ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2009–0923; FRL–9226–1]

RIN 2060–AP99

Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating a regulation to require monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. This action adds this source category to the list of source categories already required to report greenhouse gas emissions. This action applies to sources with carbon dioxide equivalent emissions above certain threshold levels as described in this regulation. This action does not require control of greenhouse gases.

DATES: The final rule is effective on December 30, 2010. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of December 30, 2010.

ADDRESSES: EPA established a single docket under Docket ID No. EPA–HQ–OAR–2009–0923 for this action. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number: (202) 343–2342; e-mail address: *GHGReportingRule@epa.gov.* For technical information and implementation materials, please go to the Web site *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.* To submit a question, select Rule Help Center, followed by Contact Us.

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to "such other actions as the Administrator may determine"). This final rule affects owners or operators of petroleum and natural gas systems. Regulated categories and entities may include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Source category	NAICS	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211	Extractors of crude petroleum and natural gas.
	211112	Natural gas liquid extraction facilities.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Although Table 1 of this preamble lists the types of facilities of which EPA is aware that could be potentially affected by this action, other types of facilities not listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A as amended by this action. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Many facilities that are affected by the final rule have GHG emissions from multiple source categories listed in 40 CFR part 98. Table 2 of this preamble has been developed as a guide to help potential reporters in the petroleum and natural gas industry affected by this action identify other source categories (by subpart) that they may need to: (1) Consider in their facility applicability determination, and (2) include in their reporting. Table 2 of this preamble identifies the subparts that are likely to be relevant to sources with petroleum and natural gas systems. The table should only be seen as a guide. Additional subparts in 40 CFR part 98 may be relevant for a given reporter. Similarly, not all listed subparts are relevant for all reporters.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS

Source category	Other subparts recommended for review to determine applicability
Petroleum and Natural Gas Systems.	40 CFR part 98, subpart C: General Stationary Fuel Combustion Sources.
	40 CFR part 98, subpart Y: Petroleum Refineries.
	40 CFR part 98, subpart MM: Suppliers of Petroleum Products.
	40 CFR part 98, subpart NN: Suppliers of Natural Gas and Natural Gas Liquids.
	40 CFR part 98, subpart PP: Suppliers of Carbon Dioxide
	40 CFR part 98, subpart RR: Injection and Geologic Sequestration of Carbon Dioxide (proposed).

What is the effective date? The final rule is effective on December 30, 2010. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. EPA is issuing this final rule under section 307(d)(1) of the Clean Air Act, which states: "The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies." Thus, section 553(d) of the APA does not apply to this rule. EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making this rule effective on December 30, 2010. Section 5 U.S.C. 553(d)(3) allows an effective date less than 30 days after publication "as otherwise provided by the agency for good cause found and published with the rule." As explained below, EPA finds that there is good cause for this rule to become effective on or before December 31, 2010, even if this results in an effective date fewer than 30 days from date of publication in the **Federal Register.**

While this action is being signed prior to December 1, 2010, there is likely to be a significant delay in the publication of this rule as it contains complex diagrams, equations, and charts, and is relatively long in length. As an example, EPA signed a shorter technical amendments package related to the same underlying reporting rule on October 7, 2010, and it was not published until October 28, 2010, 75 FR 66434, three weeks later.

The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Where, as here, the final rule will be signed and made available on the EPA Web site more than 30 days before the effective date, but where the publication is likely to be delayed due to the complexity and length of the rule, that purpose is still met. Moreover, for specified emission sources for certain industry segments, EPA has made available the optional use of best available monitoring methods (BAMM) during the 2011 calendar year. For these circumstances, facilities covered by this rule may use BAMM for any parameter for which it is not reasonably feasible to acquire, install, or operate a required piece of monitoring equipment in a facility, or to procure measurement services from necessary providers. This will provide facilities a substantial additional period to adjust their behavior to the requirements of the final rule. Accordingly, we find good cause exists to make this rule effective on or before December 31, 2010, consistent with the purposes of 5 U.S.C. 553(d)(3).[1]

Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by January 31, 2011. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

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

AAPG American Association of Petroleum Geologists
AGA American Gas Association
AGR Acid gas removal
ANSI American National Standards Institute
API American Petroleum Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
BLS Bureau of Labor Statistics
BOEMRE Bureau of Ocean Energy Management, Regulation and Enforcement
CAA Clean Air Act
CBI Confidential business information
CBM Coal bed methane
CEMS Continuous emission monitoring systems
cf cubic feet
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
DOE Department of Energy
E&P exploration and production
EIA Economic Impact Analysis
EO Executive Order
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
ESD emergency shutdown
FPSO floating production and storage offloading
FR **Federal Register**
GHG greenhouse gas
GOR gas to oil ratio
GRI Gas Research Institute
GWP global warming potential
HHV high heat value
IBR incorporation by reference
ICR information collection request
IPCC Intergovernmental Panel on Climate Change
IR infrared
ISO International Organization for Standardization
kg kilograms
LACT lease automatic custody transfer
LDCs local natural gas distribution companies
LNG liquefied natural gas
LPG liquefied petroleum gas
M&R meters and regulators
mmBtu million British thermal units
MMS Minerals Management Service
MMscfd million standard cubic feet per day
$MMTCO_2e$ million metric tons carbon dioxide equivalent
MRR mandatory GHG reporting rule
N_2O nitrous oxide
NAESB North American Energy Standards Board
NAICS North American Industry Classification System
NGLs natural gas liquids
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality, Planning and Standards
OMB Office of Management and Budget
OVA organic vapor analyzer
ppm parts per million
QA quality assurance
QA/QC quality assurance/quality control
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
SBA Small Business Administration
SBREFA Small Business Regulatory Enforcement and Fairness Act
SSM startup, shutdown, and malfunction
STP standard temperature and pressure
TCR The Climate Registry
TSD technical support document
TVA toxic vapor analyzer

[1] We recognize that this rule could be published at least 30 days before December 31, 2010, which would negate the need for this good cause finding, and we plan to request expedited publication of this rule in order to decrease the likelihood of a printing delay. However, as we cannot know the date of publication in advance of signing this rule, we are proceeding with this good cause finding for an effective date on or before December 31, 2010.

U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
U.S.C. United States Code
USGS United States Geologic Society
VOC volatile organic compound(s)
WCI Western Climate Initiative

Table of Contents

I. Background

A. Organization of This Preamble

This preamble consists of four sections. The first section provides a brief history of 40 CFR part 98 and describes the purpose and legal authority for this action.

The second section of this preamble summarizes the revisions made to the general provisions in 40 CFR part 98, subpart A and outlines the specific requirements for subpart W being incorporated into 40 CFR part 98 by this action. It also describes the major changes made to this source category since proposal and provides a brief summary of significant public comments and EPA's responses on issues specific to each industry segment. Additional responses to significant comments can be found in the document Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems.

The third section of this preamble provides the summary of the cost impacts, economic impacts, and benefits of the final rule and discusses comments on the economic impact analyses for subpart W.

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

B. Background on the Final Rule

This action finalizes monitoring and reporting requirements for petroleum and natural gas systems.

On April 12, 2010, EPA proposed subpart W—Petroleum and Natural Gas Systems, amending 40 CFR part 98 (*i.e.,* the regulatory requirements for the Greenhouse Gas Reporting Program). The GHG Reporting Program requires reporting of GHG emissions and other relevant information from certain source categories in the United States. The GHG Reporting Program, which became effective on December 29, 2009, includes reporting requirements for facilities and suppliers in 32 source categories. EPA established this program in response to the fiscal year 2008 Consolidated Appropriations Act.[2] This Act authorized funding for EPA to develop and publish a rule "* * * to require the mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States." An accompanying joint explanatory statement directed EPA to "use its existing authority under the Clean Air Act" to develop a mandatory GHG reporting rule. For more detailed background information on the GHG Reporting Program, see the preamble to the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009).

[2] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG reporting rule, and provided additional funding in the 2009 and 2010 Appropriations Acts (Consolidated Appropriations Act, 2009, Pub. L. 110–329, 122 Stat. 3574–3716 and Consolidated Appropriations Act, 2010, Pub. L. 111–117, Stat. 3034–3408).

This final action adds requirements for facilities that contain petroleum and natural gas systems to report equipment leaks and vented GHG emissions (subpart W) to the GHG Reporting Program. The rule applies to facilities in specific segments of the petroleum and natural gas industry that emit GHGs greater than or equal to 25,000 metric tons of CO_2 equivalent per year. These data will inform EPA's implementation of CAA section 103(g) regarding improvements in sector based non-regulatory strategies and technologies for preventing or reducing air pollutants, and inform policy on possible regulatory actions to address GHG emissions. As stated earlier in this section, this rule was proposed by EPA on April 12, 2010. One public hearing was held in April 2010, and the 60-day public comment period ended June 11, 2010.

C. Legal Authority

EPA is promulgating 40 CFR part 98, subpart W under the existing CAA authorities provided in CAA section 114. As discussed in detail in Sections I.C and II.Q of the preamble to the 2009 final rule (74 FR 56260), CAA section 114(a)(1) provides EPA with broad authority to require emissions sources, persons subject to the CAA, manufacturers of process or control equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information as the Administrator requests for the purposes of carrying out any provision of the CAA. EPA may gather information for a variety of purposes, including for the purpose of assisting in the development of emissions reduction regulations in the petroleum and natural gas industry, determining compliance with implementation plans or standards, or more broadly for "carrying out any provision" of the CAA. Section 103 of the CAA authorizes EPA to establish a national research and development program, including non-regulatory approaches and technologies, for the prevention and control of air pollution, including GHGs. As discussed in the petroleum and natural gas systems proposal (75 FR 18608, April 12, 2010), among other things, data from petroleum and natural gas systems will inform decisions about possible emissions reduction regulations in the petroleum and natural gas industry. The data collected will also inform EPA's implementation of CAA section 103(g) regarding improvements in sector-based non-regulatory strategies and technologies for preventing or reducing air pollutants.

EPA has the authority under the CAA to collect emissions information from offshore petroleum and natural gas platforms including those located in areas of the Central and Western Gulf of Mexico as identified in CAA section 328(b). This final action does not regulate GHG emissions; rather it gathers information to inform EPA's evaluation of various CAA provisions. Moreover, EPA's authority under CAA section 114 is broad, and extends to any person "who the Administrator believes may have information necessary for the purposes" of carrying out the CAA, even if that person is not subject to the CAA. Indeed, by specifically authorizing EPA to collect information from both persons subject to any requirement of the CAA, as well as any person who the Administrator believes may have necessary information, Congress clearly intended that EPA could gather information from a person not otherwise subject to CAA requirements. EPA is comprehensively considering how to address climate change under the CAA, including both regulatory and non-regulatory options. The information from offshore platforms will inform our analyses, including options applicable to emissions of any offshore platforms that EPA is authorized to regulate under the CAA.

II. Reporting Requirements for Petroleum and Natural Gas Systems

A. Overview of Greenhouse Gas Reporting Program

The GHG Reporting Program requires reporting of GHG emissions and other relevant information from certain source categories in the United States, as discussed in Section I.B. of this preamble. The rule requires annual reporting of GHGs including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and other fluorinated compounds (*e.g.,* hydrofluoroethers (HFEs)).

The GHG Reporting Program requires that source categories subject to 40 CFR part 98 monitor and report GHGs in accordance with the methods specified in the individual subparts. For a list of the specific GHGs to be reported and the GHG calculation procedures, monitoring, missing data procedures, recordkeeping, and reporting required by facilities subject to subpart W included in this action, see Section II.D of this preamble.

B. Overview of Confidentiality Determination for Data Elements in the Greenhouse Gas Reporting Program

This final rule does not address whether data reported under subpart W will be released to the public or will be treated as confidential business information. EPA published a proposed rule and confidentiality determination on July 7, 2010 (75 FR 39094) that addressed this issue. In that action, EPA proposed which specific data elements would be released to the public and which would be treated as confidential business information. EPA received comments on the proposal, and is in the process of considering these comments. A final rule and determination will be issued before any data are released, and the final determination will include all of the data elements under subpart W.

C. Summary of Changes to the General Provisions of the Greenhouse Gas Reporting Program

This final action amends certain requirements in 40 CFR part 98, subpart A (General Provisions). These amendments are summarized in this section of the preamble.

Changes to Applicability. In this final action, EPA is amending Table A–4 of subpart A, referenced in 40 CFR 98.2(a)(2), to add the petroleum and natural gas systems source category. In addition, EPA is amending 40 CFR 98.2(a) so that 40 CFR part 98 applies to facilities located in the United States and on or under the Outer Continental Shelf. This revision is necessary to ensure that any petroleum or natural gas platforms located on or under the Outer Continental Shelf of the United States are required to report under 40 CFR part 98, subpart W.

Changes to Definitions. In this final action, EPA is also amending 40 CFR 98.6 (definitions). EPA is revising the definition of United States as applied under part 98 to clarify that it includes the territorial seas. Other facilities located offshore of the United States covered by the GHG Reporting Program at 40 CFR part 98 may also be affected by this change in the definition of United States. In addition to the change to the definition of United States, EPA has amended 40 CFR 98.6 by adding a definition of "Outer Continental Shelf." This definition is drawn from the definition in the U.S. Code and the Clean Air Act, 328(a)(4)(A). These revisions are necessary to ensure that facilities on land, in the territorial seas, or on or under the Outer Continental Shelf, as defined in 43 U.S.C. 1331, and that otherwise meet the applicability criteria of the rule are required to report.

Incorporation by Reference (IBR). In the April 2010 proposal, EPA proposed to amend 40 CFR 98.7 by including the following standard methods: GRI GlyCalc software, the E&P Tank software, and the American Association of Petroleum Geologist (AAPG) Geologic Provinces Code Map. EPA has revised the listing of proposed methods for incorporation by reference. Hence, in this final action EPA is finalizing amendments to 40 CFR 98.7 (incorporation by reference) to include standard methods referenced in 40 CFR part 98, subpart W. Those include: American Association of Petroleum Geologists Geologic Provinces Code Map including the Alaska Geological Province Boundary Map; and the Energy Information Administration Oil and Gas Field Code Master List.

D. Summary of the Requirements for Petroleum and Natural Gas Systems (Subpart W)

1. Summary of the Final Rule

Source Category Definition. This source category consists of the following segments of the petroleum and natural gas systems source category:

- *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure, and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and, exploration that is not conducted on production platforms.
- *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well pad or associated with a well pad (including compressors, generators, or storage facilities), and portable non-self-propelled equipment on a well pad or associated with a well pad (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2, and all petroleum and natural gas production located on islands, artificial islands, or structures connected by a causeway to land, an island, or artificial island.

• *Onshore natural gas processing.* Natural gas processing means facilities that separate and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes: (1) all processing facilities that fractionate and (2) those that do not fractionate with throughput of 25 MMscf per day or greater.

• *Onshore natural gas transmission compression.* Onshore natural gas transmission compression includes any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include reporting of emissions from gathering lines and boosting stations—these sources are currently not covered by subpart W.

• *Underground natural gas storage.* Underground natural gas storage includes subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject natural gas into and remove natural gas from the underground reservoirs.

• *Liquefied natural gas (LNG) storage.* LNG storage includes onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

• *LNG import and export facilities.* LNG import equipment includes all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

• *Natural gas distribution.* Natural gas distribution includes the distribution pipelines (not interstate transmission pipelines or intrastate transmission pipelines) and metering and regulating equipment at city gate stations, and excluding customer meters, that physically deliver natural gas to end users and is operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment excludes customer meters and infrastructure and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and "farm taps" upstream of the local distribution company inlet—these sources are not covered by subpart W.

Facilities from the following segments: (1) Offshore petroleum and natural gas production, (2) onshore natural gas processing, (3) onshore natural gas transmission compression, (4) underground natural gas storage, (5) LNG storage, and (6) LNG import and export equipment, that meet the applicability criteria in the General Provisions (40 CFR 98.2(a)(2)) and summarized in Section II.C of this preamble must report GHG emissions. Facilities assessing their applicability in the onshore petroleum and natural gas production segment (as defined in 40 CFR 98.238), must include only emissions from equipment, as specified in 40 CFR 98.232(c) to determine if they exceed the 25,000 metric ton CO_2e threshold and thus are required to report their GHG emissions. Facilities assessing their applicability in the onshore natural gas distribution industry segment (as defined in 40 CFR 98.238), must include only emissions from equipment as specified 40 CFR 98.232(i) to determine if they exceed the 25,000 metric ton CO_2e threshold and thus are required to report their GHG emissions. For other segments, facilities must assess applicability based on all source categories for which methods are provided in the GHG Reporting Program.

GHGs to Report. Facilities must report:

• Carbon dioxide (CO_2) and methane (CH_4) emissions from equipment leaks and vents.

• CO_2, CH_4, and nitrous oxide (N_2O) from combustion.

• CO_2, CH_4, and nitrous oxide (N_2O) emissions from combustion at flares.

Reporting Threshold. Facilities that contain petroleum and natural gas systems that meet the requirements of 40 CFR 98.2(a)(2) are to report GHG emissions under subpart W. For applying the threshold defined in 40 CFR 98.2(a)(2), an onshore petroleum and natural gas production facility will consider emissions only from equipment specified in 40 CFR 98.232(c). For applying the threshold defined in 40 CFR 98.2(a)(2), a natural gas distribution facility shall consider emissions only from equipment specified in 40 CFR 98.232(i).

GHG Emissions Calculation and Monitoring. The petroleum and natural gas source category consists of several segments (*e.g.,* onshore petroleum and natural gas production, natural gas processing). Within those segments, there are different types of emissions sources, some of which appear in multiple segments (*e.g.,* pneumatic devices, blowdown vents, *etc.*). Subpart W provides methodologies for calculating emissions from each source type. Although the rule, in some cases, allows reporters the flexibility to choose from more than one method for calculating emissions from a specific source type, reporters must keep record in their monitoring plans as outlined in 40 CFR 98.3(g) of this chapter. Table 3 of this preamble summarizes those source types and indicates their applicable segments. Reporters of an industry segment as defined by 40 CFR 98.230 would report emissions under subpart W only from the corresponding source types listed for that particular industry segment as defined in 40 CFR 98.232. For example, an onshore natural gas transmission compression reporter as defined by 40 CFR 98.230(a)(4) would report emissions under subpart W only for sources defined in 40 CFR 98.232(e). The text following the table summarizes the different methodologies reporters must use to monitor and calculate their GHG emissions from each emissions source.

It is important to note, as detailed in Section II.F of this preamble, that for specified time periods during the 2011 data collection year, reporters may use best available monitoring methods for certain emissions sources in lieu of the methods prescribed for specific sources below. This is intended to give reporters flexibility as they revise procedures and contractual arrangements during early implementation of the rule.

TABLE 3—SUMMARY OF SOURCE TYPES IN EACH INDUSTRY SEGMENT

Source type	Offshore production	Onshore production	Natural gas processing	Natural gas transmission compression	Underground storage	LNG Storage	LNG Import and export equipment	Distribution
Natural gas pneumatic device venting		X		X	X			
Natural gas driven pneumatic pump venting		X						
Acid gas removal vent stack		X	X					
Dehydrator vent stacks		X	X					
Well venting for liquids unloading		X						
Gas well venting during well completions and workovers with hydraulic fracturing		X						
Gas well venting during well completions and workovers without hydraulic fracturing		X						
Blowdown vent stacks		X	X	X			X	
Onshore production storage tanks		X						
Transmission storage tanks				X				
Well testing venting and flaring		X						
Associated gas venting and flaring		X						
Flare stacks		X	X					
Centrifugal compressor venting		X	X	X	X	X	X	
Reciprocating compressor rod packing venting		X	X	X	X	X	X	
Other emissions from equipment leaks		X	X	X	X	X	X	X
Population Count and Emissions Factor		X			X	X	X	X
Vented, Equipment Leaks and Flare Emissions Identified in BOEMRE GOADS Study	X							
Enhanced Oil Recovery hydrocarbon liquids dissolved CO_2		X						
Enhanced Oil Recovery injection pump blowdown		X						
Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions		X						X

2. Summary of Methodologies for Each Source Type in Table 3 of this preamble.

• *Natural gas pneumatic device venting:* Calculate CO_2 and CH_4 emissions from natural gas pneumatic devices using component count for each type (*i.e.,* continuous high bleed, continuous low bleed, and intermittent bleed) together with a population emission factor for each type from Tables W–1A, W–3, and W–4 of subpart W. Onshore petroleum and natural gas production reporters must complete a total count of pneumatic devices any time within the first three calendar years. A reporter must report pneumatic device emissions annually. For any years where activity data (count of pneumatic devices) is incomplete, use best available data or engineering estimates to calculate pneumatic device emissions.

• *Natural gas driven pneumatic pump venting:* Calculate CO_2 and CH_4 emissions using component count of natural gas pneumatic pumps together with a population emission factor from Table W–1A of subpart W.

• *Acid gas removal (AGR) vents:* Calculate CO_2 emissions using one of the following calculation methodologies:

—Use CEMS as specified under subpart C of this section. If CEMS is not operated or maintained, a CEMS may be installed.
—Use metered flow and volume weighted CO_2 content of the vent stack gas. The approaches available to measure the volume weighted CO_2 content include using a continuous gas analyzer or sampling the gas quarterly.
—Use metered flow of the inlet natural gas and volume weighted CO_2 content of the natural gas flowing into and out of the AGR unit. The approaches available to measure the volume weighted CO_2 content include using a continuous gas analyzer or sampling the gas quarterly.
—Use a process simulator that uses the Peng-Robinson equation of state and speciates CO_2 emissions.

• *Dehydrator vents.* Calculate CH_4 and CO_2 emissions using the following calculation methodologies:

—For glycol dehydrators with a throughput greater than or equal to 0.4 million standard cubic feet per day, use a software program such as GRI GlyCalc or AspenTech HYSYS® for example, to calculate emissions. The software program must determine the equilibrium coefficient using the Peng-Robinson equation of state, speciates CH_4 and CO_2 emissions from dehydrators, and have provisions to include regenerator control devices, a separator flash tank, stripping gas, and gas injection pump or gas assist pump.
—For glycol dehydrators with a throughput less than 0.4 million standard cubic feet per day, use daily flow rate of wet natural gas together with an emission factor to calculate CO_2 and CH_4 emissions. There are separate emission factors for dehydrator units with a gas assist pump.
—For desiccant dehydrators, calculate the amount of gas vented from the vessel every time it is depressurized for desiccant replacement. This involves knowing the dimensions of the dehydrator and percent of the vessel that is packed with desiccant, and the time between desiccant refilling.

• *Well venting for liquids unloading:* Calculate CO_2 and CH_4 emissions using either of the following calculation methodologies (the same methodology must be used for the entire duration of the calendar year).

—Determine the average gas flow for the duration of the liquids unloading using a meter on the vent line. A new average flow rate must be calculated every other year starting in the first calendar year of reporting. Use the total venting time during the year together with the gas flow rate to determine the gas vented during liquid unloading.
—Determine the casing dimension, the shut-in pressure, sales flow rate and hours that the well was left open to the atmosphere to calculate the volume of gas emitted during liquid unloading.

• *Gas well venting during well completions and workovers from hydraulic fracturing:* Calculate CO_2 and CH_4 emissions using the cumulative vent time during the year and the flow rate of gas vented, separately for both completions and workovers. Use either of the following methodologies to determine the flow rate of the gas.

—Determine the flow rate of vented gas from one well during a well completion, and also one well workover event, using a meter installed on the vent line. A flow rate determined from a well during a well completion can be applied to all wells in the same field that undergo a completion. A flow rate determined from a well during a well workover can be applied to all wells in the same field that undergo a workover. A field-level emissions factor must be developed every 2 years starting in the first calendar year of reporting.

—Measure the pressure before and after the well choke for both one well during a well completion, and also one well workover event. A flow rate determined from a well during a well completion can be applied to all wells in the same field that undergo a completion. A flow rate determined from a well during a well workover can be applied to all wells in the same field that undergo a workover. The flow rate must be determined in the first year of every 2-year period. Separate equations are provided for sonic and sub-sonic flow.

• *Gas well venting during well completions and workovers without hydraulic fracturing:* Calculate CO_2 and CH_4 emissions using the cumulative vent time during the year and average daily gas production for each well.

• *Blowdown vent stacks.* Calculate CH_4 and CO_2 emissions from blowdown vent stacks by calculating the total volume of equipment and vessels blown down between isolation valves. This includes the volume of all piping, compressor cases or cylinders, manifolds, suction and discharge bottles or any other gas-containing volume contained between the isolation valves. Total physical volume of less than 50 cubic feet between isolation valves of process vessels, piping, and equipment do not have to be reported. The total volume contained between isolation valves, which can be determined using an engineering equation based on best available data, for each process vessel and the number of times it was blowndown in the calendar year equals the actual volume of emissions, which are then converted to GHG volumes at standard conditions and GHG emissions using the concentration of CH_4 and CO_2 in the applicable stream. Reporters may use the same calculated volumes in subsequent years if the hardware has not changed. For process vessels blowndown to a flare, calculate the volume of emissions the same as if they were not flared, then use that volume as an input parameter in the flare stacks section to estimate combustion emissions.

• *Onshore production storage tanks:* Calculate CH_4 and CO_2 emissions using one of the following calculation methodologies:

—For tanks with separator throughput greater than or equal to 10 barrels per day, use a software program, such as AspenTECH® or API 4697 E&P Tank for example, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions from tanks. The low pressure separator oil composition and Reid vapor pressure can be determined using the default values within the software program, or using a representative sample analysis.

—Alternatively, for tanks with separator throughput greater than or equal to 10 barrels per day, you may assume all of the CH_4 and CO_2 in the low pressure separator oil is emitted. The low pressure separator oil composition shall be determined using an appropriate sample analysis, or default oil compositions in software programs.

—For wells with oil production greater than or equal to 10 barrels per day that flow directly to a tank without going through a separator, calculate emissions by using an appropriate sample analysis and assuming all of the CH_4 and CO_2 are emitted.

—For separator throughput or wells flowing directly to tanks with throughput less than 10 barrels per day, use a population emission factor together with the flow rate.

—Account for occurrences when the separator dump valve is improperly open and bypassing gas to the tank through the liquid, by determining the number of hours the dump valve is open and scaling the emissions upwards using the correction factor. The number of hours the dump valve is open can be determined using the maintenance or operations records as follows: (1) Assume that if a dump valve is found open, that it was open from either the beginning of the calendar year, or since the most recent maintenance or operations record confirming proper closure of the dump valve and (2) Assume that a dump valve is improperly open until there is a maintenance or operations record showing that the dump valve is closed or to the end of the calendar year.

• *Transmission storage tanks.* For transmission storage tanks, once per calendar year reporters must monitor the tank vapor vent stack using an optical gas imaging instrument, to view the emissions for 5 minutes. Alternatively, the scrubber dump valves can be monitored with an acoustic leak detector. If the vent stack emits continuously over that time period, then the reporter must use either a meter or an acoustic leak detection device to measure the flow rate of the vent to determine emissions. This will quantify tank emissions resulting from malfunctioning scrubber dump valves. If a tank is vented to a flare, then use the onshore petroleum and natural gas production storage tanks methodology option 1 (simulation) to estimate the volume and composition of vapors flared. Then use the flare stacks methodology to estimate the emissions.

• *Well testing venting and flaring.* Calculate CH_4, CO_2, and N_2O emissions from well testing venting and flaring by multiplying available data from production records on the gas-to-oil ratio for produced hydrocarbon liquids, by the flow rate (in barrels of oil per day) of the well being tested, by the number of days in the calendar year the well is tested. If gas-to-oil ratios are not available, use a sample analysis to determine gas-to-oil ratios. For the calculated testing gas volume that is flared, use the method set forth for flare stacks to estimate the emissions.

• *Associated gas venting and flaring.* Calculate CH_4, CO_2, and N_2O emissions from associated gas venting and flaring by multiplying available data from production records on the gas-to-oil ratio for produced hydrocarbon liquids, by the volume of liquids produced in the calendar year. The gas-to-oil ratios can be determined by the use of a representative gas-to-oil ratio of wells in the same field. If gas-to-oil ratios are not readily available, use a sample analysis to determine gas-oil ratios. For the calculated associated gas volume that is flared, use the method set forth for flare stacks to estimate the emissions.

• *Flare stacks.* Calculate CH_4, CO_2, and N_2O emissions from flare stacks by metering or using engineering estimation to determine the volume of gas sent to the flare, and the gas composition to then estimate the portion that is combusted and the portion that is not combusted, using the flare efficiency. Where methodologies for other sources in subpart W refer to this methodology in order to estimate flaring emissions, use the estimated volume of flared gas from those sources as the gas to flare volume in this methodology, and report those emissions under those sources. Calculate N_2O from flare stacks using the methodology set forth for in 40 CFR 98.233(z).

• *Centrifugal compressor venting.*

—Calculate CH_4 and CO_2 emissions from wet seal oil degassing vents in onshore petroleum and natural gas production by counting the total population of centrifugal compressors and multiplying it by the appropriate emission factors.

—Calculate CH_4 and CO_2 emissions from wet seal and dry seal centrifugal compressor blowdown vents, wet seal degassing, and unit isolation valves for wet seal and dry seal compressors (see Table 4 of this preamble) found in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment by:

—Measuring venting from blowdown vents when the compressor is found in the operating mode using a meter.

– Measuring wet seal degassing venting when the compressor is found in the operating mode using a meter.

—Measuring venting from unit isolation valves when the compressor is found in not operating, depressurized mode using a meter. If these sources are vented through a common manifold, you must measure each vent source separately. Determine average emissions from each mode of operation by summing the emissions from each source in each mode and dividing it by the total population measured. The result will be an emission factor per compressor per hour for each mode of operation. Multiply each emission factor by the total number of compressor-hours in each mode of operation. Reporters are not required to shutdown compressors to conduct measurements. The owner or operator must schedule an annual measurement of each compressor and the owner or operator can take the measurement in the mode in which the compressor is found during the annual measurement. However, the owner or operator must conduct a measurement of each compressor in the not operating, depressurized mode at least once every three calendar years. Please see Compressor Modes and Threshold, Docket EPA–HQ–OAR–2009–0923.

TABLE 4—SUMMARY OF EMISSION FACTOR CATEGORIES FOR CENTRIFUGAL COMPRESSOR VENTING

Component	Operating mode	
	Operating	Not operating—depressurized
Blowdown Vent	Individual Factor	Not Applicable.
Wet Seal Oil Degassing Vent	Individual Factor	Not Applicable.
Unit Isolation Valve	Not Applicable	Individual Factor.

• *Reciprocating compressor rod packing venting.* Calculate CH_4 and CO_2 emissions from reciprocating compressor rod packing venting in onshore petroleum and natural gas production by counting the total population of reciprocating compressors and multiplying it by the emission factors provided in 40 CFR 98.233(p)(10). Calculate CH_4 and CO_2 emissions for reciprocating compressor blowdown valves, rod packing, and unit isolation valves (*see* Table 5 of this preamble) from onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment by:

—Measuring venting from blowdown vents when the compressor is found in operating and standby pressurized modes using a meter.

—Measuring rod packing vents when the compressor is found in operating and standby pressurized modes using a meter. If there is not a vent line, a rigorous approach of scanning for all potential leakage paths for the gas must be used and quantified with a meter, high volume sampler, or calibrated bag as appropriate.

—Measuring venting from unit isolation valves using a meter when the compressor is found in not operating, depressurized mode. For through-valve leakage to open ended vents, such as unit isolation valves on not operating depressurized compressors, acoustic leak detection devices may also be used.

If these sources are vented through a common manifold, you must measure each vent source separately. Determine average emissions from each mode of operation by summing the emissions from each source in each mode and dividing it by the total population measured. The result will be an emission factor per compressor per hour for each mode of operation. Multiply each emission factor by the total number of compressor-hours in each mode of operation. Reporters are not required to shut down compressors to conduct measurements. The owner or operator must conduct a measurement of each compressor, and measure the compressor in the mode as it is found during the annual measurement. However, the owner or operator must conduct at least one measurement of each compressor in the not operating, depressurized mode at least one time every 3 calendar years. Please see “Compressor Modes and Threshold” Docket EPA–HQ–OAR–2009–0923.

TABLE 5—SUMMARY OF EMISSION FACTOR CATEGORIES FOR RECIPROCATING COMPRESSOR VENTING

Component	Operating mode		
	Operating	Standby pressurized	Not operating—depressurized
Blowdown Vent	Use measurements in either mode to develop combined factor.		Not Applicable.
Rod Packing Seals	Individual Factor	Individual Factor	Not Applicable.
Unit Isolation Valve	Not Applicable	Not Applicable	Individual Factor.

• *Leak detection and leaker factors* (onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import export, natural gas distribution). Perform a leak detection survey using one of the three following methods:

—Use an optical gas imaging instrument. The method must be used for all sources that cannot be monitored without elevating personnel more than 2 meters above a support surface.

—Use an infrared laser beam illuminated instrument.

—Use Method 21.

—Multiply the count of each type of leaking component by the appropriate leaker factors in Tables W–2, W–3, W–4, W–5, W–6, and W–7 of subpart W. Tubing systems less than 0.5 inch are exempt from reporting.

—For natural gas distribution, leak detection is required only for above ground metering and regulating stations (also called “gate stations”) at which custody transfer occurs. The leak detection and monitoring requirements prescribed in subpart W do not include customer meters. All facilities under this source must conduct at least one leak survey each calendar year. Multiple leak surveys may be conducted in order to account for leak repairs. If multiple surveys are chosen by the owner or operator and performed, each survey must be facility wide.

—If only one leak survey is conducted in the calendar year, assume that all leaks found emit for the entire year.

—If multiple leak surveys are conducted, assume that each leak that is found has been emitting since the last survey; or since the beginning of the calendar year. Assume that each leak found during the last leak survey in a calendar year continues to emit until the end of the calendar year.

• *Population count and emission factor.* Calculate CH_4 and CO_2 emissions from the sources listed in 40 CFR 98.233(r).

—For onshore petroleum and natural gas production, each component must either be counted individually; or major equipment pieces must be counted and then the appropriate average component counts should be applied using Tables W–1B, W–1C, and W–1D of subpart W. The most recent gas composition that is representative of the field must be used to determine the percent of the leaked gas that is CH_4 and CO_2.

—For underground natural gas storage, the emission factors in Table W–4 of subpart W must be applied to population counts of components on storage wellheads.

—For LNG storage, the emission factor for vapor recovery compressors, must be applied to the total population count.

—For LNG import and export equipment, the emission factor for vapor recovery compressors must be applied to the total population count.

—For natural gas distribution, all emissions from above ground custody transfer metering and regulating stations as determined by leak detection surveys must be totaled and then divided by the total number of surveyed meter runs to develop an average emission factor for above grade metering and regulating stations. This average emission factor will be multiplied by the total number of above ground metering and regulating stations meter runs at which custody transfer does not occur to estimate emissions from those stations. Emission factors in Table W–7 of subpart W will be used to account for equipment leaks in underground meter and regulation stations, pipelines, and service lines.

• *Offshore production.* Calculate CO_2 and CH_4 emissions from offshore petroleum and natural gas production facilities using the methods outlined by BOEMRE [3] Gulfwide Emissions Inventory Study, herein after referred to as "GOADS." Offshore production facilities are not required to report portable emissions to EPA.

—Offshore production facilities reporting under the BOEMRE GOADS program must report where available the same annual emissions as calculated by BOEMRE using activity data submitted by platform operators in the latest GOADS study calculated by BOEMRE's data base management system. For the 2011 calendar year, offshore production facilities currently under the GOADS program must report the latest published emissions from the GOADS study for platforms in service in the GOADS study year. In subsequent calendar years when BOEMRE publishes an updated GOADS study, reporters shall report emissions based on that latest GOADS study. For each calendar year that does not overlap with the GOADS publication of a new study, reports for platforms operating in the current year that were also operating in the last published GOADS study should be adjusted based on the operating time for each platform relative to the operating time in the previous reporting period.

—For offshore production facilities that do not report under the BOEMRE GOADS program (non-GOADS reporters), monthly activity data from applicable offshore production facilities must be collected for the first calendar year in accordance with the latest GOADS program instructions. Calculation of GHG emissions must be performed using the latest GOADS program emission factors and methodologies as outlined in the latest published GOADS study. In subsequent calendar years, facilities not under GOADS jurisdiction must follow the data collection cycle as required in the GOADS program by collecting new monthly activity data, estimating GHG emissions using the latest GOADS program emission factors and methodologies and report those emissions to EPA. For each calendar year that does not overlap with a new GOADS study publication, offshore production facilities not reporting under the BOEMRE GOADS program must report the last reported emissions data with emissions adjusted based on the operating time for each platform relative to operating time in the previous reporting period. Thus, these facilities will gather data and estimate updated emissions on the same cycle as facilities reporting to the GOADS program.

—For either first or subsequent year reporting, platforms either within or outside of GOADS jurisdiction that were not covered in the previous GOADS data collection cycle shall collect monthly activity data from platform sources in accordance with the latest GOADS program instructions and calculate GHG emissions using the latest GOADS program emission factors and methodologies.

—If BOEMRE discontinues or delays their GOADS survey by more than 4 years, then offshore production facilities shall collect monthly activity data every 4 years from platform sources in accordance with the latest published version of the GOADS program instructions, and annual GHG emissions shall be calculated using latest GOADS program emission factors and methodologies.

—Offshore production facilities subject to subpart W must report stationary combustion emissions under subpart C of part 98.

—All Offshore production facilities, whether out of or under the jurisdiction of BOEMRE GOADS program are to adhere to the monitoring and QA/QC requirements in the applicable BOEMRE regulations.

• *EOR Hydrocarbon liquids dissolved* CO_2. Calculate CO_2 emissions downstream of storage tanks from hydrocarbon liquids produced as a result of enhanced oil recovery operations by conducting annual composition sampling of the produced hydrocarbon liquids by taking samples downstream of the storage tank. Use the mass of CO_2 from the sample to determine the mass of CO_2 dissolved in hydrocarbons beyond storage per barrel of produced liquid hydrocarbons.

• *EOR injection pump blowdown.* Calculate CO_2 emissions from enhanced oil recovery critical phase CO_2 injection pump blowdowns by calculating the volume of gas-containing structures between isolation valves, including piping. Use engineering estimates and best available data to determine the volume of gas-containing structures between isolation valves. The volumes calculated may be used in subsequent years if the hardware has not changed. Maintain logs of the number of blowdowns in the calendar year for each EOR pump. Using an appropriate standard method published by a consensus-based standards organization or, if no such standard exists, an industry standard practice, determine the density of the supercritical EOR injection gas. Calculate emissions using the number of blowdowns, the volume of the blown down equipment, the mass fraction of CO_2 in the injection gas, the density of the injection gas, and a conversion factor.

• *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2, CH_4 and N_2O combustion emissions from stationary and portable combustion equipment in onshore petroleum and natural gas production and stationary combustion equipment in natural gas distribution using the following methods:

—If the fuel combusted is listed in Table C–1 of subpart C, or any blend of the fuels listed, use the Tier 1 methodology of subpart C.

—Following the methodologies in 40 CFR 98.233(z), if the fuel combusted is field gas or a combination of field gas or process vent gas and one or more fuels listed in Table C–1 of subpart C, then use the volume of fuel and the composition of the fuel to calculate CO_2 emissions. If meters are installed on the fuel stream, the meter must be used to determine the volume of fuel combusted; otherwise the reporter can estimate that volume by installing a permanent flow meter or use engineering calculations. If a continuous gas analyzer is installed on the fuel stream, the composition reading must be used; otherwise another accepted method to estimate the composition may be used.

—Emissions from external fuel combustion sources with a rated heat capacity less than or equal to 5 mmBtu/hour do not have to be reported. Only activity data (unit count by type of unit) for such sources is to be reported.

—Calculate N_2O emissions from combustion equipment using emission factors and the fuel volume consumed. The high heat value of the fuel can be estimated using Table C–1 of subpart C if possible. If the fuel is field gas or process vent gas, a default high heat value is provided. If another fuel, not covered by Table C–1 of subpart C or field gas or process vent gas, is used; then the appropriate methodology from subpart C to estimate high heat value must be used.

Data Reporting Requirements. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)), reporters must submit additional data that are needed for EPA verification of the reported GHG emissions from petroleum and natural gas systems. The specific data to be reported are found in 40 CFR part 98, subpart W.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)), reporters must keep records of additional data used to calculate GHG emissions. These records are described in 40 CFR part 98, subpart W.

Definitions. EPA added definitions that are specific to subpart W to 40 CFR 98.238 to avoid any confusion with the definitions found in 40 CFR 98.6. For compliance with subpart W, the subpart W specific definitions apply instead of any of the same definitions also found in subpart A.

We are including a definition of the term "Offshore" in 40 CFR 98.238 to fully identify those petroleum and natural gas production platforms, secondary platforms and associated storage tanks covered by this rule.

We are also including two distinctive definitions of facility for onshore petroleum and natural gas production and for natural gas distribution. Defining a facility in these cases is not as straightforward as other industry segments covered under subpart W. For some segments of the industry (*e.g.,* onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures

[3] The Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) was formerly known as Minerals Management Service (MMS).

that lend themselves to identifying the scope of reporting and responsible reporting entities. However, in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging. As explained in the April 2010 proposal, EPA evaluated existing definitions used under current regulations and determined that it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage. For more information please see the preamble for the April 2010 proposal (75 FR 18608) and the Greenhouse Gas Emissions from Petroleum and Natural Gas Industry: Background Technical Support Document (EPA–HQ–OAR–2009–0923).

These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

First, as proposed in April 2010, the definition of natural gas distribution facility for this subpart is the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system. This facility definition provides clear reporting delineation because the equipment that they operate is clearly known, the ownership is clear to one company, and reporting at this level is consistent with 40 CFR part 98. In this action, EPA is finalizing this definition for the natural gas distribution industry segment. This facility definition for natural gas distribution will result in 90 percent GHG emissions coverage of this industry segment.

Second, as proposed in April 2010, the definition of an onshore petroleum and natural gas production facility for this subpart is all petroleum or natural gas equipment associated with all petroleum or natural gas production wells and CO_2 EOR operations that are under common ownership or common control including leased, rented, and contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility. In the April 2010 proposal, EPA evaluated at least two available industry recognized definitions that identify hydrocarbon basins: One from the United States Geological Survey (USGS) and the other from the American Association of Petroleum Geologists. Basins are mapped to county boundaries only to give a surface manifestation to the underground geologic boundaries. EPA decided to use the AAPG geologic definition of basin because it is referenced to county boundaries and hence likely to be familiar to the industry, *i.e.,* if the owner or operator knows in which county their well is located, then they know to which basin they belong. Hence, in this action, EPA is finalizing the facility definition at the basin level for the onshore petroleum and natural gas production industry segment because the operational boundaries and basin demarcations are clearly defined and are widely known, and reporting at this level would provide the necessary coverage of GHG emissions to inform policy. In addition, EPA has clarified its intent by stating that onshore petroleum and natural gas production equipment associated with all petroleum or natural gas production wells and CO_2 EOR operations continue to include any leased, rented or contracted activities by the owner or operator of those wells in that basin. This facility definition for onshore petroleum and natural gas production will result in 85 percent GHG emissions coverage of this industry segment.

Finally, in this final action, EPA has replaced the term "fugitive emissions" with "equipment leaks." This change was made to ensure consistency with the terminology in the Alternative Work Practice to Detect Leaks from Equipment for 40 CFR parts 60, 63, and 65.

E. Summary of Major Changes and Clarifications Since Proposal

The major changes and clarifications in subpart W since the April 2010 proposal are identified in the following list. For a full description of the rationale for these and any other significant changes to 40 CFR part 98, subpart W, see the Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems. The changes are organized following the different sections of the subpart W regulatory text.

1. Definition of the Source Category

- EPA revised the definition for onshore natural gas processing and onshore petroleum and natural gas production to exclude gathering lines and boosting stations from the source category.
- EPA revised the definition of onshore petroleum and natural gas production to include equipment on a well pad or associated with a well pad, due to the growing industry practice of multi-well pads, where equipment may serve one well on a pad or several wells on a pad.
- EPA has revised the definition of natural gas processing to clarify that this industry segment includes (1) all processing facilities that fractionate and (2) those that do not fractionate with throughput of 25 MMscf per day or greater.
- EPA has revised the definition for the natural gas processing industry segment by removing the term "plant" from the segment name to ensure consistency with terminology used by other industry segment definitions.
- EPA clarified that meters and regulators in the natural gas distribution industry segment do not include customer meters.

2. Reporting Threshold

- EPA is amending the reporting threshold language in subpart W to clarify that onshore petroleum and natural gas production facilities and onshore natural gas distribution facilities must report emissions only from sources specified in subpart W. This amendment was necessary to clearly define what emissions sources are to be included for considering the threshold in determining applicability for these two industry segments because they each have a different definition of the term "facility" than what is defined in the general provisions of part 98.

3. GHGs To Report

- EPA removed the reporting requirements for produced water from coal bed methane (CBM) and enhanced oil recovery (EOR) operations.

4. Monitoring, QA/QC, and Calculating Emissions

- For industry segments where equipment leak detection is required (onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage and LNG import and export equipment, and natural gas distribution facilities) EPA is including the option to use Method 21 and infrared laser beam illuminated instruments to detect leaks for sources that are accessible. Inaccessible equipment leaks and vented emissions are still required to be monitored using an optical gas imaging instrument.

• For applicable industry segments (onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage and LNG import and export equipment), EPA clarified the monitoring and reporting requirements for centrifugal and reciprocating compressors. Reporters are required to conduct an annual measurement of each compressor in the mode in which it is found at the time of the annual measurement. However, EPA requires reporters to conduct at least one measurement of each compressor in the not operating, depressurized mode during every 3-year period. Commenters suggested to EPA that based on their operational experience, 3 years is an appropriate maximum time period during which compressors will be shutdown at least once for routine maintenance, such that operators would not need to shutdown compressors specifically for the purposes of monitoring. For more detail, please see EPA–HQ–OAR–2009–0923–1011 excerpt 44. Also see "Compressor Modes and Threshold" Docket EPA–HQ–OAR–2009–0923.

• EPA clarified reporting requirements and in some cases included alternative data collection methodologies for certain sources to balance burden with data quality and emissions coverage:

—For onshore petroleum and natural gas production, EPA is allowing the use of major equipment counts and default average counts for associated components rather than requiring individual counts for all components to determine populations to which to apply component emission factors.

—As compressors in onshore petroleum and natural gas production are small in size, EPA is allowing the use of emission factors for calculating GHG emissions from centrifugal and reciprocating compressors in onshore petroleum and natural gas production rather than conducting an annual measurement of each compressor in the mode in which it is found.

—EPA is allowing onshore petroleum and natural gas production reporters to complete a total count of pneumatic devices any time within the first three calendar years. A reporter must report pneumatic device emissions annually. For any years where activity data (count of pneumatic devices) is incomplete, use best available data or engineering estimates to calculate pneumatic device emissions.

—For collecting gas composition data for produced natural gas, EPA is allowing reporters to use existing sampling data (*e.g.,* composition analysis of gas sold) if reporters do not have a continuous gas composition analyzer already installed.

—EPA is including emission factors for calculating GHG emissions from the following sources: vented GHG emissions from onshore petroleum and natural gas production tanks receiving oil from separators or directly from wells with less than 10 barrels per day throughput; onshore petroleum and natural gas production and onshore natural gas processing dehydrators with less than 0.4 million standard cubic feet per day throughput; vented GHG emissions from all onshore petroleum and natural gas production pneumatic devices and pneumatic pumps, and pneumatic devices in onshore natural gas transmission compression facilities and underground natural gas storage facilities.

—For both the onshore petroleum and natural gas production industry segment and the natural gas distribution industry segment, external fuel combustion emissions from portable or stationary equipment with rated heat capacity less than or equal to 5 mmBtu/hr, only activity data must be reported.

—Blowdown emissions from equipment vessel chambers totaling less than 50 cubic feet are not required to be reported.

—For reciprocating and centrifugal compressor measurement requirements, EPA clarified that the installation of permanent meters is an option but is not required; temporary meters are acceptable. In addition, through-valve leakage to open ended vents, such as unit isolation valves on not operating depressurized compressors and blowdown valves on pressurized compressors, may be measured using acoustic leak detection devices.

• EPA is allowing Best Available Monitoring Methods for certain sources and time periods (for more detailed information, refer to Section II.F of this preamble).

• For transmission storage tanks, EPA is allowing reporters to use an acoustic leak detection device to monitor leakage through compressor scrubber dump valves into the tank.

5. Applicability

To assist reporters in determining applicability, EPA is planning to develop screening tools to assist in the determination of which entities may potentially be required to report under subpart W of 40 CFR part 98.

F. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. EPA received many comments on this subpart covering numerous topics. EPA's responses to all comments, including those below, can be found in the comment response document for petroleum and natural gas systems in Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems. Additional comments and responses related to cost issues on the proposed rule can be located in Section III.B.2 of this preamble.

1. Definition of the Source Category

Comment: Numerous commenters objected to the inclusion of gathering lines and booster stations in the natural gas processing industry segment definition. Commenters specifically stated that including gathering lines and booster stations would result in undue burden on reporters stemming from (1) The additional cost to include gathering lines and boosting stations that typically are associated with a single natural gas processing facility, and (2) the numerous complexities and variations of ownership that currently exist with gathering lines and boosting stations. One commenter further detailed that there are at least three different owner/operator variations that exist ranging from a scenario where a single company owns and/or operates the wells, gathering lines, and natural gas processing facility, to a scenario where a single company owns the wells, a second distinct company (or multiple companies) own the gathering lines, and a third distinct company may own the natural gas processing facility. The commenter further explained that these scenarios are further complicated because the variations in gas flow fluctuate daily due to the need to balance production demands for natural gas against the capacity of the gathering lines and the natural gas processing facility.

Finally, a number of commenters requested that the gathering lines and boosting stations be excluded from the natural gas processing industry segment definition or be defined as a separate industry segment.

Response: EPA has decided not to include gathering lines and boosting stations as an emissions source in subpart W at this time. The primary reason for excluding gathering lines and boosting stations at this time is that emissions coverage from gathering lines and boosting stations within the natural gas processing industry segment requires further analysis to ensure an effective coverage of emissions from this source in order to appropriately inform future policy decisions. As a result, EPA is continuing to review the comments received and similar comments raised to ensure an effective coverage of emissions from this source, and is considering the most appropriate mechanism for future actions to address the collection of appropriate data on gathering lines and boosting stations while minimizing industry burden.

Comment: Several commenters stated that meters and regulators (M&R) were not clearly defined and could result in the inclusion of customer meters in the reporting requirements for the natural gas distribution industry segment.

Response: EPA did not intend to require reporting of GHG emissions from customer meters in subpart W. In this final action, EPA has clarified its intent to not require reporting of GHG emissions from customer meters. The definition of the natural gas distribution industry segment and the listing of GHGs to report under this industry segment have been refined to make clear what emissions are to be reported for this industry segment.

Comment: Commenters noted that many facilities would fall under more than one industry segment in a calendar year and requested clarification as to which industry segment such a facility would be required to report under. In addition some commenters noted that they have equipment from multiple industry segments located in the same physical space.

Response: EPA has reviewed these comments and has addressed them. Please see response to comment EPA–HQ–OAR–2009–0923–1024–14 in the Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments.

2. GHGs To Report

Comment: Numerous commenters argued against the reporting of emissions, specifically combustion emissions, from portable equipment for the onshore petroleum and natural gas industry segment. Commenters noted that tracking emissions from portable non-self propelled equipment would result in heavy burden due to the fact that the majority of portable equipment are operated by an entity that is separate from the owner. Further, commenters stated that the reporting of emissions from portable equipment will only marginally increase coverage of the proposed rule. Some commenters argued that subpart C excludes portable equipment from combustion emissions reporting, and questioned why it was required for subpart W.

Response: EPA disagrees with commenters and has finalized the reporting requirements for GHG emissions from portable non-self propelled equipment in subpart W, including emissions from drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters with external combustion rated heat capacity above 5 mmBtu/hour.

In order to manage the burden, the emissions estimation methods for portable equipment require the use of existing data, for the most part. Moreover, the allowance of Best Available Monitoring Methods (described later in this preamble) would provide reporters additional time to modify contractual arrangements with service providers. The decision to retain the reporting requirements for portable equipment GHG emissions was based on EPA's analysis of the contribution to GHG emissions, both combustion and process, from portable equipment in onshore production. It is estimated that portable non self-propelled equipment is responsible for over 45 percent of total emissions from onshore petroleum and natural gas production. Please see "Portable Combustion Emissions" Docket EPA–HQ–OAR–2009–0923 for the complete analysis. While EPA is not excluding portable equipment, for certain emissions sources, EPA agrees with comments that alternative methodologies are appropriate and viable for collecting these data. EPA has conducted an extensive review of the emissions contribution relative to reporting burden and modified the final rule to simplify the requirements for external combustion equipment that fall below a rated heat capacity of 5 mmBtu/hr for the onshore petroleum and natural gas industry segment and the natural gas distribution industry segment. Please see "Portable Combustion Emissions" Docket EPA–HQ–OAR–2009–0923 and "Equipment Threshold for Small Combustion Units" Docket EPA–HQ–OAR–2009–0923 for the analysis. Equipment that fall below the specified mmBtu level for the applicable industry segments would not have to conduct monitoring for combustion emissions, and would only be required to report activity data which would be total number of external fuel combustion units with a rated heat capacity of equal to or less than 5 mmBtu/hr by type of unit.

3. Monitoring, QA/QC, and Calculating Emissions

Comment: EPA received numerous comments on the use of the optical gas imaging instrument for detecting GHG emissions from equipment leaks. Several commenters expressed support for the use of optical gas imaging instruments prescribed in the rule, stating that using this equipment would result in cost savings to industry as it would reduce burden and time by quick survey of all emissions sources at one time. In addition, several commenters specifically requested that EPA also allow the use of organic vapor analyzers (OVA), toxic vapor analyzers (TVA) and infrared laser beam illuminated instruments as alternative technologies to the optical gas imaging instruments proposed for emissions detection.

Response: EPA has evaluated alternative methods for detection of equipment leaks for their viability and comparative accuracy to the optical gas imaging instrument in the proposed rule. EPA agrees with commenters and has modified the final rule to include the options to use OVA/TVA devices or infrared laser beam illuminated instruments for leak detection for all emissions sources across all industry segments with the exception of inaccessible sources. EPA is still requiring that reporters use optical gas imaging instruments for inaccessible sources due to potential safety and cost concerns related to leak detection of sources that cannot be physically accessed from a fixed, supportive surface with a hand held leak detection device such as OVA/TVA, or which do not have a reflective background for an IR laser detection device. While EPA has determined that the methodologies in this rule are viable and appropriate for collecting this type of GHG data, EPA will continue to evaluate other potential methods for detecting methane emissions in the petroleum and natural gas sector.[4]

Comment: Numerous commenters disagreed with EPA's assessment of the feasibility of conducting one measurement for each reciprocating or centrifugal compressor in each of the operational modes (operating, standby pressurized, not operating/depressurized) that would occur during a calendar year. Commenters specifically stated that common industry practice is to have a compressor in operating mode for several years before it is taken offline for routine maintenance and servicing, thereby taking a compressor offline for the sole purpose of measurement as

[4] While this activity is in a nascent stage, EPA is conducting ongoing research on experimental mobile monitoring methods to locate and quantify equipment leak emissions from petroleum and natural gas fields. In addition to increasing our knowledge about emissions from equipment leaks from petroleum and natural gas fields, if this proves to be a robust approach, it could be one viable alternative for measuring emissions and EPA would consider a rulemaking to add it as an acceptable method to this subpart.

prescribed in the rule would result in undue burden to the industry and result in additional GHG emissions.

Response: EPA did not intend for compressors to be taken offline in order for reporters to collect the data required under subpart W and has clarified the final rule to allow reporters to conduct an annual measurement of each compressor in the mode as it exists at the time the annual measurement is taken. EPA requires the development of emission factors from these measurements that reporters must apply appropriately to all compressors for the total time each compressor is operated in each mode. However, EPA requires that each compressor must be measured at least once during every 3-year period in the "not operating and depressurized" mode without blind flanges in place. Blind flanges are flat plates inserted between flanges on a valve or piping connection to assure absolute isolation of the equipment from process fluids, and hence, compromise through valve leakage measurement. Isolation valve leakage through the compressor blowdown vent, when the compressor is in the not operating and depressurized mode, must be measured before blind flanges are installed.

Commenters suggested to EPA that based on their operational experience, 3 years is an appropriate maximum operational time period during which compressors will be shutdown for maintenance at least once, and therefore operators would not need to shutdown compressors specifically for the purposes of monitoring to gather measurements at this frequency. Accordingly, EPA is requiring reporters to schedule the measurement of compressors in the not operating and depressurized mode at least once during each consecutive 3-year time period.

Comment: EPA received a broad range of comments that the methodologies for calculating GHG emissions in subpart W for specific emissions sources were too burdensome. Some commenters stated that quarterly sampling of produced natural gas to determine gas composition was overly burdensome and not necessary since produced gas composition does not change significantly from one quarter to the next. Other commenters suggested that requiring component counts for calculating equipment leaks for the onshore petroleum and natural gas industry segment was too onerous and time intensive since a reporter may have hundreds of wells across a large geographical area, and they currently do not have an inventory of all the components, such as valves, connectors and flanges, associated with their equipment. Several commenters stated that the number of tanks and dehydrators in the onshore petroleum and natural gas industry segment would be very burdensome to estimate emissions from using engineering equations. For example each tank would be required to obtain a sample analysis of low pressure separator oil for doing the engineering calculations. Finally, several commenters stated that the number of pneumatic devices and pneumatic pumps would require extensive time to determine the manufacturer model of each device in their facilities, and then estimate emissions based on manufacturer data.

Lastly, commenters noted that compressor emissions measurement and compressor throughput flow was too burdensome, since many compressors would require the installation of expensive permanent meters.

Response: EPA considered all of these comments, and performed extensive evaluation of the methodologies for calculating GHG emissions for each emissions source under each industry segment. EPA compared alternative methodologies that, when performed, would result in reduced burden on industry while maintaining the necessary quality of data to inform policy. Please see "Alternative Methodologies" Docket EPA–HQ–OAR–2009–0923 for a full report of the analysis. Specifically, certain methodologies for specific emissions sources allowed for alternative methods that would reduce burden and maintain data quality. As a result, EPA determined that the following rule modifications would reduce burden while sustaining the necessary quality of data:

- Individual component counts and population based emissions factors for onshore petroleum and natural gas production have been replaced with major equipment counts and default average component counts per primary equipment. Identification of primary equipment (dehydrators, compressors, heaters, *etc.*) will result in significantly less burden to reporters than counting each component (valve, flange, open-ended line, *etc.*).
- Quarterly sampling of gas composition has been replaced with using your most recent representative gas analysis. Most onshore petroleum and natural gas producers would have this information already for transaction processing.
- For onshore petroleum and natural gas production, for separators and well production with less than 10 barrels per day throughput and glycol dehydrators with less than 0.4 million standard cubic feet per day throughput, reporters will use emissions factors to determine emissions. Blowdown emissions from equipment vessel chambers totaling less than 50 cubic feet are not required to be reported. For more information, the following documents; "Equipment Threshold for Tanks," "Equipment Threshold for Dehydrators," and "Equipment Threshold for Blowdowns" can be found in docket EPA–HQ–OAR–2009–0923.
- For all pneumatic devices and pneumatic pumps in onshore petroleum and natural gas production and all pneumatic devices in onshore natural gas transmission compression facilities and underground natural gas storage facilities, reporters will utilize component counts and population emissions factors instead of engineering estimates. Note that onshore petroleum and natural gas production reporters must complete a total count of pneumatic devices any time within the first three calendar years. A reporter must report pneumatic device emissions annually. For any years where activity data (count of pneumatic devices) is incomplete, use best available data or engineering estimates to calculate pneumatic device emissions.
- The final rule has clarified that emissions from centrifugal and reciprocating compressors do not require the installation of a permanent flow meter; use of a portable meter and port are acceptable. In addition, through-valve leakage to open ended vents, such as unit isolation valves on not operating depressurized compressors and blowdown valves on pressurized compressors, may be measured using acoustic leak detection devices. In addition, compressor throughput flow meters are not required; estimates of compressor flow will be sufficient for EPA's requirements.

4. Data Reporting Requirements

Comment: Numerous commenters stated that there would be insufficient time, leak detection and measurement equipment, or service providers available to fully comply with subpart W reporting requirements. In particular, numerous onshore petroleum and natural gas production commenters expressed concern with the ability to gather data from geographically dispersed emissions sources starting January 1, 2011. Also numerous commenters from the onshore natural gas processing and onshore natural gas transmission industry segments expressed their concern with their ability to comply with monitoring requirements, such as installing necessary measurement ports or meters for measurement.

Response: As described below, EPA determined that for specified emissions sources for certain industry segments, some reporters may need more time to comply with the monitoring and QA/QC requirements of this subpart than by January 1, 2011. EPA carefully considered each source and the reporting compliance requirements and determined for which monitoring requirements it is appropriate to allow the use of best available monitoring methods, for how long the use of best available monitoring methods will be applicable, and under what circumstances these methods are reasonable. EPA has extensively detailed when and how reporters may use best available monitoring methods specified in the following sections and in 40 CFR 98.234(f) of the rule.

Best available monitoring methods are any of the following methods: monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart; supplier data; engineering calculations; or other company records. Best available monitoring methods are available for three specific instances as well as providing a catch-all provision in the case of unanticipated issues or circumstances. In each category EPA determined the affected sources, reporting requirements and the time period necessary for owners or operators to implement the requirements of the rule. In all cases, the owner or operator must use the equations and calculation methods set forth in 40 CFR 98.233, but may use best available monitoring methods to estimate the parameters in the equations as specified in the following sections.

EPA also carefully considered the timing for allowing application of best available monitoring methods. EPA determined the time duration for specified sources for which reporting entities may apply best available monitoring methods without a petition, and those for which reporting entities must request the use of best available monitoring methods. If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered. EPA reserves the right to review petitions after the deadline but will only consider and approve late petitions which demonstrate extreme or unusual circumstances. Based on EPA's experience in implementing the 2009 final rule and those BAMM provisions, EPA made the source specific determinations for subpart W as outlined in the following sections.

Well-Related Emissions Reporting. Subpart W requires the monitoring of well-related emissions sources for which the owner or operator must collect data during the actual event (for example, a well completion or workover conducted on a specific day in January 2011) and for which it may not be possible to collect or reproduce data after the event is over. EPA recognizes that a significant portion of well-drilling activities are conducted by third-party service providers and that in these cases, owners or operators may need to coordinate and possibly modify contracts, leases or other arrangements with service providers in order to gather data and thus it may not be possible for owners or operators to begin gathering well-related emissions data as of January 1, 2011. For these sources EPA will allow the use of best available monitoring methods through June 30, 2011 to allow reporters sufficient time to meet the requirements of the rule.

• *Eligible Sources.* There are three well-related sources for which subpart W requires emissions data collection at the time of the emissions event rather than at the reporter's discretion during a calendar year and for which use of best available monitoring methods will be allowed. These sources are as follows:

—Gas well workovers using hydraulic fracture in paragraph 40 CFR 98.233(g)
—Gas well completions using hydraulic fracture in paragraph 40 CFR 98.233(g)
—Well testing/flaring in paragraph 40 CFR 98.233(l)

• *Reporting Requirements.* For the eligible sources listed, an owner or operator must use the equations prescribed in 40 CFR 98.233(g) and 40 CFR 98.233(l) but may use best available monitoring methods to estimate any of the parameters. Best available monitoring methods may be:

—Monitoring methods currently used by the facility that do not meet the specifications of this subpart.
—Supplier data.
—Engineering calculations.
—Other owner or operator records.

• *Authorization to Use Best Available Monitoring Methods.* All owners or operators may use best available monitoring methods for these sources between January 1, 2011 and June 30, 2011. Owners or operators do not have to submit a request to EPA for the initial six months. Owners or operators will have from the time this rule is signed by the Administrator until June 30, 2011 to make any necessary arrangements with service providers and other relevant organizations in order for the owner or operator to gather all necessary data to comply with subpart W. As this is approximately eight months time, starting July 1, 2011, EPA expects that owners or operators will have made arrangements or modified contracts with service providers, such as drilling companies, as necessary to comply fully with subpart W for these sources.

• *Requests for Extension in 2011.* If additional time is necessary beyond June 30, 2011, an owner or operator must request an extension for use of best available monitoring methods by April 30, 2011. In order to receive an extension for a time period between July 1, 2011 and December 31, 2011, owners and operators must provide the following information for each source covered under 40 CFR 98.232(c)(6), 40 CFR 98.232(c)(8), and 40 CFR 98.232(c)(12):

—A list of the specific emissions sources within the owner or operator's facility for which the owner or operator is requesting an extension of best available monitoring methods.
—A description of the specific requirements in 40 CFR 98.233(g) and 40 CFR 98.233(l) that the owner or operator cannot meet in 2011, including a detailed explanation as to why the requirements cannot be met.
—Supporting documentation such as the date of and copies of correspondence to service providers or other relevant entities whereby the owner or operator clearly requests that said service providers or other relevant entities provide required data.
—Demonstrate that it is not possible to obtain the necessary information, service or hardware which may include providing correspondence from specific service providers or other relevant entities to the owner or operator, whereby the service provider states that it is unable to provide the necessary data or services requested by the owner or operator that would enable the owner or operator to comply with subpart W reporting requirements.
—A detailed explanation and supporting documentation of how and when the owner or operator will receive the required data and/or services to comply with subpart W reporting requirements.

The Administrator reserves the right to require additional documentation.

EPA does not anticipate extending the use of best available monitoring methods beyond 2011 as approximately fourteen months will have passed since the Administrator's signature; however, under extreme and unique circumstances, which include safety, or a requirement being technically infeasible or counter to other local, State or Federal regulations, EPA may consider granting a further extension. Any such request must be received by September 30, 2011. The owner or operator must provide the following information in a request for the use of best available monitoring methods beyond 2011 for sources covered under 40 CFR 98.232(c)(6), 40 CFR 98.232(c)(8), and 40 CFR 98.232(c)(12) for beyond 2011:

—A list of the specific emissions sources within the owner or operator's facility for which the owner or operator is requesting an extension of best available monitoring methods.
—A description of the specific requirements in 40 CFR 98.233(g) and 40 CFR 98.233(l) that the owner or operator cannot meet, including a detailed explanation as to why the requirements cannot be met.
—Detailed outline of the unique circumstances necessitating an extension, including specific data collection issues that do not meet safety regulations, technical

infeasibility or specific laws or regulations that conflict with data collection for 40 CFR 98.232(c)(6), 40 CFR 98.232(c)(8), and 40 CFR 98.232(c)(12). The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists. For example, if measuring an open-ended line on a rooftop does not meet safety regulations, companies must consider the use of portable meters using a port at ground-level.

—A detailed explanation and supporting documentation of how and when the owner or operator will receive the required data and/or services to comply with subpart W reporting requirements in the future.

The Administrator reserves the right to require additional documentation.

• It is the responsibility of the owner or operator to meet the reporting requirements of this rule. Accordingly, it is up to the owner or operator to best determine how they can obtain the necessary data to timely and fully comply.

Stipulated Activity Data Collection. Several sources require the collection of activity data such as cumulative run time or a cumulative throughput volume to a piece of equipment starting January 1, 2011. Based on industry comments, EPA recognizes that it may not be feasible for an owner or operator to gather these data across all of their facilities as data collection in some cases must begin on January 1, 2011. EPA has decided to allow reporters to use best available monitoring methods to estimate specific activity parameters used in the equations and methods outlined in 40 CFR 98.233 for the first six months of 2011. EPA will allow the use of best available monitoring methods for emissions sources for which the owner or operator must collect activity data sometime between January 1, 2011 and June 30, 2011 and the owner or operator cannot reproduce or replicate the data after this time period. As owners or operators will have approximately eight months from the time of Administrator signature to June 30, 2011 to develop systems to collect these data, EPA does not anticipate approving best available monitoring methods for collecting activity data after June 30, 2011.

• Eligible Sources. Owners and operators may use best available monitoring methods only for the sources listed below:

—Cumulative hours of venting, days, or times of operation in paragraphs § 98.233(e), (f), (g), (h), (l), (o), (p), (q), (r) of 40 CFR part 98.

—Number of blowdowns, completions, workovers, or other events in paragraphs § 98.233(f), (g), (h), (i), and (w) of 40 CFR part 98.

—Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z) of 40 CFR part 98.

• Reporting Requirements. For the sources eligible for best available monitoring methods applicable to stipulated activity data,, owners and operators must use the equations prescribed in 40 CFR 98.233 but may use best available monitoring methods to estimate the stipulated activity parameters. Best available monitoring methods are:

—Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

—Supplier data.

—Engineering calculations.

—Other owner or operator records.

• Authorization to Use Best Available Monitoring Methods. All owners and operators may use best available monitoring methods for the sources eligible for best available monitoring methods applicable to stipulated activity data between January 1, 2011 and June 30, 2011. Owners or operators do not have to submit a request to EPA for the initial six months. As owners and operators will have approximately eight months from Administrator signature to June 30, 2011, to prepare for the data collection requirements for the eligible sources, EPA expects that all owners or operators should have had adequate time to comply with the data collection requirements outlined in this subpart and therefore not need the use of best available monitoring methods for this information after June 30, 2011.

• Requests for Extension in 2011. Only under extreme circumstances, which include safety, or a requirement being technically infeasible or counter to other local, State, or Federal regulations, will EPA consider extending the use of best available monitoring methods for the collection of activity data through the end of 2011.

• Owners or operators may submit a request for an extension through the end of 2011. These requests must be received by April 30, 2011 and include the following:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

—A description of the specific requirements in paragraphs § 98.233(e), (f), (g), (h), (i), (j), (k), (l), (m), (n), (o), (p), (q), (r), (w), (x), (y), and (z) of 40 CFR Part 98 that the owner or operator cannot meet, including a detailed explanation as to why the requirements cannot be met.

—Detailed outline of the unique circumstances necessitating an extension, including data collection methods that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with the specific sources in this section of the preamble. The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.

—A detailed explanation and supporting documentation of how and when the owner or operator will receive, for example, the services or equipment to comply with subpart W reporting requirements.

The Administrator reserves the right to require additional documentation.

• Requests for Extension beyond 2011. As approximately fourteen months will have passed between the Administrator's signature and December 31, 2011, EPA does not anticipate approving requests for best available monitoring methods beyond 2011 for applicable stipulated activity data sources eligible for best available monitoring methods; however, under extreme and unique circumstances, which include safety, a requirement being technically infeasible or counter to other local, State, or Federal regulations, it may consider granting a further extension. Any such requests for extensions beyond 2011 must be received by September 30, 2011 and include the following:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

—A description of the specific requirements in paragraphs § 98.233(e), (f), (g), (h), (i), (j), (k), (l), (m), (n), (o), (p), (q), (r), (w), (x), (y), and (z) of 40 CFR Part 98 that the owner or operator cannot meet, including a detailed explanation as to why the requirements cannot be met.

—Detailed outline of the unique circumstances necessitating an extension, including data collection methodologies that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with sources outlined in this section of the preamble. The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.

—A detailed explanation and supporting documentation of how and when the owner or operator will receive, for example, the services or equipment to comply with subpart W reporting requirements.

The Administrator reserves the right to require additional documentation.

Acquisition and implementation of leak detection and monitoring equipment or services. Based on industry comments, EPA understands that it may not be feasible for all owners or operators to acquire required leak detection and/or measurement equipment or hire a service provider in time to conduct the activities necessary to complete leak detection and measurement requirements under subpart W within the 2011 calendar year. EPA will consider the use of best available monitoring methods for sources requiring leak detection and/or measurement based on evidence provided by the owners or operators demonstrating that they have made all efforts but cannot obtain the necessary equipment or services in time to complete subpart W reporting in 2011.

• Eligible Sources. With application approval from the Administrator, owners and operators may use best available monitoring methods only for the sources listed below:

—Reciprocating compressor rod packing vents for facilities downstream of onshore petroleum and natural gas production (*i.e.,* onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment) in 40 CFR 98.233(p).
—Centrifugal compressor wet seal oil degassing venting for facilities downstream of petroleum and natural gas production in 40 CFR 98.233(o).
—Acid gas removal vents in 40 CFR 98.233(d).
—Equipment leaks in facilities downstream of onshore petroleum and natural gas production in 40 CFR 98.233(q).
—Transmission storage tanks in 40 CFR 98.233(k).

• Reporting Requirements. For the sources eligible for best available monitoring methods applicable to acquisition and implementation of leak detection and monitoring equipment or services,, if approved by the Administrator, the owner or operator may use best available monitoring methods to estimate emissions and/or the number of leaking components, and any throughputs, volumes, or maintenance records in place of the required monitoring methods outlined for parameters in 40 CFR 98.233. These best available monitoring methods are:

—Monitoring methods currently used by the facility that do not meet the specifications of this subpart.
—Supplier data.
—Engineering calculations.
—Other owner or operator records.

• Authorization to Use Best Available Monitoring Methods. Because leak detection and/or measurement surveys are one-time actions that can be conducted at any time during the year, by April 30, 2011, reporters must submit an application seeking approval for the use of best available monitoring methods. Upon approval by the Administrator, EPA may allow the use of best available monitoring methods for up to the entire 2011 calendar year. An owner or operator must submit this request no later than April 30, 2011 and include, at a minimum:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.
—A description of the specific requirements in 40 CFR 98.233(d), 98.233(k), 98.233(o), 98.233(p), and 98.233(q) that the owner or operator cannot meet and an explanation of how the owner or operator has diligently tried and why it cannot meet the requirements.
—Certification that the owner or operator does not already own relevant detection or measurement equipment.
—Documentation which demonstrates that the owner or operator made all reasonable efforts to obtain the service necessary to comply with subpart W reporting requirements in 2011, including evidence of specific service or equipment providers contacted and why services could not be obtained during 2011. EPA recognizes that some owners or operators may choose to conduct their own leak detection and measurement activities and therefore purchase equipment for that purpose. It is the owner or operator's responsibility to purchase all necessary equipment in time to meet 2011 reporting requirements. If relevant equipment vendors cannot deliver hardware in time for an owner or operator to meet subpart W requirements, the owner or operator must attempt to use outside service providers, prior to seeking a request for best available monitoring methodology extension.
—A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with subpart W reporting requirements in 2012.

The Administrator reserves the right to require additional documentation.

• Requests for Extension. As owners and operators will have had approximately fourteen months since the date of the Administrator's signature and December 31, 2011, EPA does not anticipate extending best available monitoring methods beyond 2011; however, under extreme and unique circumstances, which include safety, or a requirement being technically infeasible or counter to other local, State, or Federal regulations, EPA may consider granting a further extension. Any such request for extensions beyond 2011 must be received by September 30, 2011 and include the following:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.
—A description of the specific requirements in 40 CFR 98.233(d), 98.233(k), 98.233(o), 98.233(p), and 98.233(q) for which extension is being requested and of the unique circumstances necessitating an extension, including specific data collection methodologies that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with sources outlined in this section of the preamble. The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.
—Detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with subpart W reporting requirements.

The Administrator reserves the right to require additional documentation.

Unique or Extreme Circumstances

• Requests for 2011: Emissions sources not covered under the previous three categories of BAMM are under operational control of the owner or operator, require one time data collection at any point during the calendar year and do not require leak detection or measurement equipment. For these reasons, for the sources not covered under the previous three categories of BAMM, EPA does not anticipate the need for best available monitoring methods; however, EPA will review all requests submitted by April 30, 2011 and consider approval of the use of best available monitoring methods for 2011 under unique and extreme circumstances, which include safety, or requirement being technically infeasible or counter to other local, State, or Federal regulations. Requests for the use of best available monitoring methods for sources not covered under the previous three categories of BAMM must include:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.
—Detailed outline of the unique circumstances necessitating an extension, which must include data collection methodologies that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with specific sources for which owners or operators are requesting best available monitoring methods. The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.
—A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with subpart W reporting requirements in 2012.

The Administrator reserves the right to require additional documentation.

• Requests beyond 2011: For sources not covered in the previous three categories of BAMM, EPA does not anticipate the need for best available monitoring methods beyond 2011;

however, EPA will review such requests submitted by September 30, 2011 and consider approval of the use of best available monitoring methods for 2012 under unique and extreme circumstances, which include safety, or a requirement being technically infeasible or counter to other local, State, or Federal regulations. Requests for the use of best available monitoring methods for sources not covered in the previous three categories of BAMM, must include:

—A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.
—Detailed outline of the unique circumstances necessitating an extension, which must include data collection methodologies that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with specific sources for which owners or operators are requesting best available monitoring methods. The owner or operator must consider all data collection options as outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.
—A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with subpart W reporting requirements.

The Administrator reserves the right to require additional documentation.

5. Legal Authority

Comment: Several commenters asserted that EPA is over-reaching its CAA 114 authority. These commenters specifically stated that CAA section 114 does not authorize EPA to require indefinite and sweeping monitoring, recordkeeping, and reporting from the facilities covered by proposed subpart W. On the other hand, several commenters asserted that the proposal was within EPA's authority under the CAA.

Response: As explained in Section I.C. of this preamble, Section I.C and Q of the 2009 final Part 98 preamble (74 FR 56260), and the document Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Volume 9, Legal Issues (EPA–HQ–OAR–2008–0508), EPA is promulgating subpart W under its existing CAA authority provided in CAA section 114. EPA disagrees with the commenters that it does not have statutory authority to require monitoring, reporting and recordkeeping from facilities in the petroleum and natural gas systems source category. The Administrator may gather information under CAA section 114, as long as that information is for purposes of carrying out any provision of the CAA. For example, CAA section 103 authorizes EPA to establish a national research and development program, including non-regulatory approaches and technologies, for the prevention and control of air pollution, including GHGs. The data collected under this rule will also inform EPA's implementation of CAA section 103(g) regarding improvement in sector based non-regulatory strategies and technologies for preventing or reducing air pollutants. For more information about EPA's legal authority please see the related sections and documents in the preamble for subpart W.

6. Designated Representative

Comment: Several commenters stated that EPA lacked the authority to require facilities to collect data on equipment and activities that may be operated or provided by a third party service provider and then require a designated representative to certify those emissions data. Other commenters supported the inclusion of emissions data from equipment operated by third party service providers by stating that these emissions are critical to ensuring that facilities with different operational structures have equitable coverage in a reporting program and that a complete profile of emissions from the production sector is obtained.

Response: As explained in Section V of the preamble of the 2009 final part 98 (74 FR 56355), all reporters must select a designated representative (DR) who is responsible for certifying, signing, and submitting all submissions to EPA. This provision provides flexibility to the owners and operators to choose any individual, employee or non-employee, to represent them, while ensuring EPA has one accountable point of contact. As explained in the preamble to the final part 98, the high level of public interest in the data collected, as well as its importance to future policy, warrants establishment of a high standard for data quality and consistency and high level of accountability for reported data. The DR provisions and certification requirements help ensure the standard for high quality data and consistency is met. The DR provisions are crafted similarly to the provisions of the Acid Rain Program (ARP), 40 CFR part 72 and EPA has found that this approach provides a high degree of both data quality and consistency and accountability.

Similar comments were made about the data coming from multiple owners and operators and the concerns about the certification of those data upon promulgation of the ARP and the 2009 final GHG reporting rule to which we responded, and for which responses are summarized. We have attempted to provide maximum flexibility while ensuring accountability. For integrity of the program, one representative of the owners and operators must report for important reasons. Doing so ensures the accountability of owners or operators by, *inter alia,* reducing the likelihood of inconsistent submissions by a facility. Interposing another person or party between the facility and the Agency would dilute the DR's responsibility and in effect create multiple DRs for the facility. Additionally, leaving the ultimate responsibility of submission with the designated representative has the salutary effect of clarifying that the DR should be aware of all submissions and should inquire of the persons with personal knowledge of the information in those submissions. The DR has the flexibility to delegate duties, such as the preparation of submissions, but retains the ultimate responsibility to sign and certify all submissions. (*See,* 58 FR 3590, 3598, January 11, 1993.)

Furthermore, while the DR or his delegatee may need to acquire necessary reporting information from a third party, the DR must make the appropriate inquiries and certification when reporting; ultimate responsibility rests and must necessarily rest on him or her. The DR may provide in contracts, leases, or other agreements with third parties that true, accurate, and correct reporting information must be provided to the DR in a timely fashion. If the third party fails to provide timely, true, accurate, or correct information to the DR, then the DR has recourse contractually, or otherwise, on the third party. Finally, in recognition of their potential need to adjust contracts, leases, or agreements accordingly, additional flexibility has been provided in the rule to allow facilities to utilize best available monitoring methods for a limited period. For more information, see Section V of the preamble to the 2009 final Part 98 (74 FR 56260) and the document Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Volume 11, Designated Representative and Data Collection, Reporting, Management and Dissemination (EPA–HQ–OAR–2008–0508).

7. Applicability

Comment: Multiple commenters requested that EPA develop a set of screening tools to assist in the determination of which entities would be required to report under subpart W of 40 CFR part 98.

Response: Similar to what EPA has already provided for other subparts of the Greenhouse Gas Reporting Program to help reporters assess the applicability of the Greenhouse Gas Reporting Program [5] to their facilities, EPA plans to develop voluntary screening tools for the petroleum and natural gas source category. EPA anticipates that such tools would be based on easily determined inputs such as major equipment or operational counts. While the tools would be designed to provide help to potential reporters for complying with the rule, compliance with all Federal, State, and local laws and regulations remain the sole responsibility of each facility owner or operator subject to those laws and regulations. The tools would be a guide to determine those facilities that are clearly well below the reporting threshold, those clearly above, and those close to the threshold who will need to collect further data to make a proper determination.

III. Economic Impacts of the Rule

This section of the preamble summarizes the costs and economic impacts of the final subpart W rulemaking, including the estimated costs and benefits of subpart W, and the estimated economic impacts on affected facilities, including estimated impacts on small entities. Complete details of the economic impacts of the final subpart W rule can be found in the Economic Impact Analysis (EIA) in the rulemaking docket (EPA–HQ–OAR–2009–0923).

This section also contains a brief summary of major comments and responses on the economic impacts of the rule. EPA received a number of comments on the estimated compliance costs as well as other comments covering a variety of topics. Responses to significant comments can be found in Mandatory Greenhouse Gas Reporting Program: EPA's Response to Public Comments, Cost and Economic Impacts of the Rule, Docket EPA–HQ–OAR–2008–0508.

A. How were compliance costs estimated?

1. Summary of Method Used To Estimate Compliance Costs of the Final Rule

EPA estimated costs for each affected petroleum and natural gas industry facility to comply with subpart W. These estimates capture the costs associated with monitoring and reporting both equipment leaks and vented emissions and incremental combustion-related emissions.[6] EPA based the estimates on the number of labor hours to perform specific activities, the cost of labor, and the cost of monitoring equipment.

The costs of complying with the rule will vary from one petroleum and gas industry segment and facility to another, depending on factors such as the types of emissions, the number of affected sources at the facility and existing maintenance practices, monitoring, recordkeeping, and reporting activities at the facility. The costs include expenditures related to monitoring, recording, and reporting process emissions and, as relevant, emissions from stationary combustion.

Staff activities and associated labor costs may also vary over time. In particular, start-up activities, such as the installation of ports for compressors to allow for spot measurements, result in notably higher costs in the first year. Costs would also vary over time when site-specific emissions factors are developed every 2 or 3 years. Thus, EPA developed cost estimates for year one, which include start-up and first-time reporting, and for subsequent year reporting.

EPA estimated annual costs in 2006 dollars using the 2006 population of emitting sources. In addition, the agency estimated costs on a per entity basis and weighted them by the number of entities affected at the 25,000 metric tons CO_2e threshold.

To develop compliance cost estimates, EPA gathered existing data from EPA studies and publications, industry trade associations and publicly available data sources (*e.g.,* labor rates from the Bureau of Labor Statistics) to characterize the processes, sources, segments, facilities, and companies/entities affected. EPA also considered cost data submitted in public comments on the proposed rule.

Next, EPA estimated the number of affected facilities in each source category, the number and types of process equipment at each facility, the number and types of processes that emit GHGs, process inputs and outputs (especially for monitoring procedures that involve a carbon mass balance), and data that are already being collected for reasons not associated with the rule (to allow only the incremental costs to be estimated).

Labor Costs. The costs of complying with and administering this rule include time of managers, and of technical, operational and administrative staff in the private sector. Staff hours were estimated for activities, including:

- Developing a plan: Reporting entity management, legal, and technical staff hours to determine applicability of the rule, organize training on rule requirements, identify staffing assignments, train staff, and schedule activities as required below.
- Setting up records: Technical and field staff hours to develop data collection sheets and analytical model equations or linkages to input data into software programs.
- Collecting field data: Technical and field staff hours to collect necessary site-specific data and input that data into the analytical input tables.
- Monitoring: Staff hours to procure, install, operate and maintain emissions monitoring equipment, instruments and engineering analysis systems.
- Engineering models: Technical staff hours to link and execute engineering emissions estimation models and analytical procedures and to organize output data as required for reporting emissions.
- Recordkeeping: Staff hours required to organize, file and secure critical data and emissions quantification results as required for reporting and for documenting determinations of facilities exceeding and not exceeding reporting thresholds.
- Reporting: Management and staff hours to organize data, perform quality assurance/quality control, inform key management personnel, and report it to EPA through electronic systems.

Estimates of labor hours were based on economic analyses of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored; and engineering judgment by industry and EPA industry experts and engineers. See the Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Final Rule (EPA–HQ–OAR–2009–0923) for a detailed discussion about the engineering analysis used to develop these estimates. In addition, the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923) provides a discussion of the applicable engineering estimating and measurement technologies and any existing programs and practices.

EPA monetized the labor hours using wage rates from the Bureau of Labor Statistics (BLS). The agency also adjusted the wage rates to account for overhead.

[5] *http://www.epa.gov/climatechange/emissions/GHG-calculator/index.html.*

[6] Reporting entities that equal or exceed the subpart W threshold for equipment leak and vented emissions must report combustion emissions under subpart C, except for onshore production and LDCs, which must report combustion emissions under subpart W. Incremental combustion emissions refer to those from entities that did not trigger the subpart C threshold in the absence of subpart W.

Equipment Costs. Equipment costs include both the initial purchase price of monitoring equipment and installation cost. For example, the cost estimation method for large compressor seal emissions includes both purchase of a flow measurement instrument and installation of a measurement port in the vent piping where the end of the vent is inaccessible. Based on expert judgment, the engineering cost analyses annualized capital equipment costs with appropriate lifetime and interest rate assumptions. Cost recovery periods and interest rates vary by industry, but typically, one-time capital costs are amortized over a 5-year cost recovery period at a rate of seven percent. Not all segments require monitoring equipment capital expenditures but those that do are clearly documented in the Economic Impact Analysis.

Incremental Combustion Costs. EPA estimated the costs to monitor and report incremental combustion emissions, which are combustion-related emissions from entities that did not trigger the subpart C threshold in the absence of subpart W. As discussed earlier in this section, reporting entities that equal or exceed the subpart W threshold must report combustion emissions following the methods under subpart C, except for onshore production entities that consume field gas or process vent gas and LDCs, which must report combustion emissions following the methods under subpart W.

For purposes of cost estimation, EPA determined that under the final rule, entities that need to report incremental combustion-related emissions, as previously defined, would likely use either the Tier 1 calculation methodology as set forth in subpart C or the calculation methodology as set forth in subpart W (40 CFR 98.233(z)). EPA determined that the entities reporting incremental emissions under subpart C would likely not meet the requirements for Tier 2 or higher methods. However, as these entities will be reporting combustion emissions under subpart C (except onshore production and LDCs), if a facility did meet the requirements for a tier other than Tier 1, the facility would have to use the required method, as specified in subpart C.

Given that the combustion methodology in 40 CFR 98.233(z) is similar to the Tier 1 calculation methodology, EPA estimated the costs to monitor and report incremental combustion-related emissions based on the approach used under 40 CFR part 98, subpart C.[7] Specifically, EPA applied the Tier 1 calculation methodology to estimate the costs to monitor combustion emissions that became subject to reporting as a result of this final action. The Tier 1 approach bases estimates on a fuel-specific default CO_2 emission factor, a default high heating value of the fuel, and the annual fuel consumption from company records.

EPA based its conclusion that entities would likely report incremental combustion emissions using the Tier 1 method on three considerations for applicability of the Tier 2 calculation methodology and higher, as specified in subpart C, to the petroleum and natural gas industry: (1) Availability of high heating values (HHVs) for the fuels combusted at the frequency required by the Tier 2 calculation methodology, (2) the maximum rated heat capacity of the equipment, and (3) the type of fuel being combusted. First, in order to be allowed to use a Tier 2 analysis, units must have a rated heat capacity less than or equal to 250 mmBtu/hr, combust a fuel found in Table C–1 of subpart C, and sample the HHV of the fuel consumed at the required frequency in 40 CFR 98.34(a). It was determined that this minimum required sampling frequency is not currently carried out at these smaller units and therefore these units would not be required to use Tier 2 methodology. These units will generally follow Tier 1 methodology.

Second, Tier 3 and Tier 4 calculation methodologies generally apply to equipment with a maximum rated heat capacity greater than 250 mmBtu/hr. A 250 mmBtu/hr rating means that the emissions from that individual unit alone will be greater than 25,000 metric tons CO_2e; these emissions would be subject to reporting under subpart C even in the absence of subpart W and therefore would not fall in the category of incremental combustion emissions considered in this analysis.

Third, the predominant fuels used in the petroleum and natural gas industry are produced natural gas, pipeline quality natural gas, distillate fuel, and any products recovered from equipment leaks and vents. The use of produced natural gas is predominant in onshore petroleum and natural gas production. Under the final rule for subpart W, reporters in this segment are allowed to use methods similar to Tier 1 for all combustion emissions sources that use produced natural gas.

In the remaining segments, equipment using produced natural gas or products recovered from equipment leaks and vents are normally required to use Tier 2 methodology or higher. However, as described previously, if the unit has a rated heat capacity less than or equal to 250 mmBtu/hr, then the unit probably does not currently receive HHV at the required frequency for a Tier 2 analysis and could use a Tier 1 analysis instead. If the unit has a maximum rated heat capacity greater than 250 mmBtu/hr, then as just noted, emissions from a unit of this size would already be subject to reporting under subpart C and would not be included in the incremental combustion emissions category considered in this analysis. In sum, the use of Tier 1 methodology for incremental combustion is a reasonable assumption for costing the subpart W rule.

Reporting Determination Costs. Facilities will have to estimate their emissions to determine whether they exceed the reporting threshold. The costs for making a reporting determination includes primarily the use of screening tools, which EPA plans to develop. The costs also account for cases in which preliminary monitoring is also required to make a reporting determination.

2. Summary of Comments and Responses

EPA received many comments on the method used to estimate the rule's compliance costs. Nearly all of these comments focused on both the methodology and the resulting cost estimates. Therefore, a summary of these comments and EPA's response is presented in the next section of this preamble, Section III.B.2, What are the costs of the rule? For the detailed responses to all comments received, see Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems (EPA–HQ–OAR–2009–0923).

B. What are the costs of the rule?

1. Summary of Costs

Table 6 of this preamble presents for each segment the total costs and costs per ton in the first year and subsequent years as well as the annualized costs. EPA estimates that the total private sector cost in the first year is about $62 million and about $19 million for subsequent years; the annualized cost over a 20-year time period is about $21 million (3 percent discount rate) and $22 million (7 percent discount rate) (2006$). Of these costs, EPA estimates

[7] 40 CFR part 98 uses the IPCC Tier concept to estimate combustions emissions (74 FR 56260, October 30, 2009). See EPA–HQ–OAR–2008–0508–0004, U.S. EPA, Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases, January 30, 2009, for more information about the IPCC Tier methodology (pgs 10–15).

roughly $40 million to report process emissions in the first year and about $15 million in subsequent years. In addition, EPA estimates approximately $3 million to report incremental combustion related emissions in both the first year and in the subsequent years.

The reporting threshold determines the number of entities required to report GHG emissions and hence the costs of the rule. The number of entities excluded increases with higher thresholds. Table 7a and Table 7b of this preamble provide the cost-effectiveness analysis for various thresholds examined. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per metric ton of emissions reported ($/metric ton CO_2e). The second metric for evaluating the threshold option is the incremental cost per metric ton of emissions reported. The incremental cost is calculated as the additional (incremental) cost per metric ton using 25,000 metric tons CO_2 equivalent as the baseline. For more information about the first year capital costs (unamortized), project lifetime and the amortized (annualized) costs for each petroleum and gas industry segment please refer to Section 4 of the Economic Impact Analysis for the final subpart W.

TABLE 6—NATIONAL COST ESTIMATES FOR PETROLEUM AND NATURAL GAS SYSTEMS

[2006$] [1]

Segment	First year		Subsequent year		Annualized cost (3%) [2] ($million)	Annualized cost (7%) [3] ($million)
	National cost ($million)	Cost ($/metric ton)	National cost ($million)	Cost ($/metric ton)		
Processing	8.13	0.26	2.10	0.07	2.43	2.57
Transmission	16.87	0.40	6.49	0.15	7.02	7.26
Underground Storage	2.73	0.35	1.02	0.13	1.10	1.14
LNG Storage	0.70	0.41	0.26	0.15	0.28	0.29
LNG import/export	0.14	0.44	0.03	0.09	0.04	0.04
LDC	3.31	0.15	1.35	0.06	1.47	1.52
Onshore Production	26.58	0.12	7.54	0.03	8.61	9.05
Offshore Production	3.33	0.65	0.24	0.05	0.42	0.49
Total (8 Segments)	61.78	0.18	19.01	0.06	21.36	22.34

[1] Includes determination costs for non-reporters. These estimates are conservative and should be viewed as an upper-bound because the determination costs were applied at the facility-level rather than the company-level. For example, for offshore production, determination costs were applied to each of the approximately 3,000 platforms in the Gulf of Mexico rather than the 86 operators in that region. See the memo, "Estimates of Determination Costs," in the docket for complete details and additional determination cost estimates (EPA–HQ–OAR–2009–0923).

[2] The cost to report annualized over 20 years at 3 percent (see additional details in section 5 of the EIA for the final rule).

[3] The cost to report annualized over 20 years at 7 percent (see additional details in section 5 of the EIA for the final rule).

TABLE 7A—THRESHOLD COST-EFFECTIVENESS ANALYSIS

[First Year, 2006$]

Threshold (metric tons CO_2e)	Facilities required to report	Total costs [1] (million 2006$)	Downstream emissions reported ($MtCO_2e$/year)	Percentage of total downstream emissions reported	Average reporting cost ($/Mt) [1]	Incremental cost ($/Mt) [1,2]
1,000	12,622	$148.67	391	99%	$0.38	$1.62
10,000	4,400	79.01	362	91%	0.22	0.69
25,000	2,786	61.78	337	85%	0.18	0.00
100,000	1,062	44.32	273	69%	0.16	(0.27)

[1] Includes determination costs for non-reporters. The upper-bound first-year determination cost estimates for each threshold are as follows: 1,000 metric tons CO_2e = $12.3 million; 10,000 metric tons CO_2e = $17.4 million; 25,000 metric tons CO_2e = $18.4 million; and 100,000 metric tons CO_2e = $19.3 million. As noted in previous table, these estimates are conservative. See the memo, "Estimates of Determination Costs," in the docket for complete details and additional determination cost estimates (EPA–HQ–OAR–2009–0923).

[2] Cost per metric ton relative to the selected option (25,000 MT threshold).

TABLE 7B—THRESHOLD COST-EFFECTIVENESS ANALYSIS

[Subsequent Year, 2006$]

Threshold (metric tons CO_2e)	Facilities required to report	Total costs [1] (million $2006)	Downstream emissions reported ($MtCO_2e$/year)	Percentage of total downstream emissions reported	Average reporting cost ($/Mt) [1]	Incremental cost ($/Mt) [1, 2]
1,000	12,622	$73.44	391	99%	$0.19	$1.02
10,000	4,400	30.51	362	91%	0.08	0.46
25,000	2,786	19.01	337	85%	0.06	0.00

TABLE 7B—THRESHOLD COST-EFFECTIVENESS ANALYSIS—Continued

[Subsequent Year, 2006$]

Threshold (metric tons CO_2e)	Facilities required to report	Total costs [1] (million $2006)	Downstream emissions reported ($MtCO_2e$/year)	Percentage of total downstream emissions reported	Average reporting cost ($/Mt) [1]	Incremental cost ($/Mt) [1, 2]
100,000	1,062	9.77	273	69%	0.04	(0.14)

[1] Includes determination costs for non-reporters. The upper-bound determination costs in subsequent years for each threshold are as follows: 1,000 metric tons CO_2e = $1.8 million; 10,000 metric tons CO_2e = $1.0 million; 25,000 metric tons CO_2e = $0.6 million; and 100,000 metric tons CO_2e = $0.2 million. As noted in previous table, these estimates are conservative. See the memo, “Estimates of Determination Costs,” in the docket for complete details and additional determination cost estimates (EPA–HQ–OAR–2009–0923).

[2] Cost per metric ton relative to the selected option (25,000 MT threshold).

2. Summary of Comments and Responses

Overview. EPA received extensive comments on the methodology and cost data presented in the Economic Impact Analysis for the proposed subpart W (EPA–HQ–OAR–2009–0923–0020). The comments can be sorted into two major categories: (1) Comments on the costs for facilities to make a reporting determination, and (2) comments on cost estimates of labor and equipment for certain industry segments to monitor and report emissions.

Reporting Determination. Commenters stated that EPA's analysis underestimated the true compliance burden by omitting the costs for facilities to make a reporting determination—*i.e.,* estimate annual emissions to determine whether they meet the reporting threshold. These commenters recommended that EPA account for reporting determination costs incurred by both facilities that report as well as non-reporters, *i.e.,* those that monitor emissions but do not meet the reporting threshold. As discussed in Section II.F.6 of this preamble, the commenters also recommended that EPA develop screening tools to reduce the burden for facilities to make a reporting determination.

EPA agrees with commenters that the EIA would better reflect the rule's total economic burden by including all reporting determination costs. While EPA's compliance cost estimates accounted for the reporting determination burden in the proposal, it did not include the determination burden for non-reporters. Therefore, EPA has estimated the burden for reporting determinations made by non-reporters and included it in the EIA for the final rule. EPA based this estimate on the assumption that non-reporters will use a screening tool, which EPA intends to provide to facilitate reporting determinations. The estimated total cost for all non-reporters to make a reporting determination is about $18.4 million, which accounts for use of the screening tool and, if required, the cost to conduct further screening; Section 4 of the EIA provides a complete discussion of the basis for this estimate.[8] EPA expects use of the screening tool to minimize burden by allowing facilities to enter basic activity data, such as well count and drilling activity, into the tool to roughly assess whether they meet the threshold. Facilities for which the tool estimates emissions well below the threshold will generally not need to conduct further screening. Facilities for which the tool estimates emissions near the threshold will generally conduct additional screening, and this is reflected in the cost estimates.

Labor and Equipment Costs. Many commenters disagreed with EPA's cost estimates in particular segments and presented alternative estimates that in some cases differed from the agency's estimates by orders of magnitude. Many of the comments suggested that EPA's estimates of labor costs (*e.g.,* number of labor hours required to collect field data, to use equipment and engineering analysis systems to measure emissions, and to manage the emissions data) and equipment costs (*e.g.,* purchase of flow meters) were too low.

In development of this rule and in response to comments, EPA collected and evaluated cost data from multiple sources, closely reviewed the input received through public comments, and weighed the analysis prepared against this input. EPA also carefully weighed the burden of incrementally more comprehensive methods of measuring and calculating emissions against the increase in coverage and accuracy, and in some cases revised or clarified the measurement and calculation requirements. EPA has thus adjusted both the rule requirements and its cost estimates in response to comments, and concludes that its methodology and final cost estimates appropriately account for the compliance burden under this final rule. EPA determined that the commenters' alternative estimates are much higher than the agency's because of assumptions and interpretations that were either inconsistent with EPA's original intent (and which EPA has now clarified) or requirements that have been revised; in some cases, the alternative estimates were also based on higher-cost, optional monitoring methods.

EPA summarizes below the key assumptions, revisions, misinterpretations, and use of higher-cost, optional methods and the resulting costs estimates that differed most from EPA's estimates. These comments were concentrated in three industry segments: (1) Onshore production, (2) natural gas processing, and (3) natural gas distribution segments.

3. Onshore Production

Comment: Commenters stated that EPA's estimated compliance costs for the onshore petroleum and natural gas production segment were too low. Overall, the commenters concluded that EPA should reassess the analysis of entities covered by the rule, the assumptions underlying the cost estimates, and reduce the monitoring and reporting burden.

One commenter provided detailed, alternative cost estimates and concluded that costs could be as high as $1.8 billion for the onshore production segment in the first year, which is notably higher than EPA's proposal estimate of $30.4 million for this segment. The commenter made various assumptions that differed from EPA's analysis and accounted for the difference in the cost estimates. One

[8] These estimates are conservative and should be viewed as an upper-bound because the determination costs were applied at the facility-level rather than the company-level. For example, for offshore production, determination costs were applied to each of the approximately 3,000 platforms in the Gulf of Mexico rather than the 86 operators in that region. See the memo, “Estimates of Determination Costs,” in the docket for complete details and additional determination cost estimates (EPA–HQ–OAR–2009–0923).

source of the difference stemmed from the estimate of the number of sources in the onshore production segment subject to monitoring. Specifically, the commenter assumed that because the proposed rule would cover about 80 percent of emissions from the petroleum and gas industry, approximately 80 percent of the sites and equipment at each onshore production facility would be subject to the rule. The commenter therefore concluded that the rule would cover 80 percent of the 823,000 wells in the nation, or about 667,000 wells, which exceeds EPA's estimated coverage of about 467,000 wells, plus sources at non-well sites.[9] In particular, the commenter said that counting components to estimate emissions from equipment leaks would be onerous.

Additional differences in the commenter's and EPA's estimates resulted from differences in the assumptions about labor wages and time spent sampling. For example, the commenter presented a breakdown of the labor and equipment costs, such as labor wages and time spent on sampling activities. Sampling activities accounted for a notable fraction of the commenter's estimates. For example, the commenter estimated costs for sampling activity to determine the composition of produced natural gas and low pressure separator oil and to analyze all tanks for hydrocarbon liquids and produced water.

In addition, data management software constituted a substantial fraction of the commenter's total cost estimate. The commenter stated that individual reporters would spend between $100,000 and $850,000 for data management software, which totals to approximately $123 million to $1 billion for the entire segment.

EPA has carefully reviewed these comments and disagrees that the true costs will be substantially higher than those estimated by the agency.

First, EPA disagrees with the commenter's estimate of the number of sources subject to reporting because it incorrectly assumed that the proposed rule covered 80 percent of all wells in the United States. The commenter's assumption that each reporter would need to monitor 80 percent of its wells in order to report about 80 percent of its emissions implies that the type and quantity of emissions from each well are identical. This assumption, which resulted in much more labor and complex monitoring than required under the proposal, is incorrect. The quantity and type of emissions from wells are variable; in fact, it is not necessary to monitor 80 percent of wells to account for 80 percent of emissions and neither the proposed nor final rules would require such a large percentage of wells to be covered. Because the final rule tends to target those wells that have the higher emissions, based on its threshold analysis, EPA estimates that approximately 60 percent of the wells are subject to the monitoring requirements, and that these wells will account for about 85 percent of total GHG emissions from this segment.

EPA conducted the threshold analysis using actual data available through the commercial database from HPDI LLC, which collects these data primarily from individual petroleum and natural gas producing States that require petroleum and natural gas producing companies to report field data. The HPDI database includes operator well count. In most cases, HPDI provides data for each well on the production of petroleum and natural gas by operator and basin; some data are listed by property, which is a collection of wells. EPA developed a reasonable estimate of the emissions per well by apportioning the national emissions from each emissions source type to each of the wells based on the contribution of petroleum and natural gas production from each well to the national total. This analysis suggests that approximately 60 percent of the wells are owned or operated by entities that would trigger the reporting threshold, not 80 percent.

The commenter's analysis of the onshore production burden also incorrectly assumed that the rule required all onshore production reporters to spend up to $1 billion on data management software. EPA disagrees with this assumption. EPA notes that the rule does not require reporters to purchase data collection software. It is at the reporters' discretion to do so.

Although the commenter did not provide any information about the software represented in its analysis (except for cost), a system in the price range assumed by the commenter is usually customized to accommodate data needs that extend far beyond the scope of this rule. For example, such systems are typically tailored to an individual facility and used to simultaneously manage, among other things, criteria pollutants under the CAA, water discharge and permit data under the Clean Water Act, employee accident and injury reporting under Occupational Safety and Health Administration requirements, and onsite hazardous and non-hazardous solid waste information for the Resource Conservation and Recovery Act. In contrast, even the largest of reporters under this final action will be able to use standard spreadsheets or databases to collect the emissions data and perform calculations at a facility level. Spreadsheet software can store and manipulate tens of thousands of data points, and database software can store hundreds of thousands of data points. In short, spreadsheet and database software systems are capable of managing far more data than will be necessary for even the largest onshore production reporter under subpart W. Accordingly, EPA accounted for data management costs by factoring in estimates of labor to set up spreadsheets and other archiving and recordkeeping activities, as well as equipment costs like file cabinets and external hard drives; see the EIA for a complete discussion.

Another assumption contributing to the commenters' high cost estimates concerned the extent of sampling required. For example, commenters assumed that reporters would need to sample produced natural gas. EPA disagrees in part because it expects reporters to already have this information and would therefore not need to sample. In particular, producers conduct composition analysis of produced natural gas in order to pay royalties and taxes; they could use these data to estimate the percentage of GHGs instead of analyzing additional samples.

The commenters also assumed that sampling would be required for tanks and dehydrators, which resulted in cost estimates significantly higher than EPA's. Although not explicitly stated in the proposed subpart W, EPA did not intend for reporters to sample either the low pressure separator oil associated with tanks or natural gas going to dehydrators. Therefore, EPA has clarified the final rule to allow reporters that use the engineering modeling software to rely on the software's default values.

In addition, commenters also assumed that produced water and hydrocarbon liquids produced from all reporting wells in the country would have to be sampled to determine and report CO_2 content; this assumption resulted in a large sampling cost. However, EPA never intended for reporters to sample produced water and hydrocarbon liquids from all wells but instead targeted EOR operations. Therefore, EPA clarified in this final action that the sampling requirement for hydrocarbon liquids applies only to EOR operations; EPA also clarified in the final rule that

[9] Commenter estimated 823,000 wells based on a "US Energy Information Administration's 2008 report," but did not provide any other citation information.

reporting from produced water emissions sources is not required.

Finally, in response to comments about the costs to count all components to determine equipment leaks, EPA has revised the rule to require reporters to count only major equipment (*see* Section II.E of this preamble). EPA expects this revision to reduce the reporters' burden because in many cases they already have an inventory of the major equipment at each well site.

For the detailed responses to all of the comments received about the costs for onshore production, see Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems (EPA–HQ–OAR–2009–0923).

4. Natural Gas Processing

Comment: Commenters stated that EPA's estimated compliance costs for the natural gas processing segment were too low. They recommended that EPA reassess the costs for the processing segment and simplify the reporting requirements. In particular, one commenter estimated compliance costs at $4.5 billion for the processing segment. Of the $4.5 billion, the commenter attributed $3.9 billion to monitoring activities at gathering lines and boosting stations. The commenter attributed the remainder of its estimate to processing facilities.

Response: Based on its thorough review of the comments, EPA determined that the commenter's estimates for processing facilities were higher in part because it made assumptions that were inconsistent with EPA's intent. Specifically, it assumed higher-cost, optional monitoring methods for processing facilities in its analysis. However, EPA agrees with the commenter that the agency's analysis partly underestimated the costs at processing facilities to place meters on acid gas removal units. Likewise, EPA agrees that the agency's analysis did not accurately account for the compliance costs for gathering lines and boosting stations in the processing segment.

In the case of processing facilities, the commenter assumed that the rule would require reporters to install permanent flow meters, at an assumed cost of $100,000 per meter, to measure emissions from compressor venting. However, the rule does not require this and allows installation of a port for using a temporary insertion flow meter for an annual one-time estimate of vented emissions. Temporary flow meters are a significantly cheaper option than permanent meters. Based on current market data, EPA estimated approximately $1,000 for each installation of a temporary meter port for reciprocating compressors; about $5,000 for centrifugal compressors; and about $800 in capital costs for a reporter's hotwire anemometer.[10] Reporters will only need to purchase one hotwire anemometer per facility; the hotwire anemometer can be used to measure the flow rate at multiple compressors at the facility.

In addition, EPA considered and responded to the commenter's assumption about the burden to install permanent outflow meters at acid gas removal (AGR) vents. EPA incorrectly assumed that outlet meters were already installed at most sites. Specifically, EPA determined upon further analysis that the flow rates at the inlet and outlet streams for an acid gas removal unit are roughly similar. EPA therefore adjusted the calculation method in the final rule to allow the use of flow rate at the inlet or outlet, where available, based on its assumption that the outlet flow is the same as the inlet flow. In addition, if equipment to measure the flow rate, such as CEMS or a meter on the vent stack of the acid gas removal unit, is not available, the final rule allows reporters to use engineering estimates of flow rate of natural gas into the AGR. These revised requirements are reflected in the cost analysis in the final EIA.

Finally, EPA used data about the number of gathering lines and boosting stations presented by the commenter as a basis to modify the rule requirements. EPA agrees that its EIA for the proposed rule did not accurately reflect the number of gathering lines and boosting stations that would have been subject to the rule. EPA has dropped the requirement for reporting on gathering lines and boosting stations from the final rule, so these costs are not included in the analysis. Instead, EPA will continue to evaluate options for obtaining emissions data from gathering lines and boosting stations in a way that maximizes data quality while balancing industry burden; see Section II.F.1 of this preamble for further discussion.

5. Natural Gas Distribution

Comment: Commenters stated that EPA's estimated compliance costs for the natural gas distribution segment were too low by orders of magnitude. For example, one commenter estimated approximately $11.3 billion for all reporters in the natural gas distribution segment to comply with the rule. A large fraction of this estimate was based on the commenter's assumption that the leak detection requirements applied to customer meters, *i.e.,* industrial, commercial, and residential meters. The commenter did not, however, provide adequate information about the basis for the remainder of its cost estimate. In particular, the commenter stated that in addition to the costs of using an optical gas imaging instrument, each LDC would spend on average about $41 million annually to comply with the rule, but did not specify any compliance activities that accounted for the $41 million.

Response: EPA has carefully reviewed these comments and disagrees that the agency's cost estimates should be orders of magnitude higher. EPA has determined that commenters' interpretations of the proposed rule were inconsistent with the Agency's intent and this likely accounted for the discrepancies between the estimates.

EPA disagrees with the commenter's cost estimate because it is based on the assumption that customer meters are subject to leak detection requirements. The commenter assumed that the proposed rule required leak detection and emissions estimates for all customer meters, *i.e.,* industrial, commercial, and residential meters; the commenter estimated reporters would spend approximately $5.4 billion to monitor these meters. EPA never intended to require reporting for customer meters, which would involve a major cost and have minimal effect on the quality of emissions estimates. EPA has therefore clarified the final rule to note that sources subject to reporting in the natural gas distribution segment do not include customer meters for natural gas.

In addition, EPA has responded to the commenter's recommendation to reduce the compliance costs by simplifying the requirements for optical gas imaging instrument equipment, *e.g.,* allowing alternatives to infrared cameras in some situations. As discussed previously in Section II.E of this preamble, this final action provides more flexibility and further reduces the compliance cost by allowing facilities to use alternative leak detection equipment.

The commenter did not identify the monitoring activities and assumptions underlying its estimate of $5.9 billion to comply with leak detection requirements. The commenter noted that it obtained the estimate from an informal survey of its members but did not provide sufficient information or documentation substantiating what was included in this estimate. Because EPA has accounted for the two primary issues raised by the commenter (monitoring of customer meters and allowable leak detection equipment),

[10] For example, see *Global Water Instrumentation Inc.,* at *http://www.globalw.com/products/407119.html.*

EPA did not change its cost estimate to reflect the much higher costs estimated by the commenter.

C. What are the economic impacts of the rule?

1. Summary of Economic Impacts

EPA prepared an economic impact analysis to evaluate the impacts of the rule on affected small and large reporting entities.

To estimate the economic impacts of the rule, EPA first conducted a screening assessment, comparing the estimated total annualized compliance costs for the petroleum and gas industry, where industry is defined in terms of North American Industry Classification System (NAICS) code, with industry average revenues.[11] The national costs of the rule are notable because there are a large number of affected entities, but per-entity costs are low. Average cost-to-sales ratios for establishments in the affected NAICS codes for all segments is less than 1 percent, except in the 1–20 employee range for the onshore petroleum and natural gas segment.

These low average cost-to-sales ratios indicate that the final rule is unlikely to result in significant changes in firms' production decisions or other behavioral changes that would result in significant changes in prices or quantities in affected markets. Given that prices and quantities are unlikely to change significantly, and consistent with the agency's guidelines for economic analyses, EPA used the engineering cost estimates to measure the social cost of the rule, rather than modeling market responses and using the resulting measures of social cost.[12] Table 8 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE 8—ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES

(Year 1)

NAICS	NAICS Description	MRR Segments included	Average cost per entity ($1,000/entity)	Average entity cost-to-sales ratio [a] (percent)
211	Crude Petroleum and Natural Gas Extraction.	Onshore Production, Offshore Production, Processing.	$17.1	0.08
486210	Pipeline Transportation of Natural Gas	Transmission, Underground Storage, LNG Storage, and LNG Import Terminals.	15.7	0.08
221210	Natural Gas Distribution	Distribution	13.9	0.06

[a] This ratio reflects first year costs. Subsequent year costs will be lower because they do not include initial start-up activities.

2. Summary of Comments and Responses

While EPA received a substantial number of comments on the estimated costs for reporters to comply with the rule, there were minimal additional comments on the economic impacts, such as changes in production or effects on small entities in particular. As discussed in the previous section of this preamble, commenters said that EPA underestimated the compliance costs and recommended that EPA carefully review the economic impact analysis. See the previous section of this preamble for a summary; the response to comments document, Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, provides detailed comments.

As discussed in Section III.B.2 of this preamble, EPA collected and evaluated cost data from multiple sources, thoroughly reviewed the input received through public comments, and weighed the analysis prepared for the proposal against this input. EPA has determined that this analysis provides a reasonable characterization of costs and economic impacts and that the documentation provides adequate explanation of how the costs and impacts were estimated.

D. What are the impacts of the rule on small businesses?

1. Summary of Impacts on Small Businesses

As required by the RFA and Small Business Regulatory Enforcement and Fairness ACT (SBREFA), EPA assessed the potential impacts of the rule on small entities (small businesses, governments, and non-profit organizations). (*See* Section IV.C of this preamble for definitions of small entities.)

EPA has determined the selected threshold maximizes the rule coverage with 85 percent of U.S. GHG emissions from the industry segments reported by approximately 2,786 reporters, while keeping reporting burden to a minimum. Furthermore, many industry stakeholders that EPA met with expressed support for a 25,000 metric ton CO_2e threshold because it sufficiently captures the majority of GHG emissions in the United States, while excluding many of the smaller facilities and sources. In response to the comments EPA received about the monitoring and reporting requirements in specific source categories, EPA incorporated changes that reduce burden on reporters while maintaining a high level of emissions coverage. For information on these issues, refer to the discussion of each segment in this preamble.

EPA conducted a screening assessment comparing compliance costs to onshore petroleum and natural gas industry specific receipts data for establishments owned by small businesses. This ratio constitutes a "sales" test that computes the annualized compliance costs of this rule as a percentage of sales and determines whether the ratio exceeds one percent.[13] The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed EPA to account for receipt differences between establishments owned by large and small businesses and differences in small business definitions across affected industries. The results of the screening assessment are shown in Table 9 of this preamble.

[11] **Note:** Before totaling the industry compliance costs, EPA estimated costs for each of the industry segments. EPA then summed the costs for each segment at the NAICS level for this screening assessment.

[12] Guidelines for Preparing Economic Analyses (EPA, 2002, p. 124–125).

[13] EPA's RFA guidance for rule writers suggests the "sales" test continues to be the preferred quantitative metric for economic impact screening analysis.

TABLE 9—ESTIMATED COST-TO-SALES RATIOS, SALES RECEIPTS ($MILLION), AND NUMBER OF ESTABLISHMENTS FOR FIRST YEAR COSTS BY INDUSTRY AND ENTERPRISE SIZE[a]

Industry	NAICS	NAICS Description	SBA Size standard in num of employees (effective March 11, 2008)	Average cost per entity ($1,000/entity)	All enterprises	Owned by enterprises with:						
						1 to 20 Employees	20 to 99 Employees	100 to 499 Employees	<500 Employees	500 to 749 Employees	750 to 999 Employees	1,000 to 1,499 Employees
Onshore petroleum and natural gas production; offshore petroleum and natural gas production; LNG storage; LNG import and export.	211	Crude Petroleum and Natural Gas Extraction.	500	$17.1	0.08% [d]$160,879 [e]7,629	1.32% $7,573 5,836	0.11% $6,790 456	0.05% $9,609 292	0.47% $23,972 6,584	0.47% $4,609 60	0.03% $3,991 64	0.02% $2,805 31
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage.	486210	Pipeline Transportation of Natural Gas.	(b)	$15.7	0.08% [d]$35,897 [e]1,936	0.12% $1,035 81	0.40% [c]$106 27	0.24% [c]$394 61	0.10% $2,566 36	(c) (c) 169	(c) (c) 2	(c) (c) 20
Natural gas distribution	221210	Natural Gas Distribution	500	$13.9	0.06% [d]$67,275 [e]2,897	0.27% $2,524 483	0.03% $4,642 86	0.06% $2,878 131	0.11% $13,127 700	0.07% $865 68	0.02% $2,116 33	0.03% $3,757 73

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

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

[b] The SBA size standard for NAICS 486210 is $7 million in average annual receipts.

[c] The U.S. Census Bureau has missing data for this employee range; some estimates were possible using partial data. The receipts for these categories underestimate true value.

[d] This row presents total annual sales receipts ($Million)for establishments in each enterprise category. Source: U.S. Census Bureau.

[e] This row presents total number of establishments in each enterprise category. Source: U.S. Census Bureau.

As shown, the cost-to-sales ratios are less than one percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program. The only exception is the ratio for enterprises with 1–20 employees for crude petroleum and natural gas extraction, which is greater than 1 percent but less than 2 percent. It is important to note that this analysis does not screen out entities that would be below the reporting threshold. Based on further analysis of production data in HPDI, EPA estimates that in most cases, the smaller enterprises have very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e reporting threshold.

In other cases, a small enterprise (less than 20 employees) may own large operations but conduct nearly all of its operations through service providers, so that it has few employees of its own. Such enterprises, however, tend to have higher annual revenues than those with small operations and therefore have lower cost-to-sales ratios. The review of production data by operator in HPDI shows a ratio of less than one percent for the operators expected to meet the reporting threshold.

EPA took a conservative approach with the model entity analysis. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a model establishment within several enterprise size ranges. That is, the analysis assumes that each establishment is a unique enterprise. To the extent that a single parent may own multiple establishments, the small entity impacts could be lower.

Although this rule will not have a significant economic impact on a substantial number of small entities, the Agency nonetheless tried to reduce the impact of this rule on small entities, including seeking input from a wide range of private- and public-sector stakeholders. When developing the rule, the Agency took special steps to ensure that the burdens imposed on small entities were minimal. The Agency conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. The Agency investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. The Agency also established a reasonable balance of direct measurement, engineering estimation, and emission factors based monitoring methods to quantify emissions, which provides flexibility to entities and helps minimize reporting costs.

2. Summary of Comments and Responses

Comment: Some commenters noted concerns about the rule's impact on small businesses, in particular that small businesses would have to apply the monitoring methods specified in the rule to determine whether they have to report under the rule. One commenter recommended that EPA redo its analysis of the rule's impacts on small businesses using "more accurate economic impact data," but did not include or identify alternative data sources for such an analysis. See the response to comments document, Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, for the detailed comments.

Response: EPA has assessed the economic impact of the final rule on small entities and concluded that this action will not have a significant economic impact on a substantial number of small entities. While the commenter did not provide details in its recommendation that EPA redo the small business analysis using "more accurate economic impact data," EPA acknowledges the importance of using the best available economic data. Accordingly, EPA analyzed the economic impact on small entities using the revised cost estimates discussed in this section of the preamble and in the EIA. These cost estimates were the same order of magnitude as those estimated under the proposal; the estimates also reflected improvements made in response to comments as well as changes to the monitoring requirements in the final rule.

In addition, EPA's assessment of the economic impacts on small entities continued to rely on data from the Statistics of U.S. Businesses, a well-known database that provides national information on the distribution of economic variables by the size of entity. As noted in the EIA, these data were developed in cooperation with, and partially funded by, the Office of Advocacy of the Small Business Administration. Complete documentation of this analysis can be found in Section 5.2 of the EIA for the final rule.

Finally, in response to concerns about the cost to make a reporting determination, EPA intends to provide screening tools. As discussed above, these tools will aid small businesses and other potential reporters in determining whether or not they have to report.

The response to comments document, Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, presents the detailed comments and responses related to the rule's impact on small businesses.

E. What are the benefits of the rule for society?

EPA examined the potential benefits of the final subpart W. The benefits of a reporting system are based on their relevance to policy making, transparency, and market efficiency. Benefits are very difficult to quantify and monetize. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

A mandatory reporting system for petroleum and natural gas systems will benefit policymakers and the public by increased availability of facility emissions data. Public data on emissions allows for accountability of emitters to the public. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with emitters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers. Facility-specific emissions data will also aid local, State, and national policymakers as they evaluate and consider future climate change policy decisions.

The benefits of mandatory reporting of petroleum and natural gas systems GHG emissions to government also include enhancing existing programs, such as the Natural Gas STAR Program, and that provide significant benefits. Through the Natural Gas STAR Program, EPA has identified over 120 proven, cost effective technologies and practices to reduce emissions of methane—the primary constituent of natural gas—from operations in all of the major industry sectors—production, gathering and processing, transmission, and distribution. The final subpart W will increase knowledge of the location and magnitude of significant methane emissions sources in the petroleum and natural gas industry, which can result in improvements in these technologies and the identification of new emissions reducing technologies.

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

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

The EIA for this final rule as well as the RIA for 40 CFR part 98 summarize the anticipated benefits, which include providing the government with sound data on which to base future policies and providing industry and the public independently verified information documenting firms' environmental performance. While EPA has not quantified the benefits of the mandatory reporting rule, EPA believes that they are substantial and justify the estimated costs.

IV. Statutory and Executive Order Review

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2376.02.

EPA plans to collect complete and accurate facility-level GHG emissions from the petroleum and natural gas industry. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of different segments of the petroleum and natural gas industry and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from facilities within the petroleum and natural gas industry over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which segments of the petroleum and gas industry would be affected, and how these segments would be affected by the options.

This information collection is mandatory and will be carried out under CAA section 114. Information identified and marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. However, emissions data collected under CAA section 114 cannot generally be claimed as CBI and will be made public.

The projected cost and hour burden for non-Federal respondents is $27.7 million and 396,474 hours per year. The estimated average burden per response is 90.71 hours; the frequency of response is annual for all respondents that must comply with the final rule's reporting requirements; and the estimated average number of likely respondents per year is 2,786. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (averaging $0.74 million), a total operation and maintenance component (averaging $1.7 million per year), and a labor cost component (averaging $25.3 million per year).[14]

Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the EIA for these subparts because the information collection request (ICR) costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the EIA for the subparts for the first year of the rule and for subsequent years of the rule. In addition, the ICR focuses on respondent burden, while the EIA includes both national compliance costs and the burden for EPA to implement the rule.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The small entities directly regulated by this final rule include small businesses in the petroleum and gas industry, small governmental jurisdictions and small non-profits. EPA has determined that some small businesses will be affected because their production processes emit GHGs exceeding the reporting threshold.

For affected small entities, EPA conducted a screening assessment comparing compliance costs for affected industry segments to petroleum and gas-specific data on revenues for small

[14] Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the Economic Analysis because the ICR costs represent the average cost over the first three years of the proposed rule, but costs are reported elsewhere in the Economic Analysis for the first year of the proposed rule and for subsequent years of the proposed rule. In addition, the ICR focuses on respondent burden, while the Economic Analysis includes EPA Agency costs.

businesses. This ratio constitutes a "sales" test that computes the annualized compliance costs of this final rule as a percentage of sales and determines whether the ratio exceeds some level (*e.g.,* 1 percent or 3 percent). The cost-to-sales ratios were constructed at the establishment level (average compliance cost for the establishment/average establishment revenues).

As shown in Table 9 of this preamble, the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1 percent for industries presumed likely to have small businesses covered by the reporting program. It is important to note that this analysis does not screen out entities that would be below the reporting threshold. Although the costs to receipts for entities in onshore production with 1–20 employees is slightly over 1 percent, most of these facilities would likely not exceed the 25,000 mtCO_2e threshold, a threshold supported by many stakeholders as one that sufficiently captures the majority of GHG emissions while excluding small facilities.

EPA also concluded that the final rulemaking would not affect a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field. Specifically, the data listing entities in each segment of the petroleum and natural gas industry did not include any non-profit entities.

In addition, EPA determined that the final rulemaking would not have a significant impact on small governmental jurisdictions. EPA determined that one segment of the petroleum and natural gas industry might include small governments affected by the final rulemaking. A comparison of the compliance costs to the revenue of potentially affected small governmental jurisdictions revealed that the costs of the rule are less than 1 percent of revenues.

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this final rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA allows different monitoring methods for different emissions sources, requiring direct measurement only for selected sources. Also, EPA intends to provide a screening tool that will help small businesses make a reporting determination (*see* Section II.F.6 of this preamble). Finally, EPA is establishing annual instead of more frequent reporting.

Through comprehensive outreach activities prior to proposal of the initial rule, EPA held approximately 100 meetings and/or conference calls with representatives of the primary audience groups, including numerous trade associations and industries in the petroleum and gas industry that include small business members. EPA's outreach activities prior to proposal of the initial rule are documented in the memorandum, Summary of EPA Outreach Activities for Developing the Greenhouse Gas Reporting Rule, located in Docket No. EPA–HQ–OAR–2008–0508–053. After the initial proposal, EPA posted a guide for small businesses on the EPA GHG reporting rule website, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline to answer questions about the final rule. EPA continued to meet with stakeholders and entered documentation of all meetings into the docket.

During rule implementation, EPA would maintain an "open door" policy for stakeholders to ask questions about the final rule or provide suggestions to EPA about the types of compliance assistance that would be useful to small businesses. EPA intends to develop a range of compliance assistance tools and materials and conduct extensive outreach for the final rule.

EPA has therefore concluded that this final action will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. EPA estimated the cost to individual facilities that may have to report to this final rule using actual facility characteristics such as throughput and size. EPA also determined the costs to non-reporters for determination to report. The sum of these costs for the entire industry has been estimated to be less than $100 million. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Based on EPA's analysis of the rule's impact on small entities, the Agency determined that natural gas distribution is the only industry segment that would potentially have small governments affected by the rule. In this segment, however, the facilities owned or operated by small governments are expected to be too small to trigger the 25,000 metric tons CO_2e reporting threshold.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. This regulation applies directly to petroleum and natural gas facilities that emit greenhouse gases. Few, if any, State or local government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. EPA conducted an analysis to determine potential impact of this action on tribes that own or operate petroleum and natural gas systems (EPA–HQ–OAR–2009–0923–XXX). First, EPA analyzed a comprehensive listing of all operators of petroleum and natural gas systems in the United States in conducting the threshold analysis. In a separate analysis, EPA researched additional available data to determine which tribal entities may own or operate petroleum and natural gas systems that could be impacted by this final action. As a result of those analyses, EPA found one tribe that may potentially be impacted by this final action. Finally, during the comment period for the April 2010 proposal, EPA received comment from one tribe, Southern Ute, which were specific to the proposed reporting methodologies.

As further discussed in the 2009 final rule that established the Greenhouse Gas reporting program, EPA believes that there are minimal impacts to tribes. Tribes could be required to submit an annual GHG report for any facility they own or operate that is subject to the rule. Specifically, tribes that own or operate oil and gas operations could be required to report emissions under this rulemaking. It should be noted that the owner or operator of any privately owned sources located on a reservation would be required to report for any applicable facility. EPA sought opportunities to provide information to tribal governments and representatives during rule development. As stated in IV.F of this preamble, Executive Order 13175: Consultation and Coordination with Indian Tribal Governments of 40 CFR part 98, and in consultation with EPA's American Indian Environment Office, EPA's outreach plan for the Greenhouse Gas Reporting Rule included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase of part 98. For example, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of The Climate Registry (TCR).

In addition, EPA prepared a short article on the Greenhouse Gas Reporting Program that appeared on the front page of a Tribal newsletter—Tribal Air News—that was distributed to EPA/OAQPS's network of Tribal organizations. EPA gave a presentation on various climate efforts, including the Greenhouse Gas Reporting Program, at the National Tribal Conference on Environmental Management on June 24–26, 2008. In addition, EPA distributed copies of a short information sheet at a meeting of the National Tribal Caucus. See the Summary of EPA Outreach Activities for Developing the GHG reporting rule, in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of Tribal contacts. EPA participated in a conference call with Tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the final Part 98. It was posted on the Greenhouse Gas Reporting Program Web site and published in the Tribal Air Newsletter.

As required by section 7(a), EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

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

This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. Also, this is not an economically significant rule under EO 12866, and thus EO 13045 does not apply.

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

This final rule is not a "significant energy action" as defined in EO 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, EPA has concluded that this final rule is not likely to have any adverse energy effects. This final rule relates to monitoring, reporting and recordkeeping at petroleum and gas facilities that emit over 25,000 $mtCO_2e$ and does not impact energy supply, distribution or use. Therefore, EPA concludes that this final rule is not likely to have any adverse effects on energy supply, distribution, or use.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA provides the flexibility to use any one of the voluntary consensus standards from at least seven different voluntary consensus standards bodies, including the following: ASTM, ASME, ISO, Gas Processors Association, and American Gas Association. These voluntary consensus standards will help facilities monitor, report, and keep records of greenhouse gas emissions. No new test methods were developed for this final rule. Instead, EPA reviewed existing rules for source categories and voluntary greenhouse gas programs and identified existing means of monitoring, reporting, and keeping records of greenhouse gas emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products.

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

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

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

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

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective December 30, 2010.

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Incorporation by reference, Suppliers, Reporting and recordkeeping requirements.

Dated: November 8, 2010.

Lisa P. Jackson,

Administrator.

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

PART 98—[AMENDED]

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

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 2. Section 98.2 is amended by revising the introductory text to paragraph (a) to read as follows:

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States or under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331) and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

* * * * *

■ 3. Section 98.6 is amended by adding the following definitions in alphabetical order and revising the definition of "United States" to read as follows:

§ 98.6 Definitions.

* * * * *

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

* * * * *

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

* * * * *

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

* * * * *

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

* * * * *

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seal emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing vent emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

* * * * *

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (*e.g.* level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

* * * * *

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

* * * * *

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (*e.g.,* ethane, propane, butane, pentane-plus) in feed natural gas stream.

* * * * *

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

* * * * *

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

* * * * *

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

* * * * *

High-bleed pneumatic devices are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

* * * * *

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

* * * * *

Low-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

* * * * *

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

* * * * *

Outer Continental Shelf means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. 1331, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

* * * * *

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas or CO_2 by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO_2 that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

* * * * *

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

* * * * *

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide (H_2S)and/or carbon dioxide (CO_2) that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

* * * * *

Sweet gas is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

* * * * *

United States means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

* * * * *

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

* * * * *

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (*i.e.* well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas."

* * * * *

■ 4. Section 98.7 is amended by adding and reserving paragraphs (n) and (o), and by adding paragraphs (p) and (q) to read as follows:

§ 98.7 What standardized methods are incorporated by reference into this part?

* * * * *

(n) [Reserved]

(o) [Reserved]

(p) The following material is available for purchase from the American Association of Petroleum Geologists, 1444 South Boulder Avenue, Tulsa, Oklahoma 74119, (918) 584–2555, *http://www.aapg.org.*

(1) Geologic Note: AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991), pages 1644–1651, IBR approved for § 98.238.

(2) Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in cooperation with the USGS, 1978, IBR approved for § 98.238.

(q) The following material is available from the Energy Information Administration (EIA), 1000 Independence Ave., SW., Washington, DC 20585, (202) 586–8800, *http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/field_code_master_list/current/pdf/fcml_all.pdf.*

(1) Oil and Gas Field Code Master List 2008, DOE/EIA0370(08), January 2009, IBR approved for § 98.238.

(2) [Reserved]

■ 5. Table A–4 to subpart A is amended by adding an entry for "Petroleum and Natural Gas Systems (subpart W)" at the end of the table to read as follows:

TABLE A–4 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(A)(2)

Source Categories[a] Applicable in 2010 and Future Years
* * * * * * *
Additional Source Categories[a] Applicable in 2011 and Future Years
* * * * * * *
Petroleum and Natural Gas Systems (subpart W)

[a] Source categories are defined in each applicable subpart.

■ 6. Add Subpart W—Petroleum and Natural Gas Systems to read as follows:

Subpart W—Petroleum and Natural Gas Systems

§ 98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well pad or associated with a well pad (including compressors, generators, or storage facilities), and portable non-self-propelled equipment on a well pad or associated with a well pad (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2, and all petroleum and natural gas production located on islands, artificial islands, or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing.* Natural gas processing separates and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes:

(i) All processing facilities that fractionate.

(ii) All processing facilities that do not fractionate with throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include reporting of emissions from gathering lines and boosting stations—these sources are currently not covered by subpart W.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines (not interstate transmission pipelines or intrastate transmission pipelines) and metering and regulating equipment at city gate stations, and excluding customer meters, that physically deliver natural gas to end users and is operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment excludes customer meters and infrastructure and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and "farm taps" upstream of the local distribution company inlet.

(b) [Reserved]

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2). Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in paragraph § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in § 98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a well pad or associated with a well pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Gas well venting during well completions with hydraulic fracturing.

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Gas well venting during well workovers with hydraulic fracturing.

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production well pad. Stationary or portable equipment are the following equipment which are integral to the extraction, processing or movement of oil or natural gas: Well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report emissions from the following sources:

(1) Above ground meters and regulators at custody transfer city gate stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded.

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded.

(3) Below ground meters and regulators and vault equipment leaks. Customer meters are excluded.

(4) Pipeline main equipment leaks.

(5) Service line equipment leaks.

(6) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

(j) All applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-1)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from a natural gas pneumatic device vent, for GHG i.

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section.

EF = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHG_i equals 1.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-2)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from all natural gas pneumatic pump venting, for GHG i.

Count = Total number of natural gas pneumatic pumps.

EF = Population emission factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHG_i = Concentration of GHG i, CH_4 or CO_2, in produced natural gas.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (*e.g.* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If CEMS and/or volumetric flow rate monitor are not available, you may install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(2) *Calculation Methodology 2.* If CEMS is not available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \quad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b).

Vol_{CO2} = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If using CEMS or vent meter is not an option, use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation W–4 of this section.

$$E_{a,CO2} = \left(V + \alpha * \left(V * \left(Vol_I - Vol_O\right)\right)\right) * \left(Vol_I - Vol_O\right) \qquad \text{(Eq. W-4)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* Calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(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.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in § 98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in § 98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in § 98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2 and N_2O (when flared) emissions using calculation methodologies described in paragraphs (e)(1) or (e)(2) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(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 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 and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(2)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b)(1) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with throughput less than 0.4 million cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 74.5 for CH_4 and 3.26 for CO_2 at 68°F and 14.7 psia or 73.4 for CH_4 and 3.21 for CO_2 at 60°F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million cubic feet.

1000 = Conversion of EF_i in thousand standard cubic to cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H*D^2*P*P_2*\%G*365days/yr)}{(4*P_1*T*1{,}000cf/Mcf*100)} \quad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia).
P = pi (3.14).
%G = Percent of packed vessel volume that is gas.
T = Time between refilling (days).
100 = Conversion of %G to fraction.

(6) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For one well of each unique well tubing diameter and producing horizon/formation combination in each gas producing field (see § 98.238 for the definition of Field) where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (*e.g.* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

$$E_{a,n} = \sum_h \sum_t T_{h,t} * FR_{h,t} \quad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions in cubic feet.
$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.
$FR_{h,t}$ = Average flow rate in cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded time of one representative well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting for liquids unloading using Equation W–8 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*CD^2*WD*SP*N_V\}+\{SFR*(HR-1.0)*Z\} \quad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD = Casing diameter (inches).
WD = Well depth to first producing horizon (feet).
SP = Shut-in pressure (psia).
N_V = Number of vents per year.
SFR = Average sales flow rate of gas well in cubic feet per hour.
HR = Hours that the well was left open to the atmosphere during unloading.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
Z = If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*TD^2*WD*SP*N_V\}+\{SFR*(HR-0.5)*Z\} \quad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD = Tubing diameter (inches).

WD = Tubing depth to plunger bumper (feet).

SP = Sales line pressure (psia).

N_V = Number of vents per year.

SFR = Average sales flow rate of gas well in cubic feet per hour.

HR = Hours that the well was left open to the atmosphere during unloading.

0.5 = Hours for average well to blowdown tubing volume at sales line pressure.

Z = If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10 of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{a,n} = (T * FR) - EnF - SG \quad \text{(Eq. W-10)}$$

Where:

$E_{a,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions following hydraulic fracturing.

T = Cumulative amount of time in hours of all well completion venting in a field during the year reporting.

FR = Average flow rate in cubic feet per hour, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.

SG = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section.

(i) *Calculation Methodology 1.* For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in § 98.234(b).

(A) The average flow rate in cubic feet per hour of venting to the atmosphere or routed to a flare is determined from the flow recording over the period of backflow venting.

(B) The respective flow rates are applied to all well completions in the producing field and to all well workovers in the producing field for the total number of hours of venting of each of these wells.

(C) New flow rates for completions and workovers are measured every other calendar year for each reporting gas producing field and gas producing geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(ii) *Calculation Methodology 2.* For one well completion in each gas producing field and for one well workover in each gas producing field, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W–11 of this section for subsonic flow or Equation W–12 of this section for sonic flow:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \quad \text{(Eq. W-11)}$$

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-12)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

(A) The average flow rate in cubic feet per hour of venting across the choke is calculated for one well completion in each gas producing field and for one well workover in each gas producing field by averaging the gas flow rates during venting to the atmosphere or routing to a flare.

(B) The respective flow rates are applied to all well completions in the gas producing field and to all well workovers in the gas producing field for the total number of hours of venting of each of these wells.

(C) Flow rates for completions and workovers in each field shall be calculated once every two years for each reporting gas producing field and geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) The volume of recovered completion gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (*e.g.* reduced emissions completion).

(i) Use the factor SG in Equation W–10 of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]

(6) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing and well workovers not involving hydraulic fracturing using Equation W–13 of this section:

$$E_{a,n} = N_{wo} * EF_{wo} + \sum_f V_f * T_f \qquad \text{(Eq. W-13)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per field not involving hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in actual cubic feet per workover. EF_{wo} = 2,454 standard cubic feet per well workover without hydraulic fracturing.

f = Total number of well completions without hydraulic fracturing in a field.

V_f = Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

(1) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 50 standard cubic feet, retain logs of the number of blowdowns for each equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 50 standard cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation W–14 of this section:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s} \right) - V_v * C \right) \qquad \text{(Eq. W-14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.

V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual conditions in the blowdown equipment chamber (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation W–14 and paragraph (i)(4) of this section.

(j) *Onshore production storage tanks.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with oil throughput greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1)(viii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the field.

(C) Analyze a representative sample of separator oil in each field for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b)(1) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the field and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W–15 of this section:

$$E_{s,i} = EF_i * Count \quad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Populations emission factor for separators and wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.3 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia, and for gas condensate use 17.8 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia.

Count = Total number of separators and wells with throughput less than 10 barrels per day.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i} = (CF_n * E_n * T_n) + (E_t * (8760 - T_n)) \quad \text{(Eq. W-16)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 5 in paragraphs (j)(1) through (j)(5) of this section (with wellhead separators) during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 3 in paragraphs (j)(1) through (j)(5) of this section at maintenance or operations during the time the dump valve is closing properly (ie. $8760 - T_n$) in cubic feet per hour.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For condensate storage tanks, either water or hydrocarbon, without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify emissions:

(i) Use a meter, such as a turbine meter, to estimate tank vapor volumes according to methods set forth in § 98.234(b). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(l) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–17 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the well being tested.

D = Number of days during the year, the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–18 of this section.

$$E_{a,n} = GOR * V \quad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Volume of oil produced in barrels in the calendar year during which associated gas was vented or flared.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}\,(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}\,(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{(Eq. W-21)}$$

Where:

E_{a,CH_4}(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH_4 in gas to the flare.

X_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W–40, Equation W–19, Equation W–20 and Equation W–21 of this section.

(8) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(9) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by § 98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents)

including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \quad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8),GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-24)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG $_i$. Use 12.2 million standard cubic feet per year per compressor for CH_4 and 538 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 12 million standard cubic feet per year per compressor for CH_4 and 530 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in § 98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in § 98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W–28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowndown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG i. Use 9.63 thousand standard cubic feet per year per compressor for CH_4 and 0.535 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 9.48 thousand standard cubic feet per year per compressor for CH_4 and 0.527 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all sources listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate emissions using Equation W–30 of this section for each source with equipment leaks.

$$E_{s,i} = GHG_i * \sum_x EF_s * T_x \quad \text{(Eq. W-30)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

x = Total number of this type of emissions source found to be leaking during T_x.

EF_s = Leaker emission factor for specific sources listed in Table W–2 through Table W–7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_x = The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4) and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. Average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

EF_s = Population emission factor for the specific source, s listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for non-custody transfer city gate stations is determined in Equation W–32.

GHG_i = For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_s = Total time the specific source s associated with the equipment leak emission was operational in the calendar year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1–A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1–A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed in § 98.232(i)(2), shall use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section to develop facility emission factors using Equation W–32 of this section. The calculated facility emission factor from Equation W–32 of this section shall be used in Equation W–31 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \quad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in cubic feet per meter per year.

$E_{s,i}$ = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (q) of this section.

Count = Total number of meter runs at all above grade M&R city gate stations at custody transfer.

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas using Equation W–33 of this section.

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation W–34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(v) GHG mole fraction in natural gas stored in LNG storage facilities.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W–36 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \quad \text{(Eq. W-36)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0538 kg/ft³ for CO_2 and N_2O, and 0.0196 kg/ft³ for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft³ for CO_2 and N_2O, and 0.0193 kg/ft³ for CH_4 at 60°F and 14.7 psia.

GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W–37 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. W-37)}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft³. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

$$Mass_{s,CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2 CH_4 and N_2O combustion-related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend of fuels listed in Table C–1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources). If the fuel combusted is natural gas and is pipeline quality and has a minimum high heat value of 950 Btu per standard cubic foot, then the natural gas emission factor and high heat values listed in Tables C–1 and C–2 of this part may be used.

(2) For fuel combustion units that combust field gas or process vent gas, or any blend of field gas or process vent gas and fuels listed in Table C–1 of subpart C of this part, calculate combustion emissions as follows:

(i) If you have a continuous flow meter on the combustion unit, you must use the measured flow volumes to calculate the total flow of gas to the unit. If you do not have a permanent flow meter on the combustion unit, you may install a permanent flow meter on the combustion unit, or use company records or engineering calculations based on best available data on heat duty or horsepower to estimate volumetric unit gas flow.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39 of this section.

$$E_{a,CO2} = \sum_j V_a * Y_j * R_j \quad \text{(Eq. W-39)}$$

Where:

E_{a,CO_2} = Contribution of annual emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_j = Concentration of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j;* 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions. You must report the type and number of each external fuel combustion unit.

(4) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(6) Calculate N_2O mass emissions using Equation W–40 of this section.

$$N_2O = \left(1 \times 10^3\right) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

Where:

N_2O = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (z)(8)(i), (z)(8)(ii) or (z)(8)(iii) of this section (units must be consistent with Fuel).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) For fuels listed in Table C–1 of subpart C of this part, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

(iii) For fuels not listed in Table C–1 of subpart C of this part and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in subpart C of this part to determine HHV.

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18(i)(1) and (2) of the *Alternative work practice for monitoring equipment leaks.* Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) *Optical gas imaging instrument.* An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed 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. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak 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 use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(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.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W–41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-41)}$$

Where:

p = Absolute pressure.
R = Universal gas constant.
T = Absolute temperature.
V_m = Molar volume.

$$= \frac{0.45724 R^2 T_c^2}{p_c}$$

$$= \frac{0.7780 R T_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

Where:

ω = Acentric factor of the species.
T_c = Critical temperature.
P_c = Critical pressure.

(f) Special reporting provisions

(1) *Best available monitoring methods.* EPA will allow owners or operators to use best available monitoring methods for parameters in § 98.233 Calculating GHG Emissions as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered. EPA reserves the right to review petitions after the deadline but will only consider and approve late petitions which demonstrate extreme or unusual circumstances. The Administrator reserves to right to request further information in regard to all petition requests. The owner or operator must use the calculation methodologies and equations in § 98.233 Calculating GHG Emissions. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related emissions.* During January 1, 2011 through June 30, 2011, owners or operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart, and only where required measurements cannot be duplicated due to technical limitations after June 30, 2011. These well-related sources are:

(i) Gas well venting during well completions and workovers with hydraulic fracturing as specified in § 98.233(g).

(ii) Well testing venting and flaring as specified in § 98.233(l).

(3) *Best available monitoring methods for specified activity data.* During January 1, 2011 through June 30, 2011, owners or operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart, specifically for events that generate data that can be collected only between January 1, 2011 and June 30, 2011 and cannot be duplicated after June 30, 2011. These sources are:

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (f), (g), (h), (l), (o), (p), (q), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(f), (g), (h), (i), and (w).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z).

(4) *Best available monitoring methods for leak detection and measurement.* The owner or operator may request use of best available monitoring methods between January 1, 2011 and December 31, 2011 for sources requiring leak detection and/or measurement. These sources include:

(i) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(ii) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(iii) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in § 98.232(c)(17) and (d)(6).

(iv) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1).

(v) Condensate (oil and/or water) storage tanks in onshore natural gas transmission compression as specified in § 98.232(e)(3).

(5) *Requests for the use of best available monitoring methods.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods.

(i) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and June 30, 2011 for the sources specified in paragraph (f)(2) of this section.

(ii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and June 30, 2011 for the sources specified in paragraph (f)(3) of this section.

(iii) Owners or operators must submit a request and receive approval by the Administrator to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(4) of this section.

(A) *Timing of request.* The request to use best available monitoring methods for paragraph (f)(4) of this section must be submitted to EPA no later than April 30, 2011.

(B) *Content of request.* Requests must contain the following information for sources listed in paragraph (f)(4) of this section:

(*1*) A list of specific source types and specific equipment, monitoring instrumentation, and/or services for which the request is being made and the locations where each piece of monitoring instrumentation will be installed or monitoring service will be supplied.

(*2*) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the instrumentation or monitoring service is needed.

(*3*) Documentation which demonstrates that the owner or operator made all reasonable efforts to obtain the information, services or equipment necessary to comply with subpart W reporting requirements, including evidence of specific service or equipment providers contacted and why services or information could not be obtained during 2011.

(*4*) A description of the specific actions the facility will take to obtain and/or install the equipment or obtain the monitoring service as soon as reasonably feasible and the expected date by which the equipment will be obtained and operating or service will be provided.

(C) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it does not own the required monitoring equipment, and it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment or to obtain leak detection or measurement services in order to meet the requirements of this subpart for 2011.

(iv) EPA does not anticipate a need to approve the use of best available monitoring methods for sources not listed in paragraphs(f)(2), (f)(3), and (f)(4) of this section; however, EPA will review such requests if submitted in accordance with paragraph (f)(5)(iv)(A)–(C) of this section.

(A) *Timing of request.* The request to use best available monitoring methods for sources not listed in paragraphs (f)(2), (f)(3), and (f)(4) of this section must be submitted to EPA no later than April 30, 2011.

(B) *Content of request.* Requests must contain the following information:

(*1*) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(*2*) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies.

(*3*) A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with all subpart W reporting requirements.

(C) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that the owner or operator faces unique safety, technical or legal issues rendering them unable to meet the requirements of this subpart for 2011.

(6) *Requests for extension of the use of best available monitoring methods through December 31, 2011 for sources in paragraph (f)(2) of this section.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods described in paragraph (f)(2) of this section beyond June 30, 2011.

(i) *Timing of request.* The extension request must be submitted to EPA no later than April 30, 2011.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific source types and specific equipment, monitoring instrumentation, contract modifications, and/or services for which the request is being made and the locations where each piece of monitoring instrumentation will be installed, monitoring service will be supplied, or contracts will be modified.

(B) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the instrumentation, contract modification, or monitoring service is needed.

(C) A description and applicable correspondence outlining the diligent efforts of the owner or operator in obtaining the needed equipment or service and why they could not be obtained and installed in a period of time enabling completion of applicable requirements of this subpart within the 2011 calendar year.

(D) If the reason for the extension is that the owner or operator cannot collect data from a service provider or relevant organization in order for the owner or operator to meet requirements of this subpart for the 2011 calendar year, the owner or operator must demonstrate a good faith effort that it is not possible to obtain the necessary information, service or hardware which may include providing correspondence from specific service providers or other relevant entities to the owner or operator, whereby the service provider states that it is unable to provide the necessary data or services requested by the owner or operator that would enable the owner or operator to comply with subpart W reporting requirements by June 30, 2011.

(E) A description of the specific actions the owner or operator will take to comply with monitoring requirements in 2012 and beyond.

(iii) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to obtain the data necessary to meet the requirements of this subpart for the sources specified in paragraph (f)(2) of this section by June 30, 2011.

(7) *Requests for extension of the use of best available monitoring methods through December 31, 2011 for sources in paragraph (f)(3) of this section.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods described in paragraph (f)(3) of this section beyond June 30, 2011.

(i) *Timing of request.* The extension request must be submitted to EPA no later than April 30, 2011.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific source types for which data collection could not be implemented.

(B) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the data collection could not be implemented.

(C) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies for which data collection could not be implemented in the 2011 calendar year.

(iii) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to implement the data collection for the sources described in paragraph (f)(3) of this section for the methods required in this subpart by June, 30, 2011.

(8) *Requests for extension of the use of best available monitoring methods beyond 2011 for sources listed in paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section and other sources in this subpart.* EPA does not anticipate a need for approving the use of best available methods beyond December 31, 2011, except in extreme circumstances, which include safety, a requirement being technically infeasible or counter to other local, State, or Federal regulations.

(i) *Timing of request.* The request to use best available monitoring methods for paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section and sources not listed in paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section must be submitted to EPA no later than September 30, 2011.

(ii) *Content of request.* Requests must contain the following information:

(iii) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(iv) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies.

(v) A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with all of this subpart W reporting requirements.

(C) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that the owner or operator faces unique safety, technical or legal issues rendering them unable to meet the requirements of this subpart.

§ 98.235 Procedures for estimating missing data.

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data which are continuously monitored or measured, (for example flow meters), or for missing temperature or pressure data that are required under § 98.236, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section in metric tons CO_2e per year at standard conditions. For each segment, report emissions from each source type § 98.232(a) in the aggregate, unless specified otherwise. For example, an onshore natural gas production operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Onshore petroleum and natural gas production.

(2) Offshore petroleum and natural gas production.

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) LNG storage.

(7) LNG import and export.

(8) Natural gas distribution. Report each source in the aggregate for pipelines and for Metering and Regulating (M&R) stations.

(b) Offshore petroleum and natural gas production is not required to report activity data and emissions for each aggregated source under § 98.236(c). Reporting requirements for offshore petroleum and natural gas production is set forth by BOEMRE in compliance with 30 CFR 250.302 through 304.

(c) For each aggregated source, unless otherwise specified, report activity data and emissions (in metric tons CO_2e per year at standard conditions) for each aggregated source type as follows:

(1) For natural gas pneumatic devices (refer to Equation W–1 of § 98.233), report the following:

(i) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable.

(ii) Actual count and estimated count separately of natural gas pneumatic low bleed devices as applicable.

(iii) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable.

(iv) Report emissions collectively.

(2) For natural gas driven pneumatic pumps (refer to Equation W–2 of § 98.233), report the following,

(i) Count of natural gas driven pneumatic pumps.

(ii) Report emissions collectively.

(3) For each acid gas removal unit (refer to Equation W–3 and Equation W–4 of § 98.233), report the following:

(i) Total throughput off the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.

(ii) For Calculation Methodology 1 and Calculation Methodology 2 of § 98.233(d), fraction of CO_2 content in the vent from the acid gas removal unit (refer to § 98.233(d)(6)).

(iii) For Calculation Methodology 3 of § 98.233(d), volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to § 98.233(d)(7) and (d)(8)).

(iv) Report emissions from the AGR unit recovered and transferred outside the facility.

(v) Report emissions individually.

(4) For dehydrators, report the following:

(i) For each Glycol dehydrator with a throughput greater than or equal to 0.4 MMscfd (refer to § 98.233(e)(1)), report the following:

(A) Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.

(B) Glycol dehydrator absorbent circulation pump type.

(C) Whether stripper gas is used in glycol dehydrator.

(D) Whether a flash tank separator is used in glycol dehydrator.

(E) Type of absorbent.

(F) Total time the glycol dehydrator is operating in hours.

(G) Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.

(H) Concentration of CH_4 and CO_2 in natural gas.

(I) What vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(J) Report vent and flared emissions individually.

(ii) For all glycol dehydrators with a throughput less than 0.4 MMscfd (refer to § 98.233, Equation W–5 of § 98.233), report the following:

(A) Count of glycol dehydrators.

(B) Whether any vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(C) Report vent emissions collectively.

(iii) For absorbent desiccant dehydrators (refer to Equation W–6 of § 98.233), report the following:

(A) Count of desiccant dehydrators.

(B) Report emissions collectively.

(5) For well venting for liquids unloading (refer to Equations W–7, W–8 and W–9 of § 98.233), report the following by field:

(i) Count of wells vented to the atmosphere for liquids unloading.

(ii) Count of plunger lifts.

(iii) Cumulative number of unloadings vented to the atmosphere.

(iv) Average flow rate of the measured well venting in cubic feet per hour (refer to § 98.233(f)(1)(i)(A)).

(v) Average casing diameter in inches.

(vi) Report emissions collectively.

(6) For well completions and workovers, report the following for each field:

(i) For gas well completions and workovers with hydraulic fracturing (refer to Equation W–10 of § 98.233):

(A) Total count of completions in calendar year.

(B) Average flow rate of the measured well completion venting in cubic feet per hour (refer to § 98.233(g)(1)(i) or (g)(1)(ii)).

(C) Total count of workovers in calendar year.

(D) Average flow rate of the measured well workover venting in cubic feet per hour (refer to § 98.233(g)(1)(i) or (g)(1)(ii)).

(E) Total number of days of gas venting to the atmosphere during backflow for completion.

(F) Total number of days of gas venting to the atmosphere during backflow for workovers.

(G) Report number of completions and workovers employing reduced emissions completions and engineering estimate based on best available data of the amount of gas recovered to sales.

(H) Report vent emissions collectively. Report flared emissions collectively.

(ii) For gas well completions and workovers without hydraulic fracturing (refer to Equation W–13 of § 98.233):

(A) Total count of completions in calendar year.

(B) Total count of workovers in calendar year.

(C) Total number of days of gas venting to the atmosphere during backflow for completion.

(D) Report vent emissions collectively. Report flared emissions collectively.

(7) For each blowdown vent stack (refer to Equation W–14 of § 98.233), report the following:

(i) Total number of blowdowns per equipment type in calendar year.

(ii) Report emissions collectively per equipment type.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of § 98.233(j), report the following by field:

(A) Number of wellhead separators sending oil to atmospheric tanks.

(B) Estimated average separator temperature, in degrees Fahrenheit, and estimated average pressure, in psig.

(C) Estimated average sales oil stabilized API gravity, in degrees.

(D) Count of hydrocarbon tanks at well pads.

(E) Best estimate of count of stock tanks not at well pads receiving your oil.

(F) Total volume of oil from all wellhead separators sent to tank(s) in barrels per year.

(G) Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads.

(H) Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving your oil.

(I) Range of concentrations of flash gas, CH_4 and CO_2.

(J) Report emissions individually for Calculation Methodology 1 and 2 of § 98.233(j).

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of § 98.233(j), report the following by field:

(A) Total volume of sales oil from all wells in barrels per year.

(B) Total number of wells sending oil directly to tanks.

(C) Total number of wells sending oil to separators off the well pads.

(D) Sales oil API gravity range for (B) and (C) of this section, in degrees.

(E) Count of hydrocarbon tanks on wellpads.

(F) Count of hydrocarbon tanks, both on and off well pads assumed to have emissions control measures: either vapor recovery system or flaring of tank vapors.

(G) Report emissions collectively for Calculation Methodology 3 and 4 of § 98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of § 98.233(j) Equation W–15 of § 98.233), report the following:

(A) Number of wellhead separators.

(B) Number of wells without wellhead separators.

(C) Total volume of oil production in barrels per year.

(D) Best estimate of fraction of production sent to tanks with assumed control measures: either vapor recovery system or flaring of tank vapors.

(E) Count of hydrocarbon tanks on well pads.

(F) Report CO_2 and CH_4 emissions collectively.

(iv) If wellhead separator dump valve is functioning improperly during the calendar year (refer to Equation W–16 of § 98.233), report the following:

(A) Count of wellhead separators that dump valve factor is applied.

(9) For transmission tank emissions identified using optical gas imaging instrument per § 98.234(a) (refer to § 98.233(k)), or acoustic leak detection of scrubber dump valves report the following for each tank:

(i) Report emissions individually.

(ii) [Reserved]

(10) For well testing (refer to Equation W–17 of § 98.233), report the following for each basin:

(i) Number of wells tested per basin in calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Average number of days the well is tested in a basin.

(iv) Report emissions of the venting gas collectively.

(11) For associated natural gas venting (refer to Equation W–18 of § 98.233), report the following for each basin:

(i) Number of wells venting or flaring associated natural gas in a calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Report emissions of the flaring gas collectively.

(12) For flare stacks (refer to Equation W–19, W–20, and W–21 of § 98.233), report the following for each flare:

(i) Whether flare has a continuous flow monitor.

(ii) Volume of gas sent to flare in cubic feet per year.

(iii) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(iv) Whether flare has a continuous gas analyzer.

(v) Flare combustion efficiency.

(vi) Report uncombusted and combusted CO_2 and CH_4 emissions separately.

(13) For each centrifugal compressor:

(i) For compressors with wet seals in operational mode (refer to Equations W–22 through W–24 of § 98.233), report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.

(B) Fraction of vent gas recovered for fuel or sales or flared.

(C) Annual throughput in million scf, use an engineering calculation based on best available data.

(D) Type of meters used for making measurements.

(E) Reporter emission factor for wet seal oil degassing vents in cubic feet per hour (refer to Equation W–24 of § 98.233).

(F) Total time the compressor is operating in hours.

(G) Report seal oil degassing vent emissions for compressors measured (refer to Equation W–22 of § 98.233) and for compressors not measured (refer to Equation W–23 and Equation W–24 of § 98.233).

(ii) For wet and dry seal centrifugal compressors in operating mode, (refer to Equations W–22 through W–24 of § 98.233), report the following:

(A) Total time in hours the compressor is in operating mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to Equation W–24 of § 98.233).

(C) Report blowdown vent emissions when in operating mode (refer to Equation W–23 and Equation W–24 of § 98.233).

(iii) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations W–22 through W–24 of § 98.233), report the following:

(A) Total time in hours the compressor is in shutdown, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in shutdown, depressurized mode in cubic feet per hour (refer to Equation W–24 of § 98.233).

(C) Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W–23 and Equation W–24 of § 98.233).

(iv) Report total annual compressor emissions from all modes of operation (refer to Equation W–24 of § 98.233).

(v) For centrifugal compressors in onshore petroleum and natural gas production (refer to Equation W–25 of § 98.233), report the following:

(A) Count of compressors.

(B) Report emissions (refer to Equation W–25 of § 98.233) collectively.

(14) For reciprocating compressors:

(i) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

(A) Annual throughput in million scf, use an engineering calculation based on best available data.

(B) Total time in hours the reciprocating compressor is in operating mode.

(C) Report rod packing emissions for compressors measured (refer to Equation W–26 of § 98.233) and for compressors not measured (refer to Equation W–27 and Equation W–28 of § 98.233).

(ii) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode (refer to Equations W–26 through W–28 of § 98.233), report the following:

(A) Total time in hours the compressor is in standby, pressurized mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to § 98.233, Equation W–28).

(C) Report blowdown vent emissions when in operating and standby pressurized modes (refer to Equation W–27 and Equation W–28 of § 98.233).

(iii) For reciprocating compressors in not operating, depressurized mode (refer to Equations W–26 through W–28 of § 98.233), report the following:

(A) Total time the compressor is in not operating, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W–28 of § 98.233).

(C) Report the isolation valve leakage emissions in not operating, depressurized mode.

(iv) Report total annual compressor emissions from all modes of operation (refer to Equation W–27 and Equation W–28 of § 98.233).

(v) For reciprocating compressors in onshore petroleum and natural gas production (refer to Equation W–29 of § 98.233), report the following:

(A) Count of compressors.

(B) Report emissions collectively.

(15) For each equipment leak sources that uses emission factors for estimating emissions (refer to § 98.233(q) and (r).

(i) For equipment leaks found in each leak survey (refer to § 98.233(q)), report the following:

(A) Total count of leaks found in each complete survey listed by date of survey and each type of leak source for which there is a leaker emission factor in Tables W–2, W–3, W–4, W–5, W–6, and W–7 of this subpart.

(B) Concentration of CH_4 and CO_2 as described in Equation W–30 of § 98.233.

(C) Report CH_4 and CO_2 emissions (refer to Equation W–30 of § 98.233) collectively by equipment type.

(ii) For equipment leaks calculated using population counts and factors (refer to § 98.233(r)), report the following:

(A) For source categories § 98.230(a)(3), (a)(4), (a)(5), (a)(6), and (a)(7), total count for each type of leak source in Tables W–2, W–3, W–4, W–5, and W–6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to § 98.230 paragraph (a)(2)), total count for each type of major equipment in Table W–1B and Table W–1C of this subpart, by field.

(C) Report CH_4 and CO_2 emissions (refer to Equation W–31 of § 98.233) collectively by equipment type.

(16) For local distribution companies, report the following:

(i) Number of custody transfer gate stations.

(ii) Number of non-custody transfer gate stations.

(iii) Custody transfer gate station meter run leak factor (refer to Equation W–32 of § 98.233).

(iv) Number of below grade M&R stations with inlet pressure greater than 300 psig.

(v) Number of below grade M&R stations with inlet pressure between 100 and 300 psig.

(vi) Number of below grate M&R stations with inlet pressure less than 100 psig.

(vii) Number of miles of unprotected steel distribution mains.

(viii) Number of miles of protected steel distribution mains.

(ix) Number of miles of plastic distribution mains.

(x) Number of miles of cast iron distribution mains.

(xi) Number of unprotected steel distribution services.

(xii) Number of protected steel distribution services.

(xiii) Number of plastic distribution services.

(xiv) Number of copper distribution services.

(xv) Total emissions from each natural gas distribution facility.

(17) For each EOR injection pump blowdown (refer to Equation W–37 of § 98.233), report the following:

(i) Pump capacity, in barrels per day.

(ii) Volume of critical phase gas between isolation valves.

(iii) Number of blowdowns per year.

(iv) Critical phase EOR injection gas density.

(v) Report emissions collectively.

(18) For EOR hydrocarbon liquids dissolved CO_2 for each field (refer to Equation W–38 of § 98.233), report the following:

(i) Volume of crude oil produced in barrels per year.

(ii) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

(iii) Report emissions individually.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(i) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 mmBtu/hr, by type of unit.

(ii) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iii) Cumulative emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iv) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by fuel type.

(v) Cumulative number of all internal combustion units, by type of unit.

(vi) Cumulative emissions from internal combustion units, by type of unit.

(vii) Cumulative volume of fuel combusted in internal combustion units, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

§ 98.237 Records that must be retained.

Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by § 98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

§ 98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.,* an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see § 98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7).

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of this subpart and for subpart A means the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see § 98.7).

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in § 98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and *Residue Gas Compression* mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore petroleum and natural gas production	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service:[1]	
Valve	0.027
Connector	0.004
Open-ended Line	0.062
Pressure Relief Valve	0.041
Low Continuous Bleed Pneumatic Device Vents[2]	1.80
High Continuous Bleed Pneumatic Device Vents[2]	48.1
Intermittent Bleed Pneumatic Device Vents[2]	17.4
Pneumatic Pumps[3]	13.3
Population Emission Factors—All Components, Light Crude Service:[4]	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other[5]	0.23
Population Emission Factors—All Components, Heavy Crude Service:[6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other[5]	0.002
Western U.S.	
Population Emission Factors—All Components, Gas Service:[1]	
Valve	0.123
Connector	0.017
Open-ended Line	0.032
Pressure Relief Valve	0.196
Low Continuous Bleed Pneumatic Device Vents[2]	1.80
High Continuous Bleed Pneumatic Device Vents[2]	48.1
Intermittent Bleed Pneumatic Device Vents[2]	17.4
Pneumatic Pumps[3]	13.3
Population Emission Factors—All Components, Light Crude Service:[4]	
Valve	0.04
Flange	0.002
Connector (other)	0.005
Open-ended Line	0.04
Pump	0.01
Other[5]	0.23

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION—Continued

Onshore petroleum and natural gas production	Emission factor (scf/hour/component)
Population Emission Factors—All Components, Heavy Crude Service:[6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other[5]	0.002

[1] For multi-phase flow that includes gas, use the gas service emissions factors.

[2] Emission Factor is in units of "scf/hour/device."

[3] Emission Factor is in units of "scf/hour/pump."

[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude.".

[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

TABLE W–1C TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR CRUDE OIL PRODUCTION EQUIPMENT

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

TABLE W–1D OF SUBPART W OF PART 98—DESIGNATION OF EASTERN AND WESTERN U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana

TABLE W–1D OF SUBPART W OF PART 98—DESIGNATION OF EASTERN AND WESTERN U.S.—Continued

Eastern U.S.	Western U.S.
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah
	Washington
	Wyoming

TABLE W–2 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing	Emission Factor (scf/hour/component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve	6.52
Connector	5.80
Open-Ended Line	11.44
Pressure Relief Valve	2.04
Meter	2.98

[1] Valves include control valves, block valves and regulator valves.

TABLE W–3 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission Factor (scf/hour/component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve[1]	6.52
Connector	5.80
Open-Ended Line	11.44
Pressure Relief Valve	2.04

TABLE W–3 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION—Continued

Onshore natural gas transmission compression	Emission Factor (scf/hour/component)
Meter	2.98
Population Emission Factors—Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.41
High Continuous Bleed Pneumatic Device Vents[2]	18.8
Intermittent Bleed Pneumatic Device Vents[2]	18.8

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device."

TABLE W–4 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission Factor (scf/hour/component)
Leaker Emission Factors—Storage Station, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Leaker Emission Factors—Storage Station, Gas Service	
Open-ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.41
High Continuous Bleed Pneumatic Device Vents[2]	18.8
Intermittent Bleed Pneumatic Device Vents[2]	18.8

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device"

TABLE W–5 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors—LNG Storage Components, LNG Service	
Valve	1.21
Pump Seal	4.06
Connector	0.35
Other[1]	1.80
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.23

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor."

TABLE W–6 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission Factor (scf/hour/component)
Leaker Emission Factors—LNG Terminals Components, LNG Service	
Valve	1.21
Pump Seal	4.06
Connector	0.35
Other[1]	1.80
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.23

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor."

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors—Above Grade M&R at City Gate Stations[1] Components, Gas Service	
Connector	1.72
Block Valve	0.566
Control Valve	9.48
Pressure Relief Valve	0.274
Orifice Meter	0.215

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION—Continued

Natural gas distribution	Emission Factor (scf/hour/component)
Regulator	0.784
Open-ended Line	26.533
Population Emission Factors—Below Grade M&R[2] Components, Gas Service[3]	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.32
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure < 100 psig	0.10
Population Emission Factors—Distribution Mains, Gas Service[4]	
Unprotected Steel	12.77
Protected Steel	0.36
Plastic	1.15
Cast Iron	27.67
Population Emission Factors—Distribution Services, Gas Service[5]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] City gate stations at custody transfer and excluding customer meters.
[2] Excluding customer meters.
[3] Emission Factor is in units of “scf/hour/station”.
[4] Emission Factor is in units of “scf/hour/mile”.
[5] Emission Factor is in units of “scf/hour/number of services”.

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