47. Section 1048.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1048.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * * * *

CH_4 methane.

* * * * * * *

N_2O nitrous oxide.

* * * * * * *

PART 1051—[AMENDED]

48. The authority citation for part 1051 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

49. Section 1051.205 is amended by revising paragraph (p) to read as follows:

§ 1051.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 86 and 1065.

(2) Starting in the 2011 model year, report measured CO_2, N_2O, and CH_4 as described in § 1051.235. Small-volume manufacturers may omit this requirement.

* * * * *

50. Section 1051.235 is amended by adding paragraph (i) to read as follows:

§ 1051.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(i) Starting in the 2011 model year, measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume manufacturers may omit this requirement. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO_2 to the nearest 1 g/kW-hr or 1 g/km, as appropriate.

(2) Round N_2O to the nearest 0.001 g/kW-hr or 0.001 g/km, as appropriate.

(3) Round CH_4 to the nearest 0.001g/kW-hr or 0.001 g/km, as appropriate.

Subpart I—[Amended]

51. Section 1051.805 is amended by adding the abbreviations CH_4 and N_2O in alphanumeric order to read as follows:

§ 1051.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * * * *

CH_4 methane.

* * * * * * *

N_2O nitrous oxide.

* * * * * * *

PART 1054—[AMENDED]

52. The authority citation for part 1054 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

53. Section 1054.205 is amended by revising paragraph (p) to read as follows:

§ 1054.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Starting in the 2011 model year, report measured CO_2, N_2O, and CH_4 as described in § 1054.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

54. Section 1054.235 is amended by adding paragraph (g) to read as follows:

§ 1054.235 What exhaust emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO_2, N_2O, and CH_4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

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

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

(3) Round CH_4 to the nearest 0.001 g/kW-hr.

55. A new part 1064 is added to subchapter U of chapter I to read as follows:

PART 1064—VEHICLE TESTING PROCEDURES

Subpart A—Applicability and general provisions

Subpart B—Air Conditioning Systems

Authority: 42 U.S.C. 7401–7671q.

Subpart A—Applicability and General Provisions

§ 1064.1 Applicability.

(a) This part describes procedures that apply to testing we require for 2011 and later model year light-duty vehicles, light-duty trucks, and medium-duty personal vehicles (see 40 CFR part 86).

(b) See 40 CFR part 86 for measurement procedures related to exhaust and evaporative emissions.

Subpart B—Air Conditioning Systems

§ 1064.201 Method for calculating emissions due to air conditioning leakage.

Determine a refrigerant leakage rate from vehicle-based air conditioning units as described in this section.

(a) *Emission totals.* Calculate an annual rate of refrigerant leakage from an air conditioning system using the following equation:

$$\text{Grams/YR}_{TOT} = \text{Grams/YR}_{RP} + \text{Grams/YR}_{SP} + \text{Grams/YR}_{FH} + \text{Grams/YR}_{MC} + \text{Grams/YR}_{C}$$

Where:

Grams/YR_{RP} = Emission rate for rigid pipe connections as described in paragraph (b) of this section.
Grams/YR_{SP} = Emission rate for service ports and refrigerant control devices as described in paragraph (c) of this section.
Grams/YR_{FH} = Emission rate for flexible hoses as described in paragraph (d) of this section.
Grams/YR_{MC} = Emission rate for heat exchangers, mufflers, receiver/driers, and accumulators as described in paragraph (e) of this section.
Grams/YR_{C} = Emission rate for compressors as described in paragraph (f) of this section.

(b) *Fittings.* Determine the emission rate for rigid pipe connections using the following Equation:

$$\text{Grams/YR}_{RP} = 0.00522 \cdot [(125 \cdot SO) + (75 \cdot SCO) + (50 \cdot MO) + (10 \cdot SW) + (5 \cdot SWO) + (MG)]$$

Where:

SO = The number of single O-ring connections.
SCO = The number of single captured O-ring connections.
MO = The number of multiple O-ring connections.
SW = The number of seal washer connections.
SWO = The number of seal washer with O-ring connections.
MG = The number of metal gasket connections.

(c) *Service ports and refrigerant control devices.* Determine the emission rate for service ports and refrigerant control devices using the following Equation:

$$\text{Grams/YR}_{SP} = (0.3 \cdot HSSP) + (0.2 \cdot LSSP) + (0.2 \cdot STV) + (0.2 \cdot TXV)$$

Where:

HSSP = The number of high side service ports.
LSSP = The number of low side service ports.
STV = The total number of switches, transducers, and expansion valves.
TXV = The number of TXV refrigerant control devices.

(d) *Flexible hoses.* Determine the permeation emission rate for each segment of flexible hose using the following Equation, then add those values to calculate a total emission rate for the system:

$$\text{Grams/YR}_{FH} = 0.00522 \cdot (3.14159 \cdot ID \cdot L \cdot ER)$$

Where:

ID = Inner diameter of hose, in millimeters.
L = Length of hose, in millimeters.
ER = Emission rate per unit internal surface area of the hose, in g/mm^2. Select the appropriate value from the following table:

Material/configuration	ER	
	High-pressure side	Low-pressure side
Rubber	0.0216	0.0144
Standard barrier or veneer hose	0.0054	0.0036
Ultra-low permeation barrier or veneer hose	0.00225	0.00167

(e) *Heat exchangers, mufflers, receiver/driers, and accumulators.* Use an emission rate of 0.5 grams per year as a combined value for all heat exchangers, mufflers, receiver/driers, and accumulators (Grams/YR_{MC}).

(f) *Compressors.* Determine the emission rate for compressors using the following equation:

$$\text{Grams/YR}_{C} = 0.00522 \cdot [(300 \cdot OHS) + (200 \cdot MHS) + (150 \cdot FAP) + (100 \cdot GHS) + (1500/SSL)]$$

Where:

OHS = The number of O-ring housing seals.
MHS = The number of molded housing seals.
FAP = The number of fitting adapter plates.
GHS = The number of gasket housing seals.
SSL = The number of lips on shaft seal (for belt-driven compressors only).

PART 1065—[AMENDED]

56. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

57. A new § 1065.257 is added to subpart C to read as follows:

§ 1065.257 Nondispersive N_2O infrared analyzer.

(a) *Application.* Use a nondispersive infrared (NDIR) analyzer to measure N_2O concentrations in diluted exhaust for batch sampling. Batch sampling may be performed in a single bag covering all phases of the test procedure.

(b) *Component requirements.* We recommend that you use an NDIR analyzer that meets the specifications in Table 1 of § 1065.205. Note that your NDIR-based system must meet the calibration and verification in § 1065.357 and it must also meet the linearity verification in § 1065.307. You may use an NDIR analyzer that has compensation algorithms that are functions of other gaseous measurements and the engine's known or assumed fuel properties. The target value for any compensation algorithm is 0.0 % (that is, no bias high and no bias low), regardless of the uncompensated signal's bias.

(c) *Artifact formation, SO_2, and H_2O removal.* SO_2, NO_X, and H_2O have been shown to react in the sample bag to form N_2O. SO_2 and H_2O must therefore be sequentially removed from the sample gas before the sample enters the bag. SO_2 can be neutralized from the sample gas by passing the sample through a sorbent cartridge packed with 120 cc of a 10:1 ratio of 18–20 mesh sand and $Ca(OH)_2$. This sorbent works only in the presence of H_2O so the H_2O sorbent cartridge must be located downstream of the SO_2 sorbent cartridge. H_2O can be removed by passing the sample through a sorbent cartridge packed with 120 cc of P_2O_5.

58. A new § 1065.357 is added to subpart D to read as follows:

§ 1065.357 CO and Co_2 interference verification for N_2O NDIR analyzers.

(a) *Scope and frequency.* If you measure CO using an NDIR analyzer, verify the amount of CO and Co_2 interference after initial analyzer installation and after major maintenance.

(b) *Measurement principles.* CO and Co_2 can positively interfere with an NDIR analyzer by causing a response similar to N_2O. If the NDIR analyzer uses compensation algorithms that utilize measurements of other gases to meet this interference verification, simultaneously conduct these other measurements to test the compensation algorithms during the analyzer interference verification.

(c) *System requirements.* A N_2O NDIR analyzer must have combined CO and Co_2 interference that is within ±2 percent of the flow-weighted mean concentration of N_2O expected at the standard, though we strongly recommend a lower interference that is within ±1 percent.

(d) *Procedure.* Perform the interference verification as follows:

(1) Start, operate, zero, and span the N_2O NDIR analyzer as you would before an emission test.

(2) Introduce a CO span to the analyzer.

(3) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the transfer line and to account for analyzer response.

(4) While the analyzer measures the sample's concentration, record its output for 30 seconds. Calculate the arithmetic mean of this data.

(5) Scale the CO interference by multiplying this mean value (from paragraph (d)(7) of this section) by the ratio of expected CO to span gas CO concentration. In other words, estimate the flow-weighted mean dry concentration of CO expected during testing, and then divide this value by the concentration of CO in the span gas used for this verification. Then multiply this ratio by the mean value recorded during this verification (from paragraph (d)(7) of this section).

(6) Repeat the steps in paragraphs (d)(2) through (5) of this section, but with a CO_2 analytical gas mixture instead of CO and without humidifying the sample through the distilled water in a sealed vessel.

(7) Add together the CO and CO_2-scaled result of paragraphs (d)(5) and (6) of this section.

(8) The analyzer meets the interference verification if the result of paragraph (d)(7) of this section is within ±2 percent of the flow-weighted mean concentration of N_2O expected at the standard.

(e) *Exceptions.* The following exceptions apply:

(1) You may omit this verification if you can show by engineering analysis that for your N_2O sampling system and your emission calculations procedures, the combined CO, CO_2, and H_2O interference for your N_2O NDIR analyzer always affects your brake-specific N_2O emission results within ±0.5 percent of the applicable N_2O standard.

(2) You may use a N_2O NDIR analyzer that you determine does not meet this verification, as long as you try to correct the problem and the measurement deficiency does not adversely affect your ability to show that engines comply with all applicable emission standards.

Subpart H—[Amended]

59. Section 1065.750 is amended by revising paragraph (a)(1)(ii) and adding paragraph (a)(3)(xi) to read as follows:

§ 1065.750 Analytical gases.

* * * * *

(a) * * *

(1) * * *

(ii) Contamination as specified in the following table:

TABLE 1 OF § 1065.750—GENERAL SPECIFICATIONS FOR PURIFIED GASES

Constituent	Purified synthetic air [1]	Purified N_2 [1]
THC (C_1 equivalent)	<0.05 μmol/mol	<0.05 μmol/mol
CO	<1 μmol/mol	<1 μmol/mol.
CO_2	<10 μmol/mol	<10 μmol/mol.
O_2	0.205 to 0.215 mol/mol	<2 μmol/mol.
NO_X	<0.02 μmol/mol	<0.02 μmol/mol.
N_2O	<0.05 μmol/mol	<0.05 μmol/mol.

[1] We do not require these levels of purity to be NIST-traceable.

* * * * *

(3) * * *

(xi) N_2O, balance purified N_2.

* * * * *

Subpart K—[Amended]

60. Section 1065.1001 is amended by revising the definition for ''Oxides of nitrogen'' to read as follows:

§ 1065.1001 Definitions.

* * * * *

Oxides of nitrogen means NO and NO_2 as measured by the procedures specified in § 1065.270. Oxides of nitrogen are expressed quantitatively as if the NO is in the form of NO_2, such that you use an effective molar mass for all oxides of nitrogen equivalent to that of NO_2.

* * * * *

61. Section 1065.1005 is amended by adding items to the table in paragraph (b) in alphanumeric order to read as follows:

§ 1065.1005 Symbols, abbreviations, acronyms, and units of measure.

* * * * *

(b) * * *

Symbol	Species
* * * * * * *	
$Ca(OH)_2$	calcium hydroxide
* * * * * * *	
P_2O_5	phosphorous pentoxide
* * * * * * *	
SO_2	sulfur dioxide
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