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Part II

Environmental Protection Agency

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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-AO79

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.

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\

\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.

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

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 CO2e 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 CO2e per year, 10,000 metric tons CO2e per year, 25,000 metric tons CO2e per year, and 100,000 metric tons CO2e 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 CO2e per year)	Total number of facilities	Threshold level (metric tons CO2e per year)	Total emissions covered by thresholds \s\ (metric tons CO2e per year)	Total emissions covered by thresholds \s\ Percent	Facilities covered Number	Facilities covered 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

			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.

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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.

\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.

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

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.

Proposed Rule

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.

Sec. 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 CO2e 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 SF6 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 CH4 in amounts equivalent to 25,000 metric tons CO2e or more per year.

(xx) Manure management systems that emit CH4 and N2O in amounts equivalent to 25,000 metric tons CO2e or more per year.

(2) Any facility that emits 25,000 metric tons CO2e 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 Sec. 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 CO2e 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 CO2e per year.

(C) Exporters of industrial greenhouse gases with total bulk exports that exceed 25,000 metric tons CO2e 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 CO2 or a combination of CO2 and other industrial GHGs with total bulk imports that exceed 25,000 metric tons CO2e per year.

(C) Exporters of CO2 or a combination of CO2 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 Sec. 98.6) in metric tons from stationary fuel combustion units, miscellaneous uses of carbonate, and any applicable source category listed in paragraph Sec. 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 Sec. 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 Sec. 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 Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.000

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 Sec. 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 Sec. 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.

Sec. 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 Sec. 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 Sec. 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 Sec. 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 Sec. 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.

Sec. 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 environmental 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

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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.

Sec. 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.

Subpart W--Oil and Natural Gas Systems

Sec. 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.

Sec. 98.231 Reporting threshold.

You must report GHG emissions from oil and natural gas systems if your facility meets the requirements of either Sec. 98.2(a)(1) or (2).

Sec. 98.232 GHGs to report.

(a) You must report CO_2 and CH_4 emissions in metric tons per year from sources specified in Sec. 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.

Sec. 98.233 Calculating GHG emissions.

(a) Estimate emissions using either an annual direct measurement, as specified in Sec. 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 Sec. 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 Sec. 98.234 (d) or (e) to conduct annual leak detection of fugitive emissions from all sources listed in Sec. 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 ASPENTM or AMINECalcTM. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.092

Where:

Es,n = Natural gas fugitive emissions at standard
conditions.
Fs = 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 Fs are not available, follow the method in Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.093

Where:

Es,n = Natural gas fugitive emissions at standard
conditions.
As = 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 Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.094

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 Sec. 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:

[GRAPHIC] [TIFF OMITTED] TP10AP09.095

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 GLYCalcTM. 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 Sec. 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:

[GRAPHIC] [TIFF OMITTED] TP10AP09.096

Where:

$E_{a,i}$ = Annual fugitive emissions from flare stack.
V_a = Volume of natural gas sent to flare stack determined from Sec. 98.234(j)(1).
[eta] = 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 Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.097

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 ([deg]F).
T_a = Temperature at actual emission conditions ([deg]F).
P_s = Absolute pressure at standard conditions (inches of

Hg).
Pa = 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:

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[GRAPHIC] [TIFF OMITTED] TP10AP09.098

Where:

Ea,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 Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.099

Where:

Es,i = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
Es,h = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.
Mi = 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 Sec. 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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.100

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 ([deg]F).
T_a = Temperature at actual emission conditions ([deg]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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.101

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.

[GRAPHIC] [TIFF OMITTED] TP10AP09.102

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.

Sec. 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 Sec. 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 Sec. 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 Sec. 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 Sec. 98.233(e).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in Sec. 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 Sec. 98.233(f).

(3) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in Sec. 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 Sec. 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 Sec. 98.233.

(ii) Calculate annual fugitive emissions from the pump using Equation W-1, by replacing the manufacturer's data on emission (variable Fs) in the Equation with the standard conditions natural gas emission calculated in Sec. 98.234(i)(1)(i).

(iii) Estimate CH4 and CO2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in Sec. 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

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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 As) in the Equation with the standard conditions natural gas emission calculated in Sec. 98.234(i)(2)(i).

(iii) Estimate CH4 and CO2 volumetric and mass emissions from volumetric natural gas fugitive emissions using the calculations in Sec. 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 Sec. 98.234(i)(3)(i).

(iii) Estimate CH4 and CO2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in Sec. 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 Sec. 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.

Sec. 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.

Sec. 98.236 Data reporting requirements.

In addition to the information required by Sec. 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.

Sec. 98.237 Records that must be retained.

In addition to the information required by Sec. 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 Sec. 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.

Sec. 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 NN--Suppliers of Natural Gas and Natural Gas Liquids

Sec. 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.

Sec. 98.401 Reporting threshold.

Any supplier of natural gas and natural gas liquids that meets the requirements of Sec. 98.2(a)(4) must report GHG emissions.

Sec. 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.

Sec. 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 Sec. 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 Sec. 98.404.
[GRAPHIC] [TIFF OMITTED] TP10AP09.179

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.
[GRAPHIC] [TIFF OMITTED] TP10AP09.180

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)

Sec. 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.

Sec. 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.

Sec. 98.406 Data reporting requirements.

(a) In addition to the information required by Sec. 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 Sec. 98.403.

(b) In addition to the information required by Sec. 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 Sec. 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 Sec. 98.403.

Sec. 98.407 Records that must be retained.

In addition to the information required by Sec. 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 Sec. 98.406(b)(4).

(e) Records relating to measured Btu content or carbon content.

Sec. 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
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 CO2 emission value (MT CO2/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