ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2009–0923; FRL–9131–1]

RIN 2060–AP99

Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing a supplemental rule to require reporting of greenhouse gas (GHG) emissions from petroleum and natural gas systems. Specifically, the proposed supplemental rulemaking would require emissions reporting from the following industry segments: Onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission compressor stations, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export terminals, and distribution. The proposed supplemental rulemaking does not require control of GHGs, rather it requires only that sources above certain threshold levels monitor and report emissions.

DATES: Comments must be received on or before June 11, 2010. There will be one public hearing. The hearing will be on April 19, 2010 in Arlington, VA and will begin at 8 a.m. local time and end at 5 p.m. local time.

ADDRESSES: You may submit your comments, identified by docket EPA–HQ–OAR–2009–0923 and/or RIN number 2060–AP99 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *E-mail: GHG_Reporting_Rule_Oil_and_Natural_Gas@epa.gov.* Include EPA–HQ–OAR–2009–0923 and/or RIN number 2060–AP99 in the subject line of the message.
- *Fax:* (202) 566–1741.
- *Phone:* (202) 566–1744.
- *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Attention Docket EPA–HQ–OAR–2009–0923, Mail Code 2822T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center Public Reading Room, Room 3334, EPA West Building, Attention Docket EPA–HQ–OAR–2009–0923, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2009–0923. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Docket, EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER GENERAL 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: *GHGMRR@epa.gov.* For technical information contact the Greenhouse Gas Reporting Rule Hotline at telephone number: (877) 444–1188; or e-mail: *GHGMRR@epa.gov.* To obtain information about the public hearings or to register to speak at the hearings, please go to *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.* Alternatively, contact Carole Cook at 202–343–9263.

SUPPLEMENTARY INFORMATION: EPA first proposed Mandatory GHG Reporting requirements for petroleum and natural gas systems (under 40 CFR, part 98, subpart W) in April 2009. EPA received a substantial number of comments on this initial proposal for petroleum and natural gas systems. For this reason, EPA decided not to finalize the rule for petroleum and natural gas systems, and instead to propose a supplemental rule.

EPA reviewed and considered comments submitted on the previous proposal in drafting this proposed supplemental rulemaking. However, as this is a new proposal, EPA is not here responding to comments on the earlier version of this rule. Any comments must be submitted as provided herein, to be considered. A more detailed background concerning the subpart W rulemaking and proposed changes can be found in section II–A.

Additional Information on Submitting Comments: To expedite review of your comments by Agency staff, you are encouraged to send a separate copy of your comments, in addition to the copy you submit to the official docket, to Carole Cook, U.S. EPA, Office of Atmospheric Programs, Climate Change Division, Mail Code 6207–J, 1200 Pennsylvania Ave., NW., Washington, DC 20460, telephone (202) 343–9263, e-mail: *GHG_Reporting_Rule_Oil_and_Natural_Gas@epa.gov.*

Although as indicated above, EPA previously proposed a version of this rule, that proposal never became final. This is a newly proposed rule and comments which were submitted on the earlier version of the rule are not being considered in the context of this rule. Any parties interested in commenting must do so at this time.

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 is a proposed regulation. If finalized, these regulations would affect owners or operators of petroleum and natural gas systems. Regulated categories and entities 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. Table 1 of this preamble lists the types of facilities that EPA is now aware could be potentially affected by the reporting requirements. Other types of facilities 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 proposed 40 CFR part 98, subpart A or the relevant criteria in the sections related to petroleum and natural gas systems. 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 proposed supplemental rule have GHG emissions from multiple source categories listed in Table 1 of this preamble. Table 2 of this preamble has been developed as a guide to help potential reporters in the petroleum and natural gas industry subject to the proposed rule identify the source categories (by subpart) that they may need to (1) consider in their facility applicability determination, and/or (2) include in their reporting. 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.
	40 CFR part 98, subpart Y.
	40 CFR part 98, subpart MM.
	40 CFR part 98, subpart NN.
	40 CFR part 98, subpart PP.
	40 CFR part 98, subpart RR (proposed).

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

ASTM American Society for Testing and Materials
CAA Clean Air Act
CBI confidential business information
cf cubic feet
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
EO Executive Order
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
GHG greenhouse gas
GWP global warming potential
ICR information collection request
IPCC Intergovernmental Panel on Climate Change
kg kilograms
LDCs local natural gas distribution companies
LNG liquefied natural gas
LPG liquefied petroleum gas
MRR mandatory GHG reporting rule
$MMTCO_2e$ million metric tons carbon dioxide equivalent
N_2O nitrous oxide
NAICS North American Industry Classification System
NGLs natural gas liquids
OMB Office of Management and Budget
QA quality assurance
QA/QC quality assurance/quality control
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
SSM startup, shutdown, and malfunction
TCR The Climate Registry
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
VOC volatile organic compound(s)
WCI Western Climate Initiative

Table of Contents

I. Background

A. Organization of This Preamble

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

The first section of this preamble contains the basic background information about the origin of this proposed supplemental rulemaking, including a discussion of the initial proposed rule for petroleum and natural gas systems. This section also discusses EPA's use of our legal authority under the Clean Air Act to collect the proposed data, and the benefits of collecting the data. The relationship between the mandatory GHG reporting program and other mandatory and voluntary reporting programs at the national, regional and State level also is discussed.

The second section of this preamble summarizes the general provisions of this proposed supplemental rulemaking for petroleum and natural gas systems. It also highlights the major changes between the initial proposed rule and the supplemental rule that we are proposing today, including changes in the scope of the proposed rule and the monitoring methods proposed. This section then provides a brief summary of, and rationale for, selection of key design elements. Specifically, this section describes EPA's rationale for (i) the definition of the source category (ii) selection of reporting thresholds (iii) selection of monitoring methods, (iv) missing data procedures (v) proposed data reporting requirements, and (vi) recordkeeping requirements. Thus, for example, there is a specific discussion regarding appropriate thresholds, monitoring methodologies and reporting and recordkeeping requirements for each segment of the petroleum and natural gas industry proposed for inclusion in the rule: onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission compressor stations, natural gas underground storage, LNG storage, LNG import and export terminals, and distribution. EPA describes the proposed options for each design element, as well as the other options considered. Throughout this discussion, EPA highlights specific issues on which we solicit comment. Please refer to the specific source category of interest for more details.

The third section provides the summary of the cost impacts, economic impacts, and benefits of this proposed rule from the Economic Analysis. Finally, the last section discusses the various statutory and executive order requirements applicable to this proposed rulemaking.

B. Background on the Proposed Rule

The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) was signed by EPA Administrator Lisa Jackson on September 22, 2009 and published in the **Federal Register** on October 30, 2009 (74 FR 209 (October 30, 2009) pp. 56260–56519). The Final MRR which is effective on December 29, 2009 included reporting of GHGs from facilities and suppliers that EPA determined met the criteria in the 2008 Consolidated Appropriations Act.[1] These source categories capture approximately 85 percent of U.S. GHG emissions through reporting by direct emitters as well as suppliers of fossil fuels and industrial gases. There are, however, many additional types of data and reporting that the Agency deems important and necessary to address an issue as large and complex as climate change (*e.g.* indirect emissions from electricity use). In that sense, one could view the Final MRR (40 CFR part 98) as focused on certain sources of emissions and upstream suppliers. For information on existing programs at the Federal, Regional and State levels that also collect valuable information to inform and implement policies necessary to address climate change, relationship of the Final MRR to EPA and U.S. government climate change efforts and to other State and Regional Programs, see the Preamble to the Final MRR.

In the April 2009 proposed mandatory GHG reporting rule the petroleum and natural gas systems subcategory was included as Subpart W. EPA received a number of lengthy, detailed comments regarding this subpart W proposal. Some comments were focused on the significant cost burden that the April 2009 proposed rule would impose on petroleum and natural gas systems, whereas others focused on whether certain sources, such as onshore production and distribution, that were not included in the initial proposal, should be included. EPA recognized the concerns raised by stakeholders, and decided not to finalize subpart W with the Final MRR, but instead to propose a new supplemental rule for petroleum and natural gas systems. This proposed supplemental rule incorporates a number of changes including, but not limited to, different methodologies that provide improved emissions coverage at a lower cost burden to facilities than would have been covered under the initial proposed rule; the inclusion of onshore production and distribution facilities; and separate definitions for "vented" and "fugitive" emissions. As noted earlier, stakeholders should submit comments in the context of this new proposed supplemental rule.

This proposed supplemental rule 40 CFR part 98, subpart W requires annual reporting of fugitive and vented carbon dioxide (CO_2) and methane (CH_4) emissions from petroleum and natural gas systems facilities, as well as combustion-related CO_2, CH_4, and nitrous oxide (N_2O) emissions from flares at those facilities, following the methods outlined in the proposal. This proposed rule would also establish appropriate thresholds and frequency for reporting, as well as provisions to ensure the accuracy of emissions through monitoring, reporting and recordkeeping requirements.

This proposed 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. Reporting would be at the facility level.

C. Legal Authority

EPA is proposing this rule under its existing CAA authority, specifically authorities provided in section 114 of the CAA. As discussed further below and in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Legal Issues" (EPA–HQ–OAR–2008–0508–2264), EPA is not citing the FY 2008 Consolidated Appropriations Act as the statutory basis for this action. While that law required that EPA spend no less than $3.5 million on a rule requiring the mandatory reporting of GHG emissions, it is the CAA, not the Appropriations Act, that EPA is citing as the authority to gather the information proposed by this rule.

As stated in the Final MRR, CAA section 114 provides EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to EPA's carrying out a wide variety of CAA provisions. As discussed in the initial proposed rule (74 FR 16448, April 10, 2009), section 114(a)(1) of the CAA authorizes the Administrator to require emissions sources, persons

[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128.

subject to the CAA, manufacturers of control equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA.

EPA notes that comments were submitted on the initial rule proposal questioning EPA's authority under the Clean Air Act to collect emissions information from certain offshore petroleum and natural gas platforms. Some commenters argued that EPA does not have the authority to collect emissions information from offshore platforms located in areas of the Western Gulf because they are under the jurisdiction of the Department of the Interior. They cited, among other things, the Outer Continental Shelf Act, 43 U.S.C. 1334. Without opining on the accuracy of the commenter's summary of OCSLA or other law, we note that even the commenter describes these authorities as relating to the regulation of air emissions. Today's proposal 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 these and other offshore platforms will inform our analyses, including options applicable to emissions of any offshore platforms that EPA is authorized to regulate under the CAA.

EPA is proposing to amend 40 CFR 98.2(a) so that the final MRR applies to facilities located in the United States and on or under the Outer Continental Shelf. These revisions are necessary to ensure that any petroleum or natural gas platforms located on our under the Outer Continental Shelf of the United States would be required to report under this rule. In addition, EPA is proposing revisions to the definition of United States to clarify that the United States includes the territorial seas. Other facilities located offshore of the United States covered by the mandatory reporting program at 40 CFR part 98 would also be affected by this change in the definition of United States. Revising the definition of United States will also ensure that facilities located offshore of the United States that are injecting CO_2 into sub-seabed for long-term containment will also be required to report data regarding greenhouse gases. EPA is proposing a separate rule on geologic sequestration and any comments specific to that issue should be directed to the Agency on that rulemaking not this one. Finally, in addition to the change to the definition of United States, EPA is adding a definition of "Outer Continental Shelf." This definition is drawn from the definition in the U.S. Code. Together, these changes make clear that the Mandatory GHG Reporting Rule applies to facilities on land, in the territorial seas, or on or under the Outer Continental Shelf, of the United States, and that otherwise meet the applicability criteria of the rule.

For further information about EPA's legal authority, see the proposed and final MRR.

D. Relationship to Other Federal, State and Regional Programs

In developing the initial proposal for mandatory reporting from petroleum and natural gas systems that was released in April 2009, as well as this supplemental proposed rulemaking, EPA reviewed monitoring methods included in international guidance (*e.g.,* Intergovernmental Panel on Climate Change), as well as Federal voluntary programs (*e.g.,* EPA Natural Gas STAR Program and the U.S. Department of Energy Voluntary Reporting of Greenhouse Gases Program (1605(b)), corporate protocols (*e.g.,* World Resources Institute and World Business Council for Sustainable Development GHG Protocol) and industry guidance (*e.g.,* methodological guidance from the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association).

EPA also reviewed State reporting programs (*e.g.,* California and New Mexico) and Regional partnerships (*e.g.,* The Climate Registry, the Western Regional Air Partnership). These are important programs that not only led the way in reporting of GHG emissions before the Federal government acted but also assist in quantifying the GHG reductions achieved by various policies. Many of these programs collect different or additional data as compared to this proposed rule. For example, State programs may establish lower thresholds for reporting, request information on areas not addressed in EPA's reporting rule, or include different data elements to support other programs (*e.g.,* offsets). For further discussion on the relationship of this proposed rule to other programs, refer to the preamble to the Final MRR.

II. Rationale for the Reporting, Recordkeeping and Verification Requirements

A. Overview of Proposal

The U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. This proposed rule would apply to the calculation and reporting of vented, fugitive, and flare combustion emissions from selected equipment at the following facilities that emit equal to or greater than 25,000 metric tons of CO_2 equivalent per year from source categories covered by the mandatory GHG reporting rule: offshore petroleum and natural gas production facilities, onshore petroleum and natural gas production facilities (including enhanced oil recovery (EOR)), onshore natural gas processing facilities, onshore natural gas transmission compression facilities, onshore natural gas storage facilities, LNG storage facilities, LNG import and export facilities and natural gas distribution facilities owned or operated by local distribution companies (LDCs). This proposal does not address the production of gas from landfills or manure management systems. Methods and reporting procedures for stationary combustion emissions other than flares at petroleum and natural gas industry facilities are covered under Subpart C of the Final MRR.

This proposed supplemental rule incorporates a number of different methodologies to provide improved emissions coverage at a lower cost burden to affected facilities, as compared to the initial proposed rule. In this supplemental proposal, EPA is requiring the use of direct measurement of emissions for only the most significant emissions sources where other options are not available, and proposing the use of engineering estimates, emissions modeling software, and leak detection and publicly available emission factors for most other vented and fugitive sources. For smaller fugitive and inaccessible to plain view sources, component count and population emissions factors are proposed. In the case of offshore platforms, EPA is recommending that emissions sources identified under the Minerals Management Services (MMS) GOADS (Gulfwide Offshore Activities Data System) be used for reporting, and the GOADS process be extended to platforms in other Federal regions (*i.e.,* California and Alaska) and in State waters. The alternative methodologies proposed in this rule will provide similar or better estimation of vented and fugitive CH_4 and CO_2 emissions in the petroleum and gas industry, while significantly reducing industry burden.

Under this supplemental proposal, facilities not already reporting but required to report under subpart W would begin data collection in 2011 following the methods outlined in the proposed rule, and submit data to EPA by March 31, 2012.

EPA would require reporting of calendar year 2011 emissions in 2012 because the data are crucial to the timely development of future GHG policy and regulatory programs. In the Appropriation Act, Congress requested EPA to develop this reporting program on an expedited schedule, and Congressional inquiries along with public comments reinforce that data collection for calendar year 2011 is a priority. Delaying data collection until calendar year 2012 would mean the data would not be received until 2013, which would likely be too late for many ongoing GHG policy and program development needs.

EPA considered, but decided not to propose, the use of best available monitoring methods for part (*e.g.,* the first three months) or all of the first year of data collection. EPA concluded that the time period that would be allowed under this schedule is sufficient to allow facilities to implement the monitoring methods that would be required by the proposed rule. In general, the proposed monitors are widely available and are not time consuming to install. Further, some of the monitoring methods (*e.g.,* use of emission factors) may not require the installation of any monitoring equipment. Finally, the emissions assessment may be done at any time during the year, and measurements do not necessarily need to be undertaken during the first quarter.

EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenters recommend that EPA allow the use of best available monitoring methods for a designated time period (*e.g.,* three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used.

Amendments to the General Provisions. In a separate rulemaking package that was recently published (March 16, 2010), EPA issued minor harmonizing changes to the general provisions for the GHG reporting rule (40 CFR part 98, subpart A) to accommodate the addition of source categories not included in the 2009 final rule (*e.g.,* subparts proposed in April 2009 but not finalized in 2009, any new subparts that may be proposed in the future). The changes update 98.2(a) on rule applicability and 98.3 regarding the reporting schedule to accommodate any additional subparts and the schedule for their reporting obligations (*e.g.,* source categories finalized in 2010 would not begin data collection until 2011 and reporting in 2012).

In particular, we restructured 40 CFR 98.2(a) to move the lists of source categories from the text into tables. A table format improves clarity and facilitates the addition of source categories that were not included in calendar year 2010 reporting and would begin reporting in future years. A table, versus list, approach allows other sections of the rule to be updated automatically when the table is updated; a list approach requires separate updates to the various list references each time the list is changed. In addition to reformatting the 98.2(a)(1)–(2) lists into tables, other sections of subpart A were reworded to refer to the source category tables because the tables make it clear which source categories are to be considered for determining the applicability threshold and reporting requirements for calendar years 2010, 2011, and future years.

Because facilities with petroleum and natural gas systems (as defined in proposed 40 CFR part 98, subpart W) would be subject to the rule if facility emissions exceed 25,000 metric tons CO_2e per year, in today's rule we are proposing to add this source category to those threshold categories referenced from 40 CFR 98.2(a)(2) whether the reference is to a list or a table.[2]

In today's proposal, we also propose to amend 40 CFR 98.6 to add definitions for several terms used in proposed 40 CFR part 98, subpart W and to clarify the meaning of certain terms for purposes of subpart W. We also propose to amend 40 CFR 98.7 (incorporation by reference) to include standard methods used in proposed subpart W. In particular, we propose to incorporate by reference the AAPG–CSD Geologic Code Provinces Code Map available from The American Association of Petroleum Geologists Bulletin, Volume 75, No. 10 (October 1991) pages 1644–1651. It would be used to define the geographic boundaries for reporting of onshore oil and gas production systems. We also proposed to incorporate by reference models, including Glycalc and E&P Tanks that would be used to calculate emissions and were not developed by the Federal government.

B. Summary of the Major Changes Since Initial Proposal

Mandatory GHG reporting requirements were proposed for Petroleum and Natural Gas Systems under Subpart W in April 2009 along with a number of other sectors of the economy. As noted in the Preamble to the Final MRR, EPA received a number of lengthy, detailed comments regarding Petroleum and Natural Gas Systems. In total, EPA received comments from over 80 organizations and over 1,200 pages of formal comments on the Petroleum and Gas Systems Initial Proposed Rule. Some comments proposed simplified alternatives to the proposed reporting requirements based on the potential that the proposed requirements would entail significant burden and cost. Other comments addressed whether to include onshore production and the distribution segment, which were excluded from the initial proposal as EPA sought comments on approaches for the level of reporting of fugitive and vented GHG emissions from these segments (*e.g.,* facility or corporate).

EPA has reviewed the comments and issues and suggestions raised by stakeholders within and outside the petroleum and natural gas industry related to emissions coverage and the level of cost burden in this sector. In response, EPA is proposing a new supplemental rule for Petroleum and Natural Gas Systems. This proposed supplemental rule now incorporates all segments of the petroleum and gas industry, adding onshore production and distribution.

Total fugitive, vented and combustion emissions estimated to be covered in this supplemental proposed rulemaking amount to 351 $MMTCO_2e$; 272 $MMTCO_2e$ from fugitive and vented emissions and 79 $MMTCO_2e$ from combustion emissions.[3] Fugitive and

[2] Since we are proposing to change the list of covered subcategories to tables, we are not providing regulatory text in this proposal because the preamble is clear.

[3] Some petroleum and natural gas facilities will already be required to report emissions from stationary combustion under the MRR that was

vented emissions estimates included in the supplemental proposed rulemaking are significantly higher than the 131 $MMTCO_2e$ reported in the 2008 U.S. Inventory of Greenhouse Gases, due to the inclusion of items believed to be under-reported in the inventory (discussed further below).

Table W–1 summarizes the estimated fugitive, vented and combustion emissions for the segments included in the initial proposal and the added segments of onshore production and distribution. Additional details can be found in the Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions under Subpart W Supplemental Rule (EPA–HQ–OAR–2009–0923).

TABLE W–1—FUGITIVE/VENTED AND COMBUSTION EMISSIONS FROM PETROLEUM AND NATURAL GAS SYSTEMS, $MMTCO_2e$

Segment	Fugitive and vented emissions: Initial proposed rule	Fugitive and vented emissions: Supplemental proposed rulemaking	Combustion emissions: Supplemental proposed rulemaking
Initial Proposed Rule Six Segments	85	94.3	9.8
Onshore Production	NA	154.9	69.3
Natural Gas Distribution	NA	22.7	NA
Total Emissions	85	271.9	[1] 79.1

[1] This estimate reflects only incremental combustion emissions (*i.e.*, only those combustion emissions from facilities above and beyond what will already be required to be reported under the Final MRR). For example, combustion-related emissions ftrom many natural gas processing plants are already required to be reported under subpart C and are therefore not included here. The combustion estimate also includes combustion emissions from flares.

Inclusion of onshore production and distribution results in estimated fugitive and vented emissions that are more than triple the estimated emissions in the initial rule proposal for petroleum and natural gas systems.

In addition to expanding emissions coverage under the proposed supplemental rule, EPA has assessed a number of alternative methodologies that were either recommended by commenters or are known to provide effective quantification of emissions at a significantly lower cost burden. The changes include the use of:

- Limited use of fugitive leak detection.
- Leaker factors to quantify detected fugitive emissions.
- Population factors and component count for fugitive emissions that are widely scattered or inaccessible to plain view.
- Use of existing MMS GOADS methods and calculated emissions for offshore production facilities.
- Modeling software to quantify glycol dehydrator and tank emissions.
- Engineering estimation for well venting from liquids unloading.
- Engineering estimation for well venting from completions and workovers.
- Engineering estimation for well testing and flaring.
- Engineering estimation for flaring emissions.
- Limited sampling to determine gas composition.

Another significant change in the proposed supplemental rule is the use of the term "fugitives". The initial rule proposal from April 2009 included both vented and fugitive emissions sources, and collectively defined both sources as "fugitive". EPA received a large number of comments from industry stakeholders and others indicating that this definition created confusion. Hence EPA is defining vented emissions separately from fugitives in the supplemental proposed rulemaking. For this supplemental rulemaking, emissions from the petroleum and natural gas industry are defined as (1) vented emissions, which include intentional or designed releases of CH_4 and/or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas) from emissions sources including, but not limited to, 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). In addition, this supplemental rule includes (2) fugitive emissions, or unintentional emissions, which are defined to include those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. This supplemental rule also includes (3) flare combustion emissions, which include CH_4, CO_2 and N_2O emissions resulting from combustion of gas in flares. EPA seeks comment on the use of the term "equipment leak" versus "fugitive" and "vented" as defined in the proposed supplemental rule.

C. Definition of the Source Category

EPA discusses here the general approach used in identifying the key segments of the petroleum and natural gas industry that would be required to report under the proposal. This general discussion is followed by a specific discussion for each industry segment.

One factor EPA considered in assessing the applicability of certain petroleum and natural gas industry emissions in the proposed rule is the definition of a facility. In other words, what physically constitutes a facility? This definition is important to determine the reporting entity, to ensure that delineation is clear, and to minimize double counting or omissions of emissions. For some segments of the industry (*e.g.,* onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities. In other segments of the industry (*e.g.,* the pipelines between compressor stations and onshore petroleum and natural gas production) such distinctions are not as

signed in September 2009. This proposed petroleum and natural gas subpart will require additional facilities to report to the MRR that are not currently required to report. These facilities will have to report combustion, fugitive and vented emissions. These incremental combustion emissions are estimated at 79 $MMTCO_2e$.

straightforward. In defining a facility, EPA reviewed current definitions used in the Clean Air Act (CAA), ISO definitions, comments provided under the initial proposed rule, and current regulations relevant to the industry. A complete description of our assessment can be found in Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) (EPA–HQ–OAR–2009–0923).

At the same time, EPA also decided that it was impractical to include each of the over 160 different sources of vented and fugitive CH_4 and CO_2 emissions in the petroleum and natural gas industry. In response to comments received on the initial proposed rule, EPA undertook a systematic review of each emissions source included in the 2008 U.S. GHG Inventory in order to propose reporting of only the most significant emissions sources (*e.g.* emissions that account for the majority of oil and gas fugitive and vented emissions). In determining the most relevant vented and fugitive emissions sources for inclusion in this supplemental proposed rulemaking, EPA considered the following criteria: The coverage of emissions for the source category as a whole; the coverage of emissions per unit of the source category; the feasibility of a viable monitoring method, including direct measurement and engineering estimations; and the number of facilities that would be required to report. Sources that contribute significantly large emissions were considered for inclusion in this supplemental proposed rulemaking, since they increase the coverage of emissions reporting. Typically, at petroleum and gas facilities, 80 percent or more of a facility's emissions come from approximately 10 percent of the emissions sources. EPA used this benchmark to reduce the number of emissions sources required for reporting while keeping the reporting burden to a minimum. Sources in each segment of the petroleum and natural gas industry were sorted into two main categories: (1) The largest sources contributing to approximately 80 percent of the emissions from the segment, and (2) the sources contributing to the remaining 20 percent of the emissions from that particular segment. EPA assigned sources into these two groups by determining the emissions contribution of each emissions source to its relevant segment of the petroleum and gas industry, listing the emissions sources in a descending order, and identifying all the sources at the top that contribute to approximately 80 percent of the emissions. Generally, those sources that fell into approximately the top 80 percent were considered for inclusion. Details of the analysis can be found in Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923).

The following is a brief discussion of the proposed emission sources to be included and excluded based on our analysis. Additional information can be found in Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923. Note that this subpart of the GHG reporting rule addresses only vented, fugitive and flare combustion emissions. As mentioned previously, stationary combustion emissions are included in Subpart C of the Final MRR Preamble.

Onshore Petroleum and Natural Gas Production

The onshore petroleum and natural gas production segment uses wells to extract raw natural gas, condensate, crude oil, and associated gas from underground formations and inject CO_2 for EOR. Extraction includes several types of processes: Reservoir management, primary recovery, secondary recovery such as down-hole pumps, water flood or natural gas/nitrogen/immiscible CO_2 injection, and tertiary recovery such as using critical phase miscible CO_2 injection. The largest sources of CH_4 and CO_2 emissions include, but are not limited to, natural gas driven pneumatic devices and pumps, field crude oil and condensate storage tanks, glycol dehydration units, releases and flaring during well completions, well workovers, and well blowdowns for liquids unloading, releases and flaring of associated gas, and blowdowns of compressors and EOR pumps.

EPA is proposing to include the onshore petroleum and natural gas production segment due to the fact that these operations represent a significant emissions source, representing approximately 66 percent of fugitive, vented and incremental[4] combustion emissions from the petroleum and natural gas segments covered by the proposed rule.

EPA considered a range of possible options for reporting emissions from onshore petroleum and natural gas facilities. Although several options for defining the facility were considered and described below, EPA has determined that only two of the options are feasible: Basin-level reporting and field-level reporting. For this supplemental proposed rulemaking, EPA proposes that emissions from onshore petroleum and natural gas production be reported at the basin level. The reporting entity for onshore petroleum and natural gas production would be the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state, who operates onshore petroleum and natural gas production wells and controls by means of ownership (including leased and rented) and operation (including contracted) stationary and portable (as defined in this Subpart) equipment located on all well pads within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists (AAPG) three-digit Geological Province Code. The equipment referenced above includes all structures associated with wells used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate) including equipment that is leased, rented or contracted. This includes equipment such as compressors, generators or storage facilities, piping (such as flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (such as well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment). This also includes associated storage or measurement equipment and all equipment engaged in gathering produced gas from multiple wells, EOR operations using CO_2, and all petroleum and natural gas production operations located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

Where more than one entity may hold the state well drilling permit, or well operating permit where no drilling permit is issued by the state, the permitted entities for the facility would be required to designate one entity to report all emissions from the jointly controlled facility. Where an operating entity holds more than one permit to operate wells in a basin, then all onshore petroleum and natural gas production well permits in their name in the basin, including all equipment on the well pads, would be considered one onshore petroleum and natural gas

[4] The denominator includes total fugitive and vented emissions, as well as any additional combustion related emissions that will be required to be reported by the petroleum and natural gas industry and that wasn't already covered in the final MRR.

production facility for purposes of reporting.

There are at least two industry recognized definitions available that identify hydrocarbon basins; one from the United State Geological Survey (USGS) and the other from the AAPG. The AAPG geologic definition 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. Basins are mapped to county boundaries only to give a surface manifestation to the underground geologic structures, thus making it easier to relate surface facilities to basin underground geologic boundaries. On the other hand, the USGS definition is based purely on the geology of the hydrocarbon basin without consideration of state and county boundaries. Hence using the USGS definition may make it more difficult to map surface operations to a particular basin. Therefore, EPA is proposing to use the AAPG definition of a basin. EPA seeks comments on the availability of other appropriate standard basin level definitions that could be applied for the purposes of this rule and their merits over the AAPG definition.

EPA is proposing a basin level approach, because the boundaries for reporting are clearly defined and the approach covers approximately 81 percent of emissions from onshore petroleum and natural gas production.

EPA evaluated and is taking comment on one alternative option for reporting from onshore petroleum and natural gas production; field level. Field level reporting would require aggregation of emissions from all covered equipment at onshore petroleum and natural gas production facilities at the field level, as opposed to the basin level as described above. A typical field level definition is available from the Energy Information Administration Oil and Gas Field Code Master. As outlined in the Economic Impact Analysis for this proposed rule, the field level option would result in a significantly lower coverage in emissions, estimated at 55 percent in comparison to the basin level coverage of 81 percent. In essence the two reporting options are not different from a methodological point of view because both definitions rely on geographical boundaries. Therefore, EPA has proposed the use of a basin level definition to increase coverage. EPA seeks comments on our decision to propose the basin level approach, and whether there would be advantages to requiring reporting at the field level instead.

In addition to basin and field level reporting, EPA considered one other alternative approach for defining a facility for onshore petroleum and natural gas production; individual well pads. This well pad approach included all stationary and portable equipment operating in conjunction with that well, including drilling rigs with their ancillary equipment, gas/liquid separators, compressors, gas dehydrators, crude oil heater-treaters, gas powered pneumatic instruments and pumps, electrical generators, steam boilers and crude oil and gas liquids stock tanks. This definition was analyzed with available data including four cases to represent the full range of petroleum and natural gas well pad operations ranging from unconventional well drilling and operation starting in the beginning of the year with higher emitting practices, to production at an associated gas and oil well (no drilling) with minimal equipment and a vapor recovery unit.

EPA analyzed the average emissions associated with each of the four well pad facility cases and determined that average emissions at these operations were low (from about 370 metric tons of CO_2e per year to slightly less than 5,000 metric tons of CO_2e per year). This analysis shows that the threshold would have to be set at less than 400 metric tons CO_2e per year to capture the largest possible amount of onshore production emissions (only 33 percent) which would result in close to 170,000 reporters. Additional information can be found in Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923). If the threshold was set at approximately 5,000 metric tons, EPA estimates that the number of reporters would decrease significantly to approximate 3,300 but the emission coverage would be only 6 percent. Based on the results above, EPA did not consider the well pad definition further in the Economic Impact Analysis.

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 transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure. GHG emissions result from sources housed on the platforms.

In 2006, offshore petroleum and natural gas production CO_2 and CH_4 emissions accounted for 5.1 million metric tons CO_2e. The primary sources of emissions from offshore petroleum and natural gas production are from valves, flanges, open-ended lines, compressor seals, platform vent stacks, and other source types. Flare stacks account for the majority of combustion CO_2 emissions.

Offshore petroleum and natural gas production facilities are proposed for inclusion due to the fact that this segment represents approximately 1.9 percent of fugitive, vented and incremental [5] combustion emissions from the petroleum and natural gas industry, an existing activity data collection system already exists that can readily be used to calculate GHG emissions (*i.e.,* GOADS) and major fugitive and vented emissions sources can be characterized by an existing reasonable methodology which will minimize incremental burden for reporters. This is consistent with comments received on the initial proposed rule.

Onshore Natural Gas Processing

Natural gas processing facilities remove hydrocarbon and water liquids and various other constituents (*e.g.,* hydrogen sulfide, carbon dioxide, helium, nitrogen, and hydrocarbons heavier than methane) from the produced natural gas. The resulting "pipeline quality" natural gas is transported to transmission pipelines. Natural gas processing facilities also include gathering/boosting stations that dehydrate and compress natural gas to be sent to natural gas processing facilities or directly to natural gas transmission or distribution systems. Compressors are used within gathering/boosting stations to adequately pressurize the natural gas so that it can be transported to natural gas processing, transmission, and distribution facilities through gathering pipelines. In addition, compressors at natural gas processing facilities are used to boost natural gas pressure so that it can pass through all of the processes and into the high-pressure transmission pipelines.

Vented and fugitive CH_4 emissions from reciprocating and centrifugal compressors, including centrifugal compressor wet and dry seals, wet seal oil degassing vents, reciprocating compressor rod packing vents, and all

[5] The denominator includes total fugitive and vented emissions, as well as any additional combustion related emissions that will be required to be reported by the petroleum and natural gas industry and that wasn't already covered in the final MRR.

other compressor emissions, are the primary CH_4 emission sources from this segment. The majority of vented CO_2 emissions come from acid gas removal vent stacks, which are designed to remove CO_2 and hydrogen sulfide, when present, from natural gas. While these are the major emissions sources in natural gas processing facilities, other potential sources such as dehydrator vent stacks, piping connectors, open-ended vent and drain lines and gathering pipelines associated with the processing plant would also need to be reported under the proposed supplemental rule.

Onshore natural gas processing facilities are proposed for inclusion due to the fact that these operations represent a significant emissions source, approximately 8 percent of fugitive, vented and incremental [6] combustion emissions from the natural gas segment, methods are available to estimate emissions, and there are a reasonable number of reporters. Most natural gas processing facilities proposed for inclusion in this supplemental proposed rulemaking would already be required to report under subpart C and/or subpart NN of the Final MRR.

Onshore Natural Gas Transmission Compression Facilities and Underground Natural Gas Storage

Natural gas transmission compression facilities move natural gas throughout the U.S. natural gas transmission system. Natural gas is also injected and stored in underground formations during periods of low demand (*e.g.,* spring or fall) and withdrawn, processed, and distributed during periods of high demand (*e.g.,* winter or summer). Storage compressor stations are dedicated to gas injection and extraction at underground natural gas storage facilities.

Vented and fugitive CH_4 emissions from reciprocating and centrifugal compressors, including compressor and station blowdowns, centrifugal compressor wet and dry seals, wet seal oil degassing vents, reciprocating compressor rod packing vents, unit isolation valves, blowdown valves, compressor scrubber dump valves, gas pneumatic continuous bleed devices and all other compressor fugitive emissions, are the primary CH_4 emission source from natural gas transmission compression stations and underground natural gas storage facilities.

Dehydrators are also a significant source of CH_4 emissions from underground natural gas storage facilities. While these are the major emissions sources in natural gas transmission, other potential sources include, but are not limited to, condensate (water and hydrocarbon) tanks, open-ended lines and valve stem seals. Condensate tank vents in transmission can be a significant source of emissions from malfunctioning compressor scrubber dump valves and will require detection of such leakage by an optical imaging instrument and direct measurement where found present.

Onshore natural gas transmission compression facilities and underground natural gas storage facilities are proposed for inclusion due to the fact that these operations represent significant sources of fugitive, vented and incremental [7] combustion emissions, 15 and 2 percent, respectively, methods are available to estimate emissions, and there are a reasonable number of reporters. Further, this segment was included in the initial proposed rule and EPA has made improvements to the proposal based on comments received.

LNG Import and Export and LNG Storage

The U.S. imports and exports natural gas in the form of LNG, which is received, stored, and, when needed, re-gasified at LNG import and export terminals. Import and export include both LNG movements between U.S. and foreign sources as well as transport between U.S. sources. LNG storage facilities liquefy and store natural gas from processing plants and transmission pipelines during periods of low demand (*e.g.,* spring or fall) and re-gasify for send out during periods of high demand (*e.g.,* summer and winter)

Fugitive and vented CH_4 and CO_2 emissions from reciprocating and centrifugal compressors, including centrifugal compressor wet and dry seals, wet seal degassing vents, reciprocating compressor rod packing vents, and all other compressor fugitive emissions, are the primary CH_4 and CO_2 emission source from LNG storage facilities and LNG import and export facilities. Process units at these facilities can include vapor recovery compressors to re-liquefy natural gas tank boil-off (at LNG storage facilities), re-condensers, vaporization units, tanker unloading equipment (at LNG import terminals), transportation pipelines, and/or LNG pumps.

LNG storage "facilities" can be defined as facilities that store liquefied natural gas in above ground storage tanks. LNG import terminal can be defined as onshore or offshore facilities that receive imported LNG via ocean transport, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to a natural gas transmission or distribution system. LNG export terminal (facility) can be defined as onshore or offshore facilities that receive natural gas, liquefy it, store it in storage tanks, and send out the LNG via ocean transportation, including to import facilities in the United States. EPA is proposing inclusion of these facilities because the National Inventory has very little data on methane emissions in these segments which are expected to grow substantially in forward years.

Petroleum and Natural Gas Pipelines

Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Crude oil transportation involves pump stations and bulk tank terminals to move crude oil through pipelines and loading and unloading crude oil tanks, marine vessels, and railroad tank cars. The majority of vented and fugitive emissions from the transportation of natural gas occur at the compressor stations, which are proposed for inclusion in the supplemental rule and discussed above.

EPA is not proposing to include reporting of fugitive emissions from natural gas pipeline segments between compressor stations, or crude oil pipelines and tank terminals in the supplemental rulemaking due to the dispersed nature of the fugitive emissions, and the fact that once fugitives are found, the emissions are generally addressed quickly. For natural gas gathering pipelines, EPA is proposing that producers who own or operate gathering lines associated with their production fields and natural gas processors who own or operate gathering lines associated with their processing plants should include those gathering lines in their field or processing plant reported emissions.

Natural Gas Distribution

Natural gas distribution facilities are local distribution companies (LDCs) that

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[6] The denominator includes total fugitive and vented emissions, as well as any additional combustion related emissions that will be required to be reported by the petroleum and natural gas industry and that wasn't already covered in the final MRR.

[7] The denominator includes total fugitive and vented emissions, as well as any additional combustion related emissions that will be required to be reported by the petroleum and natural gas industry and that wasn't already covered in the final MRR.

include the above grade (above ground) gas metering and pressure regulation (M&R) equipment, M&R equipment below grade in vaults, buried pipelines and customer meters used to transport natural gas primarily from high pressure transmission pipelines to end users. In the distribution segment, high-pressure gas from natural gas transmission pipelines enters a "city gate" station, which reduces the pressure and distributes the gas through primarily underground mains and service lines to individual end users. Distribution system CH_4 and CO_2 emissions result mainly from fugitive emissions from above ground gate stations (metering and regulating stations), below grade vaults (regulator stations), and fugitive emissions from buried pipelines. At gate stations, fugitive and vented CH_4 emissions primarily come from valves, open-ended lines, connectors, pressure safety valves, and natural gas driven pneumatic devices. CH_4 emissions in vaults are entirely fugitive, primarily from piping connectors to meters and regulators.

Although emissions from a single vault, gate station or segment of pipeline in the natural gas distribution segment may not be significant, collectively these emissions sources contribute a significant share of emissions from natural gas systems.

EPA proposes to include natural gas distribution facilities because these operations represent a significant emissions source, approximately 6 percent of fugitive, vented and incremental [8] combustion emissions from the petroleum and natural gas industry. EPA proposes that LDC's would report for all of the distribution facilities that they own or operate.

Crude Oil Transportation

Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations is storage tanks and pumping stations. The major sources of CH_4 and CO_2 emissions include releases from tanks and marine vessel loading operations.

EPA is not proposing to include the crude oil transportation segment of the petroleum and natural gas industry in this supplemental rulemaking due to its small contribution to total petroleum and natural gas CH_4 and CO_2 emissions, accounting for much less than 1 percent.

D. Selection of Reporting Threshold

EPA proposes that owners or operators of facilities with emissions equal to or greater than 25,000 metric tons CO_2e per year be subject to these reporting requirements. This threshold is applicable to all petroleum and natural gas system reporters covered by this subpart: onshore petroleum and natural gas production facilities, offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, including gathering/boosting stations; natural gas transmission compression facilities, underground natural gas storage facilities; LNG storage facilities; LNG import and export facilities and natural gas distribution facilities. As described above, under the proposed rule, for onshore petroleum and natural gas production facilities an owner or operator (as defined by the proposed rule) would evaluate emissions from all equipment covered by the proposed rule, including vented, fugitive, flared and stationary combustion, in a defined basin against the threshold to determine applicability.

Consistent with the rest of the Final MRR, EPA is proposing that for the purposes of determining whether a facility emits equal to or greater than a 25,000 $mtCO_2e$, a facility must include emissions from all source categories for which methods are provided in the rule. EPA proposes that when a facility determines emissions for the purposes of the threshold determination under subpart W, that the fuel combustion emissions estimates include both stationary and portable equipment (*e.g.,* compressors, drilling rigs, and dehydrators that are skid-mounted) that are controlled by well operators through ownership, direct operation, leased and rented equipment, and contracted operation. Fugitive, vented and combustion emissions from portable equipment are proposed for inclusion in the threshold determination for this source category due to the unique nature of the petroleum and natural gas industry. In addition to well drilling rigs and their ancillary equipment for well completions, it is common practice in onshore production to use skid mounted portable compressors, glycol dehydrators and other equipment partly for installation cost savings and partly because well flow rates decline over time and well-head equipment becomes over sized, and is moved around to match equipment capacity with wells of the same production capacity.

Also due to the unique nature of the industry, EPA believes that it may be possible that onshore petroleum and natural gas production equipment from onshore petroleum and natural gas production facilities may be co-located with other manufacturing facilities already covered under other subparts of the rule (*e.g.,* cement manufacturing facilities or glass manufacturing facilities). It is not EPA's intent to have these manufacturing facilities include emissions from onshore petroleum and natural gas production equipment in their threshold determination. EPA seeks comment on this approach.

To identify the most appropriate threshold level for reporting of emissions, EPA conducted analyses to determine emissions reporting coverage and facility reporting coverage at four different threshold levels: 1,000 metric tons CO_2e per year, 10,000 metric tons CO_2e per year, 25,000 metric tons CO_2e per year, and 100,000 metric tons CO_2e per year. Table W–2 provides coverage of emissions and number of facilities reporting at each threshold level for all the industry segments under consideration for this proposed supplemental rule.

TABLE W–2—THRESHOLD ANALYSIS FOR EMISSIONS FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

Segment	Total national emissions	Total number of facilities	Threshold level	Total emissions covered by threshold		Facilities covered	
	(metric tons CO_2e per year)			(metric tons CO_2e per year)	Percent	Number	Percent
Onshore Petroleum & Gas Production	277,798,737	27,993	100,000	187,175,289	67	466	2
			25,000	224,227,559	81	1,232	4

[8] The denominator includes total fugitive and vented emissions, as well as any additional combustion related emissions that will be required to be reported by the petroleum and natural gas industry and that wasn't already covered in the final MRR.

TABLE W–2—THRESHOLD ANALYSIS FOR EMISSIONS FROM THE PETROLEUM AND NATURAL GAS INDUSTRY—Continued

Segment	Total national emissions (metric tons CO_2e per year)	Total number of facilities	Threshold level	Total emissions covered by threshold (metric tons CO_2e per year)	Total emissions covered by threshold Percent	Facilities covered Number	Facilities covered Percent
			10,000	242,390,849	87	2,413	9
			1,000	268,848,529	97	10,604	38
Offshore Petroleum & Gas Production	11,261,305	3,235	100,000	3,242,389	29	4	0
			25,000	5,119,405	45	58	2
			10,000	7,111,563	63	184	6
			1,000	10,553,889	94	1192	37
Natural Gas Processing	33,984,015	566	100,000	24,874,783	73	130	23
			25,000	31,229,071	92	289	51
			10,000	32,982,975	97	396	70
			1,000	33,984,015	100	566	100
Natural Gas Transmission Compression	64,059,125	1,944	100,000	34,518,927	54	433	22
			25,000	57,683,144	90	1,145	59
			10,000	62,672,905	98	1,443	74
			1,000	64,051,661	100	1,695	87
Underground Natural Gas Storage	9,713,029	397	100,000	3,548,988	37	36	9
			25,000	7,846,609	81	133	34
			10,000	8,968,994	92	200	50
			1,000	9,696,532	100	347	87
LNG Storage	2,113,601	157	100,000	695,459	33	4	3
			25,000	1,900,793	90	33	21
			10,000	2,030,842	96	41	26
			1,000	2,096,974	99	54	34
LNG Import and Export [2]	315,888	5	100,000	314,803	99.7	4	80
			25,000	314,803	99.7	4	80
			10,000	314,803	99.7	4	80
			1,000	315,888	100.00	5	100
Natural Gas Distribution	25,258,347	1,427	100,000	18,470,457	73	66	5
			25,000	22,741,042	90	143	10
			10,000	23,733,488	94	203	14
			1,000	24,983,115	99	594	42

[1] The emissions include fugitive and vented CH_4 and CO_2 and combusted CO_2, N_2O, and CH_4 gases. The emissions for each industry segment do not match the 2008 U.S. Inventory either because of added details in the estimation methodology or use of a different methodology than the U.S. Inventory. For additional discussion, refer to Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923).

[2] The analysis included only import facilities. There is only one export facility, located in Kenai, Alaska.

EPA is proposing a threshold of 25,000 metric tons CO_2e applied to those emissions sources listed in Table W–2, which will cover approximately 83 percent of estimated vented and fugitive emissions and incremental combustion emissions from facilities that did not meet the reporting requirements under Subpart C alone, from the entire petroleum and natural gas industry, while requiring only a small fraction of total facilities to report. For additional information, please refer to Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923). For specific information on costs, including unamortized first year capital expenditures, please refer to section 4 of the Economic Impact Analysis.

Although EPA is proposing an emissions threshold of 25,000 $mtCO_2e$ for all segments of the petroleum and natural gas industry, EPA is taking comment on whether a 10,000 $mtCO_2e$ threshold for onshore petroleum and natural gas production would be more appropriate.

For onshore petroleum and natural gas production, EPA is proposing that portable and stationary fuel combustion emissions be included in the threshold determination due to the large percentage of emissions from portable equipment in the petroleum and natural gas industry. EPA considered lowering the threshold to 10,000 $mtCO_2e$ and excluding portable equipment from the threshold determination (and reporting), however, data were not available to distinguish portable and stationary combustion emissions in order to evaluate the lower threshold considering just stationary combustion emissions.

Secondly, for onshore petroleum and natural gas production, EPA is proposing that owners or operators report at the basin level. EPA is seeking comment on owners or operators reporting at the field level. Although EPA believes that a 25,000 $mtCO_2e$ threshold is appropriate for the basin level approach, as described above, EPA seeks comment on whether the threshold should be lowered to 10,000 $mtCO_2e$ if reporting were to be at the field level. Table W–3 presents the emissions and facility coverage for a field level definition for onshore petroleum and natural gas production.

TABLE W–3—EMISSIONS COVERAGE AND ENTITIES REPORTING FOR FIELD LEVEL FACILITY DEFINITION

Threshold level [2]	Emissions covered		Facilities covered	
	Metric tons CO_2e/year	Percent	Number	Percent
100,000	99,776,033	38	305	0
25,000	144,547,282	55	1,253	2
10,000	169,160,462	64	2,846	3
1,000	242,621,431	92	39,652	48

In addition to seeking comment on the proposed threshold for onshore production, EPA more broadly is seeking comment on the selection of the threshold for all segments of the petroleum and natural gas industry.

E. Selection of Proposed Monitoring Methods

Many domestic and international GHG monitoring guidelines and protocols include methodologies for estimating emissions from petroleum and natural gas operations, including the 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), and corporate industry protocols developed by the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association. The methodologies proposed vary by the emissions source and the level of accuracy desired in the estimation.

EPA has carefully considered possible options to estimate emissions from every emission source proposed for reporting. EPA has proposed to use the most appropriate method taking into account both the cost to the reporter as well as accuracy of emissions achieved through the proposed method. Overall, we propose the following types of monitoring methods: (1) Direct measurement to develop site and source-specific emission factors; (2) engineering estimation; (3) combination of direct measurement and engineering estimation; (4) leak detection and use of leaker emission factor; and (5) population count and population emission factors. Table W–4 of this preamble provides a list of the emissions sources to be reported with the corresponding monitoring methods.

A monitoring method proposed for a specific source is to be used across all reporting segments of the petroleum and gas system. Two exceptions to this are: (1) For tanks in onshore natural gas transmission facilities that exhibit gas bypass from scrubber dump valves, EPA is proposing to require direct measurement under the proposal, whereas in other segments under the proposal, the emissions from tanks would be required to be estimated using E&P Tank simulation software; and (2) under the proposal, fugitive emissions from onshore petroleum and natural gas production and inaccessible to plain view (buried or below grade in vaults) emissions in gas distribution would require estimation using population emissions factors as opposed to other segments' fugitive emissions that require leak detection and the use of leaker emissions factors. Finally, offshore petroleum and natural gas production platforms would be required under the proposal to use methods provided by the most recent GOADS reporting system. This means that Federal Gulf of Mexico platforms would report emissions already being calculated and reported to MMS as a part of the GOADS study and the remaining platforms that are not a part of the GOADS study (*i.e.,* platforms in all state waters and other Federal waters outside the Gulf of Mexico) would be required to adopt the GOADS methodology.

TABLE W–4. SOURCE SPECIFIC MONITORING METHODS AND EMISSIONS QUANTIFICATION

Emission source	Monitoring methods	Emissions quantification methods
Natural Gas Pneumatic Bleed Devices (High or Continuous).	Engineering Estimation	Manufacturer device model bleed rate and engineering calculation.

TABLE W–4. SOURCE SPECIFIC MONITORING METHODS AND EMISSIONS QUANTIFICATION—Continued

Emission source	Monitoring methods	Emissions quantification methods
Natural Gas Pneumatic Bleed Devices (Low)	Component Count	Population emissions factor.
Natural Gas Driven Pneumatic Pump Venting	Engineering Estimation	Manufacturer model emissions per unit volume and volume pumped.
Acid Gas Removal Vent Stacks (CO_2 only)	Engineering Estimation	Engineering Calculation and flow meters.
Dehydrator Vent Stacks	Engineering Estimation	GlyCalc simulation software.
Well Venting for Liquids Unloading	(1) Engineering Estimation or (2) Direct Measurement.	(1) Field specific emission factor times events or (2) Flow metered emission factor times events.
Gas Well Venting during Completions or Workovers.	(1) Engineering Estimation, or (2) Direct Measurement.	(1) Field specific emission factor times events or (2) Flow metered emission factor times events.
Blowdown Vent Stacks	Engineering Estimation	Equipment specific emission factor and number of events.
Storage Tanks (Onshore Production and Processing).	Engineering Estimation	E&P Tank equipment specific emission factor times throughput.
Storage Tanks (Transmission)	Direct Measurement	Flow metered emission factor time operating hours.
Well Testing Venting and Flaring	Engineering Estimation	Gas to oil Ratio (GOR); flow rate.
Associated Gas Venting and Flaring	Engineering Estimation	Gas to oil Ratio (GOR); flow rate.
Flare Stacks	(1) Direct Measurement or (2) Engineering Estimation.	Engineering Calculation.
Centrifugal Compressor Wet Seal Oil Degassing Vent.	Direct Measurement	Flow metered equipment specific emission factor times operating hours.
Large Reciprocating Compressor Rod Packing Vents.	Direct Measurement	Flow metered equipment specific emission factor times operating hours.
Large Compressor Blowdown Valve Leak	Leak Detection with optical gas imaging instrument.	Flow metered equipment specific emission factor times operating hours.
Large Compressor Blowdown Vent (Unit Isolation Valve Leak).	Leak Detection with optical gas imaging instrument.	Flow metered equipment specific emission factor times stand-by depressurized hours.
Fugitive Sources (Processing, Transmission, Underground Storage, LNG Storage, LNG Import Export, LDC).	Leak Detection with optical gas imaging instrument.	Leaker emission factors times detected leaks.
Fugitive Sources (Onshore Production, LDC)	Component Count	Population Emission Factors times components.

1. Direct Measurement

EPA is proposing to require five sources in this supplemental proposal to directly measure emissions: storage tanks (transmission) when scrubber dump valves are detected leaking, centrifugal compressor wet seal oil degassing vents, large reciprocating compressor rod packing vents, large compressor blowdown vent valve leaks, and large compressor blowdown vent (unit isolation valve leaks), the latter two when leakage is detected. For example, storage tanks in the onshore natural gas transmission segment typically store the condensate (water, light hydrocarbons, seal oil) from the scrubbing of pipeline quality gas. The volume and composition of liquid is typically low and variable, respectively, in comparison to the volumes and composition of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are considered insignificant. However, scrubber dump valves malfunction or stick-open due to debris in the condensate and can remain open resulting in natural gas bypass via the open dump valve to and through the condensate tank, and therefore the use of E&P Tanks and other models are not applicable to tanks in the transmission segment. The only potential option for measuring emissions from scrubber dump valves is to monitor storage tank emissions with a gas imaging camera to determine if the emissions do not subside and become negligible when dump valves close. If the scrubber dump valve is stuck and leaking natural gas through the tank then the emissions will be visibly significant and will not subside to inconspicuous volumes. If the scrubber dump valve functions normally and shuts completely after the condensate has been dumped then the storage tank, emissions should subside and taper off to insignificant quantities. If emissions are detected to be continuous for a duration of five minutes then a one-time measurement would be required using a temporary meter to establish an equipment specific emission factor.

This proposal is based on the fact that the emissions magnitude from these five sources are significant enough to warrant reporting for the supplemental proposed rule and that no credible engineering estimation methods or emissions factors exist that can accurately characterize the emissions. There are several public reference studies and guidance documents that provide emissions factors for these sources. However, after close review, EPA has determined that these emissions factors cannot uniquely characterize the emissions specifically from individual equipment or a facility. For example, the emissions from wet seal degassing and rod packing are directly correlated to the size of the compressor, throughput, and the operating time of the compressor in the reporting year. Also, in the case of unit isolation valves and compressor blow down valves the emissions magnitude varies depending on operational and maintenance practices as valves can have excessive leakage, especially when a compressor is not in operation. These factors do not get accounted for using an emissions factor.

The proposed supplemental rule would require that rod packing and blowdown valves be measured for emissions both in operating as well as standby pressurized modes. In addition, unit isolation valve leaks would be required to be measured at the blowdown vent in the standby depressurized mode. To correctly quantify emissions from centrifugal and large reciprocating compressors the proposal would require that, for each compressor, one measurement be taken in each of the operational modes that occurs during a reporting period: (i) Operating, (ii) standby pressurized, and (iii) not operating, depressurized. Depending on the operational practices each mode could have significantly different emissions and would need to be separately quantified as a part of the proposed rule.

For direct measurement, EPA proposes that the following technologies be used: high volume samplers, meters (such as rotameters, turbine meters, hot wire anemometers, and others), and/or calibrated bags. EPA recognizes that different measurement equipment would be required for different source emissions measurement depending on the configuration of the system. Hence the proposed rule provides these options for multiple direct measurement equipment, but the reporter must calibrate and maintain the equipment based on either consensus based standards or an appropriate method specified by the equipment manufacturer, as specified in the proposed rule. Where a vent emission source cannot be accessed on the ground or from a fixed platform, the reporter has the choice of using a man-lift or installing either a permanent or temporary vent line access port through which a meter can be inserted to measure flow or velocity. If emissions exceed the maximum range of one measurement instrument, the reporter would be required to use a different instrument option that can measure larger magnitude emissions levels. For example, if a high volume sampler maximum rate is exceeded by an emissions source, then emissions would be required to be directly measured using either calibrated bagging or a meter. CH_4 and CO_2 emissions from the emissions stream would be required to be calculated using the composition of the gas in the process equipment (compressor).

2. Engineering Estimation

This proposed rule would require two main types of engineering calculation methods for emissions; (1) volumetric calculation method, and (2) engineering first principle methods.

(1) Volumetric Calculation Method

The volumetric calculation method has been proposed for calculating CH_4 and CO_2 vent emissions from sources where the variable in the emissions magnitude on an annual basis is the number of times the source releases CH_4 and CO_2 emissions to the atmosphere. In addition, the estimation of the total volume of emissions is a matter of simple arithmetic calculation without the need for complex calculations. For example, when a compressor is taken offline for maintenance, the volume of CH_4 and CO_2 blowdown vent emissions that are released is the same during each release, is easily calculable, and the only variable is the number of times the compressor is taken offline and vented.

(2) Engineering First Principle Methods

Emissions from sources such as tanks and glycol dehydrators can be reliably calculated using standard engineering first principle methods such as those available in E&P Tank and GlyCalc. The use of such standard and readily available software is a cost-effective way to uniformly estimate emissions that are representative for the two sources. To maintain standardization across reporters the proposed rule would require the use of E&P Tank for estimating the emissions from well-pad separator conditions when flashed to atmospheric pressure in any downstream stock tank, and GlyCalc for glycol dehydrators.

E&P Tank is available for free and GlyCalc can be purchased at a small fee. Also, these two software models are widely used in the industry and the operation of the software is well understood. Using such software also addresses safety concerns that are associated with direct measurement from the two sources. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions. EPA seeks comment on whether there are additional or alternative software packages to E&P Tank and GlyCalc that should be required to be used to calculate emissions.

In cases where tank emissions do not represent equilibrium conditions of the liquid in a gas-liquid separator and no publicly available data are available on vapor bypass direct measurement would be required under the proposal. For pressurized liquids sent to atmospheric storage tanks where tank emissions are not expected to be represented by the equilibrium conditions of the liquid in a gas-liquid separator as calculated by the E&P Tank Model, then emissions calculated by E&P Tank would be multiplied by an empirical factor.

The supplemental proposed rulemaking does not include emissions from tanks containing primarily water with the exception of transmission station condensate tanks where dump valve are determined to be bypassing gas. Therefore, EPA seeks comments on how to quantify emissions from tanks storing water without resulting in additional reporting burden to the facilities.

For further discussion of these software programs and emissions calculation methods, refer to Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923).

3. Combination of Direct Measurement and Engineering Estimation

Several sources provide a choice between engineering estimation based on operating data and direct measurement (if meters are already installed). For continuous flaring, a one-time direct measurement or engineering estimate may be performed in conjunction with engineering estimation based on operating data that relates to the quantity of flared gas. For well completion venting and well workover venting (each during flowback after hydraulic fracturing, the only significant well completion emissions), EPA explored the possibility of using a meter for measuring hydrocarbon gas lost during these venting events which may last from one to ten days. Some companies have reported directly measuring these emissions under certain circumstances. However, such metering could be technically challenging, if not impossible, and also burdensome given the number of well completions and workovers being conducted on an annual basis.

It is important to note, however, that no body of data has been identified that can be summarized into generally applicable emissions factors to characterize emissions from these sources in each unique field. In fact, the emissions factor being used in the 2008 U.S. GHG Inventory is believed to significantly underestimate emissions based on industry experience as included in the Natural Gas STAR Program publicly available information (*http://www.epa.gov/gasstar/*). In addition, the 2008 U.S. GHG Inventory emissions factor was developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country.

As a result, EPA proposes the development of a field-specific emission factor either by direct measurement of flow rate of hydrocarbons using a meter or by an engineering estimation based on well choke pressure drop. Given the large number of well completions and well workovers, EPA proposes that one representative well completion and one well workover per field horizon be developed to characterize emissions per day of venting from all other completions and workovers in that field horizon. The reporter would be required to update this factor every two years. This would alleviate burden but at the same time achieve a reasonable characterization of the emissions from these two sources.

5. Use of Leak Detection and Leaking Component Emission Factors

Each segment of the petroleum and gas system has a variety of fugitive emissions sources that at a source type level have low emissions volume, but combined together at a segment level contribute significantly towards the total emissions from petroleum and gas systems. EPA considered several options for estimating emissions from fugitive emissions sources. One option considered was to use a population count of each fugitive emissions source (*e.g.,* source types such as valves, connectors, *etc.*) and multiply it by a population emissions factor. This option would not account for differences in operational and maintenance practices among facilities. If population emissions factors are used then the fugitive emissions from a particular facility will remain constant indefinitely until the facilities are modified (*i.e.,* change the population of equipment) or new factors are provided. This approach also will not account for fugitive emissions reduction measures the industry has undertaken in the last few years since the population emission factors were developed. Facilities with good maintenance practices may have fugitive emissions lower than the population emission factors. As described further below, EPA requests comment on the use of emission factors and ways in which these shortcomings may be overcome.

Another option considered was the use of fugitive emissions detection (*e.g.,* an infrared camera) and direct measurement (*e.g.,* calibrated bags or high volume samplers) for fugitive sources. This option may be more cost-effective when the sources of fugitive emissions are in a relatively small geographic area such as at a processing plant, gas compressor station, or distribution gate station. This approach, however, could be less cost effective for widely dispersed sources (*e.g.,* well pads and gathering lines).

Hence, to overcome these issues, EPA proposes conducting fugitive emissions detection and then applying leaking component (or leak only) emissions factors for processing, transmission, underground storage, LNG storage, LNG import and export terminals, and LDC gate stations. The fugitive emissions leak detection method does not require corresponding direct measurement of the fugitive emissions, which is significantly more burdensome than fugitive emissions detection using the most modern optical gas imaging instrument detection technology. This method is an improvement over the use of population emissions factors because the factors were developed for leaking components and applied only to leaking components, leading to a more accurate calculation of emissions from each piece of equipment. Several commenters to the initial proposed rule recommended leak detection with an optical gas imaging instrument and quantification with emission factors. In addition, leaking component emissions factors are applied only to those emissions sources that are determined to be emitting as a result of the fugitive emissions detection process.

EPA analyzed new fugitive leak studies specifically performed on natural gas facilities in processing plants and transmission compressor stations, as recommended by several Subpart W initial proposed rule commenters. Leaking component emissions factors from these studies were compared with other studies (see below). EPA found that emission factors generated from the Clearstone studies related better to methane-rich stream fugitives and were more appropriate than other emission factors developed for highly regulated refinery and petrochemical plants on VOC emissions. Therefore, EPA is using emissions data from the Clearstone studies as the basis for the leaker factors proposed in this rule. EPA requests comments on the use of emission factors from the Clearstone studies. For further details see Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA–HQ–OAR–2009–0923).

Emission References for Petroleum and Natural Gas Systems

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API. *Emission Factors for Oil and Gas Production Operations.* Table 8, page 10. API Publication Number 4615. January 1995.

EPA. Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants. Clearstone Engineering Ltd. June 20, 2002. *http://www.epa.gov/gasstar/documents/four_plants.pdf.*

EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007.* Annexes. Tables A–112–A–125. U.S. EPA. April 2009. *http://epa.gov/climatechange/emissions/downloads09/Annexes.pdf.*

EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. U.S. EPA 2006. *http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.*

EPA. *Protocol for Equipment Leak Emission Estimates.* Emission Standards Division. U.S. EPA. SOCMI Table 2–7. November 1995. *http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.*

GRI. *Methane Emissions from the Natural Gas Industry.* Volume 6. Table 4–2 and Appendix A, page A–2. June 1996. *http://www.epa.gov/gasstar/documents/emissions_report/6_vented.pdf.*

GRI. Methane Emissions from the Natural Gas Industry. Volume 8. Tables 4–3, 4–6 and 4–24. June 1996. *http://www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf.*

GRI. *Methane Emissions from the Natural Gas Industry.* Volume 9. Tables 8–9 and 9–4. June 1996. *http://www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf.*

GRI. *Methane Emissions from the Natural Gas Industry.* Volume 10. Table 7–1. June 1996. *http://epa.gov/gasstar/documents/emissions_report/10_metering.pdf.*

ICF. Estimates of Methane Emissions from the U.S. Oil Industry. Draft. Page 13. October 1999.

Clearstone. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems.* Clearstone Engineering Ltd., Enerco Engineering Ltd., and Radian International. Pages 61–63. May 25, 1998.

National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd.; Innovative Environmental Solutions, Inc. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* For EPA Natural Gas STAR Program. March 2006.

Clearstone. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems.* Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. 2007.

EPA considered the use of the three major types of emissions detection equipment: optical gas imaging instruments, IR laser detector instruments and Toxic Vapor Analyzers (TVA) or Organic Vapor Analyzers (OVA). Optical gas imaging instruments are able to scan hundreds of source types quickly, allowing for the most efficient survey of emissions at a broad range of facilities. In addition, EPA recently adopted detailed performance standards for the optical gas imaging camera in the *Alternative work practice for monitoring equipment leaks (AWP) (40 CFR part 60 subpart A § 60.18(i)(1) and (2)).* We recognize that the purchase of optical gas imaging instruments can be costly, especially for smaller facilities. However, EPA believes that most facilities will opt for contractors to conduct emissions detection once per year. As mentioned above, several commenters to the initial proposed rule recommended leak detection with an optical gas imaging instrument in accordance with the EPA AWP. Hence, the supplemental proposed rule requires the use of an optical gas imaging instrument compliant with the operational requirements of the EPA AWP. In contrast to the EPA AWP, however, the proposed rule does not require multiple surveys per year and does not require leak repair. As discussed further below, for this proposed rule, EPA requires comprehensive annual leak detection of the fugitive emissions sources specified in the proposed rule. The proposed supplemental rule does not allow for the use of an OVA/TVA. The OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. In addition, the OVA/TVA range is limited to the reach of an operator standing on the ground or fixed platform, thus excluding all emissions out of reach. However, EPA is seeking comments on allowing the OVA/TVA to be used as another option to the optical imaging camera in this proposed rule.

EPA is aware that the optical gas imaging instrument's "detection sensitivity levels" as required by the AWP were established from data on volatile organic compound (VOC) emissions from petroleum refineries and chemical plants. The optical gas imaging instrument has been used extensively to successfully detect methane emissions in the petroleum and gas industry by petroleum and gas companies. A 2006 independent study funded through a grant by EPA and conducted by Clearstone Engineering, was an extensive study of methane emissions in gas processing plants and upstream gathering compressor stations and well sites. Method 21 was employed to detect leaks and HiFlow samplers were used to determine the emissions from those leaks. This study surveyed approximately 74,000 components finding 3,650 leaks (4.9 percent). Of these leaks, 497 (<1 percent of total components) contributed 90 percent of the total fugitive emissions. The smallest of the 497 leaks was 177 grams per hour, so an optical gas imaging instrument should be able to adequately image methane leaks since the smallest leak was well above the 60 to 100 gram per hour detection sensitivity in Table 1 of the AWP. Therefore, for the purposes of this reporting rule, EPA determined that an optical gas imaging instrument that meets the detection sensitivity requirements of the AWP for any monitoring frequency as specified in Table 1 of the AWP, is acceptable for use under this proposed rule. Leak detection and leaker emission factors only apply 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.

The proposed rule requires that the survey for fugitive emissions detection be comprehensive. This means that, on an annual basis, the entire population of fugitive emissions sources proposed for reporting in this rule would be surveyed at least once. EPA proposes that emissions are quantified using leaker emissions factors. Under the proposal, if a component fugitive emission is detected, emissions are assumed to occur the entire 365 days in the year.

EPA is aware that the petroleum and natural gas industry is already implementing voluntary fugitive emissions detection and repair programs. Such voluntary programs are useful, but pose an accounting challenge with respect to emissions reporting for this proposed rule. The proposed approach does not preclude any owner or operator from detecting and repairing fugitive emissions prior to quantifying emissions for the purposes of reporting under this proposed rule.

To address this issue, EPA considered, but did not propose, requiring a facility to conduct multiple surveys and to report emissions using the appropriate leaker factors. Under this approach, if a specific emission source is found not leaking in the initial survey but leaking in subsequent surveys, emissions would be quantified from the date of the first survey where a leak was detected forward through the time when the leak is fixed, or the end of the year, whichever is first. Similarly, if an emissions source is found to be leaking in the initial survey, emissions would be quantified from the date of that survey through to when the leak is repaired, or the end of the year, whichever is first. Under this approach, emissions would reflect leak reductions as determined by repairs and follow-up detection surveys

EPA seeks comment on whether this alternative approach better estimates annual facility emissions without resulting in additional reporting burden to the facilities. Further, we seek comment on whether, if implemented, multiple surveys should be optional or required for owners or operators.

6. Use of Population Count and Population Emission Factor

Fugitive emissions detection and use of leaking component emissions factors are not always cost effective and can be burdensome. This is particularly true of onshore petroleum and natural gas production where the fugitive sources are spread out across large geographical areas and fugitive emissions are a minor contributor to total segment emissions. In the distribution segment, pipeline fugitive emissions are a large fraction of total emissions, but the pipelines are buried where leaks are difficult to detect. Similarly, metering/regulator stations, which are an important source of fugitive emissions, are sometimes located inside underground vaults that are difficult to access. In such scenarios, fugitive emissions detection can be burdensome. Therefore, for onshore petroleum and natural gas production, gas gathering pipelines and LDC pipelines and M&R stations below grade in vaults, the proposed rule requires the use of population count of emissions sources and population emissions factor to estimate fugitive emissions. Population count and population emission factors only apply 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. EPA is using emissions data from studies listed in the Emission References (#2, #4, #5, #7, #8, #9 above) as the basis for the population emissions factors proposed in this rule. However, the API compendium emissions factors that we are proposing to use in the upstream oil and gas production sector may be underestimating emissions. EPA seeks comment on how to improve these factors and/or collect more accurate data.

7. Alternative Monitoring Methods Considered

Before selecting the monitoring methods proposed above, we considered additional measurement methods. The use of Method 21 was considered for fugitive emissions detection and measurement. Although Toxic Vapor Analyzers (TVA) and Organic Vapor Analyzers (OVA) were considered they were not proposed for fugitive emissions detection and quantification.

Method 21. This is the reference method for equipment leak detection and repair regulations for volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions under several 40 CFR part 60, 40 CFR part 61, 40 CFR part 63, and 40 CFR part 65 emission standards. Petroleum refineries, chemical plants and large gas processing plants are required under state and federal laws to perform LDAR (Leak Detection and Repair) to control VOC air pollution emissions. LDAR programs require VOC and/or HAP leak detection using instruments specified in Method 21, and requires repair of leaks if the rate is above the leak definitions specified within the specific regulation (typically between 500 parts per million to 10,000 parts per million as read on an OVA). Some states and air quality districts have lower leak definitions than the Federal standards. LDAR programs require facilities to conduct multiple surveys per year: either following equipment-specific frequencies using VOC monitoring instruments, or bi-monthly, semi-quarterly or monthly using an optical gas imaging instrument, frequency depending on the sensitivity detection of the instrument. While LDAR programs do not require quantification, state inventories of air emissions use this LDAR leak detection data with "leaker" factors developed by the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) to estimate the quantity of VOC emissions. These factors were developed from petroleum refinery and petrochemical plant data using Method 21. SOCMI factors adjusted for methane content are considerably lower than the methane factors proposed in this rule, which were developed from more recent studies of gas processing plants and compressor stations.

The Federal LDAR program recently adopted an alternative work practice that allows use of optical gas imaging instruments in place of the VOC monitoring instrument specified in Method 21. In a similar vein, this rule proposes the use of optical gas imaging instruments to detect leaks once per year, and has developed leaker factors specific to methane from several recent studies quantifying component leaks in petroleum and gas facilities. While this rule proposes a similar approach to Method 21, given that this is a reporting rule for collecting annual GHG emissions, there are several key differences: the proposed annual reporting rule is focused on gathering fugitive and vented CO_2 and CH_4 emissions, does not require multiple surveys per year, and does not allow measurement using an OVA/TVA for the reasons cited above. Optical gas imaging instruments were found to be more appropriate for leak detection for the proposed supplemental rule as these instruments are able to scan hundreds of source components quickly, including components out of reach for an OVA/TVA.

Mass Balance for Quantification. Except in one case, EPA considered, but decided not to propose, the use of a mass balance approach for quantifying emissions across an entire facility. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. However, for pipeline transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings, the highly variable line pack of high pressure gas and the large volumes of throughput relative to emissions.

EPA is proposing this approach in the case of one emission source—acid gas recovery units. Typically, the natural gas volumes and compositions are measured both at the inlet and outlet of the acid gas recovery units as it is required to ensure that natural gas meets transmission system pipeline specifications. Hence, it is considered sufficiently feasible to use the mass balance approach for this source. For all other facilities and sources, the accuracy required in volume measurements will be a significant added burden in addition to being unreliable in many cases.

F. Selection of Procedures for Estimating Missing Data

The proposal requires data collection for a single source a minimum of once a year. If data are lost or an error occurs during emissions detection and/or measurement or calculation, the operator would be required to carry out the detection, direct measurement, and/or calculation a second time to obtain the relevant data point(s) as soon as the missing data are discovered. If this falls outside of the reporting year (*e.g.* between the end of the reporting year and the date when the emissions must be reported) the operator would be required to perform the necessary data development and report the results for the previous year. This prior year's lost data replacement could not be used as the one-time data collection for the current year. Where missing data procedures are used for the previous year, at least 30 days would be required to separate emissions estimation and/or measurements for the previous year and emissions estimation and/or measurements for the current year of data collection in order to better represent emissions estimates for different years. Similarly, engineering estimates would account for relevant source counts and frequency from the previous reporting period.

G. Selection of Data Reporting Requirements

EPA proposes that emissions from the petroleum and natural gas industry be reported on an annual basis. The reporting should be by the owner or operator of the facility as defined in the supplemental rule. Emissions from each source type at the facility would be required to be aggregated for reporting, with a few exceptions for field level reporting (*e.g.,* well completions and well workovers). For other equipment, unit-level reporting would not be required. For example, the owner or operator with multiple reciprocating compressors in an onshore production basin would be required to report emissions collectively from all rod packings on all cylinders from all compressors for all fields in that basin as specified in this proposed rulemaking. Generally, EPA has proposed that onshore production be reported at the basin level, as opposed to the unit or field level, to minimize reporting burden. EPA notes that in a concurrent proposed rulemaking for facilities that conduct CO_2 injection or geologic sequestration (subpart RR), the term "facility" is defined at a more disaggregated level, specifically as a "well or group of wells." EPA seeks comment on the use of more disaggregated reporting options for subpart W.

Emissions from all sources proposed for monitoring, whether in operating condition or on standby, would have to be reported. Any emissions resulting from standby compressor sources would be separately identified from the aggregate emissions.

The owner or operator would be required to report the following information to EPA as a part of the annual emissions reporting: fugitive, vented and flare combustion emissions monitored at an aggregate source level (unless specified otherwise), emissions from standby sources; and activity data for each aggregate source type level. Owners or operators of natural gas distribution facilities would report emissions at the individual station level.

Additional data are proposed to be reported to support verification: Engineering estimate of total component count; total number of compressors and average operating hours per year in each mode of operation for compressors, if applicable; minimum, maximum and average throughput per year; and specification of the type of any control device used, including flares. For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both is proposed to be reported. For compressors specifically, EPA proposes that the total number of compressors of each type (reciprocating, centrifugal with dry seals and centrifugal with wet seals) and average operating hours per year be reported.

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

H. Selection of Records That Must Be Retained

The owner or operator shall retain relevant information associated with the monitoring and reporting of emissions to EPA for three years as follows: Throughput of the facility when the emissions direct measurement was conducted; date(s) of measurement, detection and measurement instruments used, if any; and results of the emissions detection survey, including a video record of the leak survey.

A full list of records proposed to be retained is included in proposed 40 CFR part 98, subparts A and W.

III. Economic Impacts of the Proposed Rule

This section of the preamble examines the costs and economic impacts of this proposed supplemental rule, including the estimated costs and benefits of the rule, and the estimated economic impacts of the rule on affected entities, including estimated impacts on small entities. Complete details of the economic impacts of the final rule can be found in the text of the Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions under Subpart W Supplemental Rule (EPA–HQ–OAR–2009–0923). In brief, all equipment and labor activities for complying with each emissions estimate in the rule were analyzed by technical experts with relevant industry experience. The estimated labor hours and labor categories were applied to each industry segment, in some cases proportioned to small, medium and large facilities where such variation exists, to quantify the total labor hours, multiplied by Government statistics on labor rates, arriving at the total labor and equipment costs for the estimated numbers of sources. Administrative costs for reviewing the reporting rules, training personnel, documenting emissions data and emissions estimates, approving the submission to the EPA, submitting reports and maintaining records were included for each reporting company. These total bottom-up cost estimates were divided by the emissions captured to arrive at the dollar per metric ton, and divided by the number of reporting entities to arrive at average costs per entity. The methods proposed by EPA are a balance between minimizing these costs, maximizing emissions coverage and maximizing quality of emissions estimates. The cost to affected parties on a dollar per metric ton has been reduced by greater than 50 percent when compared to the initial petroleum and natural gas proposal. To achieve this cost reduction, EPA significantly modified the rule to rely significantly less on direct measurement and more on engineering estimates, leaker factors and emissions factors. Table W–5 and Table W–6 compare the first year and subsequent year costs, respectively, to reporters for reporting fugitive and vented emissions based on the reporting requirements proposed under the initial proposal as compared to the new supplemental proposed rule.

TABLE W–5—ESTIMATED FIRST YEAR COST FOR REPORTING FUGITIVE AND VENTED EMISSIONS FOR PETROLEUM AND NATURAL GAS SYSTEMS, $MMTCO_2E$

Segment	Initial proposed rule[1]		New supplemental proposed rulemaking	
	Cost ($million)	Cost per tonne ($/tonne)	Cost ($million)	Cost per tonne ($/tonne)
Original six segments	$32.5	$0.38	$26.7	$0.28
Onshore Production	NA	NA	27.7	0.18
Natural Gas Distribution	NA	NA	1.6	0.07
Total Segments	32.5	0.38	56.0	0.21

[1] The costs for the initial proposed rule, shown here, reflect the in-house monitoring option. Costs for the alternative contractor monitoring option can be found in Docket EPA–HQ–OAR–2008–0508–0138.

TABLE W–6—ESTIMATED SUBSEQUENT YEAR COST FOR REPORTING FUGITIVE AND VENTED EMISSIONS FOR PETROLEUM AND NATURAL GAS SYSTEMS, $MMTCO_2E$

Segment	Initial proposed rule		New supplemental proposed rulemaking	
	Cost ($million)	Cost per tonne ($/tonne)	Cost ($million)	Cost per tonne ($/tonne)
Original six segments	$28.1	$0.33	11.8	$0.13
Onshore Production	NA	NA	8.6	0.06
Natural Gas Distribution	NA	NA	1.0	0.04

TABLE W–6—ESTIMATED SUBSEQUENT YEAR COST FOR REPORTING FUGITIVE AND VENTED EMISSIONS FOR PETROLEUM AND NATURAL GAS SYSTEMS, $MMTCO_2E$—Continued

Segment	Initial proposed rule		New supplemental proposed rulemaking	
	Cost ($million)	Cost per tonne ($/tonne)	Cost ($million)	Cost per tonne ($/tonne)
Total Segments	$28.1	$0.33	21.4	0.08

[1] Subsequent year in the initial proposed rule was defined as Year 2 whereas in the supplemental proposed rule it is defined as the average of Years 2, 3, and 4.

A. How were compliance costs estimated?

1. Summary of EPA's Consideration of Comments Received on the Initial Proposal

A majority of the comments received on the compliance costs of the fugitive emissions reporting rule focused on facility level costs for detection and measurement of emissions. Commenters noted that costs estimated for certain petroleum and gas industry segments ignored available data on average leak factors. Some who commented specifically referred to government programs that gather similar, or in the case of offshore petroleum and gas production in the Gulf of Mexico Federal waters, some of the same data as required under Subpart W. Others who commented noted that Subpart W had higher estimated compliance costs than other sectors for much smaller GHG emissions.

EPA recognizes that the costs presented for some petroleum and gas industry segments in the initial proposal were relatively high for smaller emissions quantified than other industry sectors. EPA also recognizes that for many fugitive and vented emissions sources, new data exist on component emission factors, and long established data may be justified for smaller, inaccessible to plain view or more burdensome to identify emission sources. Furthermore, EPA recognizes that other government programs gather similar or the same data as proposed by this rule.

This proposed supplemental rule incorporates a number of different methodologies to provide improved emissions coverage at a lower cost burden to affected facilities. The approach used in determining the appropriate methodology for the supplemental was to minimize the use of direct measurement of emissions (which results in a higher cost burden to affected facilities) except for the most significant emissions sources where other options are not available, and to use engineering estimates, emissions modeling software, and leak detection and publicly available emission factors for most vented and fugitive sources. For smaller fugitive and inaccessible to plain view (*i.e.* buried or below grade in vaults) sources, component count and population emissions factors are proposed. In the case of Offshore platforms, EPA is recommending that emissions identified under the Minerals Management Services (MMS) GOADS (Gulfwide Offshore Activities Data System) be used for reporting, and the GOADS process be extended to platforms in other Federal regions (*i.e.,* California and Alaska) and all State waters. These alternative methodologies will provide similar or better coverage of vented and fugitive methane and carbon dioxide emissions in the petroleum and gas industry, while significantly reducing industry burden.

As described in the next section, EPA collected and evaluated cost data from multiple sources, and weighed the analysis prepared at initial proposal against the input received through public comments. In any analysis of this type, there will be variations in costs among facilities, and after thoroughly reviewing the available information, we have concluded that the costs developed for this supplemental proposed rule in each petroleum and gas industry segment appropriately reflects a "representative facility" in those segments.

2. Summary of Method Used To Estimate Compliance Costs

EPA estimated costs of complying with the rule for reporting fugitive and vented GHG emissions in each affected petroleum and gas industry facility, as well as emissions from stationary combustion sources at petroleum and gas industry facilities (for threshold and burden analysis only; stationary combustion is reported under Subpart C). This supplemental rulemaking proposes methodologies for reporting fugitive and vented emissions from oil and gas facilities. Once triggering the proposed rule, all of these facilities would also have to report emissions from stationary combustion. The costs of compliance for this proposed rule includes the costs associated with calculating and reporting fugitive and vented emissions, as well as the costs of any incremental combustion-related emissions that would be required to be reported by facilities (*i.e.,* combustion emissions that were not already required to be reported under the final MRR). The representative year of the analysis is 2006 and all annual costs were estimated using the 2006 population of emitting sources. EPA used available industry and EPA data to characterize conditions at affected sources. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility and the associated costs were estimated.

The costs of complying with the rule will vary from one petroleum and gas industry segment and facility to another, depending on the types of emissions, the number of affected sources at the facility, existing monitoring, recordkeeping, and reporting activities at the facility, etc. The costs include labor costs for developing a plan, setting up records, collecting field data, performing monitoring, inputting field data into engineering models, recordkeeping, and reporting activities necessary to comply with the rule. For some facilities, costs include expenditures related to monitoring, recording, and reporting both process emissions of GHGs and emissions from stationary combustion. For other facilities (*e.g.,* LDCs), the only emissions of GHGs are process emissions. EPA's estimated costs of compliance are discussed in greater detail below:

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

• Developing a plan: reporting entity management and technical staff hours to applicability to the rule, organize indoctrination of rule requirements, identify staffing assignments, train staff, 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 standardized models

• 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.

• Record keeping: 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 reporting it to EPA through electronic systems.

Staff activities and associated labor costs will vary from facility to facility and potentially vary over time where first year start-up costs are more significant and where site-specific emissions factors are developed every two or three years. Thus, cost estimates are developed for start-up and first-time reporting, and subsequent reporting. Wage rates to monetize staff time are obtained from the Bureau of Labor Statistics (BLS).

Equipment Costs. Equipment costs include both the initial purchase price of monitoring equipment and any facility/process modification that may be required for installation and/or use of monitoring equipment. 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 costs analyses annualized capital equipment costs with appropriate lifetime and interest rate assumptions. Cost recovery periods and interest rates vary by industry, but typically, one-time capital costs are amortized over a 10-year cost recovery period at a rate of seven percent.

B. What are the costs of the proposed rule?

1. Summary of Costs

For the cost analysis, EPA gathered existing data from EPA studies and publications, industry trade associations and publicly available data sources (*e.g.,* labor rates from the BLS) to characterize the processes, sources, sectors, facilities, and companies/entities affected. EPA also considered cost data submitted in public comments on the proposed rule. Costs were estimated on a per entity basis and then weighted by the number of entities affected at the 25,000 metric tons CO_2e threshold.

To develop the costs for the rule, EPA estimated the number of affected facilities in each source category, the number and types of 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 the measurements that are already being made for reasons not associated with the rule (to allow only the incremental costs to be estimated). Many of the affected source categories, especially those that are the largest emitters of GHGs (*e.g.,* glycol dehydrators, petroleum stock tanks, gas processing plants) are subject to national emission standards and we use data generated in the development of these standards to estimate the number of sources affected by the proposed reporting rule.

Other components of the cost analysis included estimates of labor hours to perform specific activities, cost of labor, and cost of monitoring equipment. Estimates of labor hours were based on previous analyses of the costs of monitoring, reporting, and recordkeeping for other rules; information from the industry characterization on the number of units or process inputs and outputs to be monitored; and engineering judgment by industry and EPA industry experts and engineers. Labor costs were taken from the BLS and adjusted to account for overhead. Monitoring costs were generally based on cost algorithms or approaches that had been previously developed, reviewed, accepted as adequate, and used specifically to estimate the costs associated with various types of measurements and monitoring.

A detailed engineering analysis was conducted for each petroleum and gas industry segment of this proposed rule to develop unique unit costs. This analysis is documented in the Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions under Subpart W Supplemental Rule (EPA–HQ–OAR–2009–0923). 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. Incremental combustion-related emissions that would be required to be reported by facilities (as noted above) were estimated using Tier 1 factors from Subpart C of the Final MRR. Section 4 of the Economic Impact Analysis for the proposed rule contains a description of the engineering cost analysis.

Table W–7 of this preamble presents: the emissions covered under this proposed supplemental rule, the first year total costs and the first year cost per ton for process and combustion emissions, and these values for the subsequent years. EPA estimates that the total cost for process emissions in the first year is $56.0 million, and the total national annualized cost for subsequent years is $21.4 million (2006$). Of these costs, roughly 49.5 percent fall upon the onshore production segment in the first year, while 34.5 percent fall upon the gas transmission segment. Offshore production, which is largely covered by the MMS GOADS study data, is estimated to incur approximately 0.5 percent of costs every three or four years; other segments incurring relatively large shares of costs are gas processing (12.5 percent) and local distribution companies (3 percent). The reporting of incremental combustion related emission for all segments of the petroleum and natural gas industry are estimated to cost $3.9 million in both the first and subsequent years.

The threshold, in large part, determines the number of entities required to report GHG emissions and hence the costs of the rule. The number of entities excluded increases with higher thresholds. Table W–8 of this preamble provides the cost-effectiveness analysis for various thresholds examined. Two metrics are used to evaluate the cost-effectiveness of the emissions threshold. The first is the average cost per metric ton of emissions reported ($/metric ton CO_2e). The second metric for evaluating the threshold option is the incremental cost of reporting emissions. The incremental cost is calculated as the additional (incremental) cost per metric ton starting with the least stringent option and moving successively from one threshold option to the next. For more information about the first year capital costs (unamortized), project lifetime and the amortized (annualized) costs for each petroleum and gas industry segment please refer to section 4 of the Economic Analysis for the proposed rule. Not all segments require capital expenditures but those that do are clearly documented in the Economic Impact Analysis for the proposed rule.

TABLE W–7—NATIONAL COST ESTIMATES FOR PETROLEUM AND NATURAL GAS SYSTEMS

[2006$]

Subpart W—petroleum and natural gas systems	NAICS	First year			Subsequent years		
		$million[1] 2006	Million $MtCO_2e$	$/ton	$million 2006	Million $MtCO_2e$	$/ton
Fugitive and Vented Emissions	211, 486	$56	272.0	$0.21	$21.4	272.0	$0.08
Combustion Emissions		3.9	79.1	0.05	3.9	79.1	0.05
Total Private Sector Emissions		59.9	351.1	0.17	25.3	351.1	0.07

TABLE W–8—THRESHOLD COST-EFFECTIVENESS ANALYSIS

[Subsequent year, 2006$]

Threshold (metric tons CO_2e)	Facilities required to report	Total costs (million $2006)	Downstream emissions reported ($MtCO_2e$/year)	Percentage of total downstream emissions reported	Average reporting cost ($/ton)	Incremental cost ($/metric ton) [1]
100,000	1,143	$13.66	273	64	$0.05	$0.05
25,000	3,037	25.30	351	83	0.08	0.13
10,000	4,884	38.62	380	90	0.10	0.23
1,000	15,057	97.18	415	98	0.23	0.46

[1] Cost per metric ton relative to the selected option.

C. What are the economic impacts of the proposed rule?

1. Summary of Economic Impacts

EPA prepared an economic impact analysis to evaluate the impacts of the rule on affected small to large reporting entities. In evaluating the various reporting options considered, EPA conducted a cost-effectiveness analysis, comparing the cost per metric ton of GHG emissions across reporting options. EPA used this information to identify the preferred options described in today's proposed rule.

To estimate the economic impacts of the 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. Overall national costs of the rule are significant because there are a large number of affected entities, but per-entity costs are low due to large coverage of emissions from these entities. 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 proposed rule is unlikely to result in significant changes in firms' production decisions or other behavioral changes, and thus unlikely to result in significant changes in prices or quantities in affected markets. Thus, EPA followed its *Guidelines for Preparing Economic Analyses* (EPA, 2002, p. 124–125) and used the engineering cost estimates to measure the social cost of the rule, rather than modeling market responses and using the resulting measures of social cost. Table W–9 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE W–9—ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES

[Year 1]

NAICS	NAICS description	Average cost per entity ($1,000/entity)	Average entity cost-to-sales ratio[1]
211	Crude Petroleum and Natural Gas Extraction	$24	0.11%
486210	Pipeline Transportation of Natural Gas	18	0.10%
221210	Natural Gas Distribution	11	0.05%

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

D. What are the impacts of the proposed rule on small 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 83 percent of U.S. GHG emissions from the industry segments reported by approximately 3,037 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 U.S., while excluding most of the smaller facilities and sources. We received many comments related to monitoring and reporting requirements in specific source categories, and made many changes in response to reduce burden on reporters. For information on these issues, refer to the discussion of each segment in this preamble.

EPA conducted a screening assessment comparing compliance costs to onshore petroleum and natural gas production 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.[9] 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 W–10 of this preamble.

TABLE W–10.—ESTIMATED COST-TO-SALES RATIOS FOR FIRST YEAR COSTS BY INDUSTRY AND ENTERPRISE SIZE[A]

Industry	NAICS	NAICS Description	SBA Size Standard (effective March 11, 2008)	Average cost per entity ($1,000/entity)	All enterprises	Owned by enterprises with:						
						<20 employees[f]	20 to 99 employees	100 to 499 employees	500 to 749 employees	<500 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 employees.	$24	0.11%	1.83%	0.16%	0.07%	0.03%	0.65%	0.04%	0.03%
Onshore natural gas processing; onshore natural gas transmission; underground natural gas storage.	486210	Pipeline Transportation of Natural Gas.	7.5 million dollars.	18	0.10	0.14	0.47[b]	0.28[b]	....	0.12	....	....
Natural gas distribution.	221210	Natural Gas Distribution.	7.5 million dollars.	11	0.05	0.22	0.02	0.05	0.09	0.06	0.02	0.02

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

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

[2] The Census Bureau has missing data ranges for this employee range. Hence the receipts are an underestimate of the true value. Therefore, the cost-to-sales ratio is a conservative estimate.

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, except the ratio for 1–20 employee range for crude petroleum and natural gas extraction, which is greater than 1 percent but less than 2 percent. The petroleum and natural gas industry has a large number of enterprises, the majority of them in the 1–20 employee range. However, a large fraction of production comes from large corporations and not those with less than 20 employee enterprises. The smaller enterprises in most cases deal with very small operations (such as a single family owning a few production wells) that are unlikely to cross even the 25,000 metric tons CO_2e threshold considered for the rule. An exception to such a scenario is a small (less than 20 employee) enterprise owning large operations but conducting nearly all of its operations through contractors. This is not an uncommon practice in the onshore petroleum and natural gas production segment. Such enterprises, however, are a very small group among the over 19,000 enterprises in the less than 20 employee category and EPA proposes to cover them in the rule.

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.

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

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

stakeholders. When developing the rule, the Agency took special steps to ensure that the burdens imposed on small entities were minimal. The Agency conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. The Agency investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. The Agency also recommended a hybrid method for reporting, which provides flexibility to entities and helps minimize reporting costs.

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

EPA examined the potential benefits of the proposed GHG reporting rule for petroleum and natural gas systems. The benefits of a reporting system are based on their relevance to policy making, transparency issues, and market efficiency. Benefits are very difficult to quantify and monetize. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

A mandatory reporting system for petroleum and natural gas systems will benefit the public by increased transparency of facility emissions data. Transparent, public data on emissions allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers.

The greatest benefit of mandatory reporting of petroleum and natural gas systems GHG emissions to government will be realized in developing future GHG policies. For example, in the European Union's Emissions Trading System, a lack of accurate monitoring at the facility level before establishing CO_2 allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

As the primary constituent of natural gas, methane is also an important energy source. As a result, methane emissions reductions can provide significant economic and environmental benefits. EPA has been working in collaboration with oil and natural companies in the U.S. as part of the Natural Gas STAR Program since 1993. Through this collaborative partnership program, EPA has identified over 120 proven, cost effective technologies and practices to reduce methane emissions across operations in all of the major industry sectors—production, gathering and processing, transmission, and distribution. The proposed reporting rule will increase knowledge of the location and magnitude of significant methane emissions sources in the oil and gas industry which can result in cross-cutting benefits on domestic energy supply, industrial efficiency and safety, and revenue generation.

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

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

Section VI of the RIA for the Final MRR summarizes the anticipated benefits of the finalized rule, which include providing the government with sound data on which to base future policies and providing industry and the public independently verified information documenting firms' environmental performance. While EPA has not quantified the benefits of the mandatory reporting rule, EPA believes that they are substantial and outweigh the estimated costs.

IV. Statutory and Executive Order Reviews

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 proposed 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 2376.01.

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 proposed 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 proposed 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.[10]

The projected cost and hour burden for non-federal respondents is $37.8 million and 478,774 hours per year. The

[10] Although CBI determinations are usually made on a case-by-case basis, EPA has issued guidance in an earlier **Federal Register** notice on what constitutes emissions data that cannot be considered CBI (956 FR 7042–7043, February 21, 1991). As discussed in Section II.R of the Final MRR preamble, EPA is initiating a separate notice and comment process to make CBI determinations for the data collected under this rulemaking. EPA intends to issue this notice in early 2010, and will include in the notice the data proposed for collection in this rulemaking.

estimated average burden per response is 98.2 hours; the frequency of response is annual for all respondents that must comply with the proposed rule's reporting requirements; and the estimated average number of likely respondents per year is 3,038. 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 $5.3 million), a total operation and maintenance component (averaging $1.6 million per year), and a labor cost component (averaging $30.9 million per year).[11] Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number (EPA–HQ–OAR–2009–0923). Submit any comments related to the ICR to EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after April 12, 2010, a comment to OMB is best assured of having its full effect if OMB receives it by May 12, 2010. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act (RFA)

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

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

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this proposed rule include small businesses in the petroleum and natural gas industry, small governmental jurisdictions and small non-profits. We have determined that some small businesses will be affected because their production processes emit GHGs that must be reported.

The small entities directly regulated by this proposed rule include small businesses in the petroleum and gas industry, small governmental jurisdictions and small non-profits. We have determined that some small businesses will be affected because their production processes emit GHGs that must be reported.

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

As shown in Table W–10, 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. Although the costs to receipts for entities with 1–20 employees is over 1 percent, these facilities would likely not exceed the proposed 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. Further, these sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises within several employment categories. The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales-test will overstate the cost-to-receipt ratio for establishments owned by small businesses, because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

The screening analysis thus indicates that the proposed rule will not have a significant economic impact on a substantial number of small entities. The screening assessment for small governments for the Final MRR compared the sum of average costs of compliance for combustion, local distribution companies, and landfills to average revenues for small governments. Even for a small government owning all three source types, the costs constitute less than 1 percent of average revenues for the smallest category of governments (those with fewer than 10,000 people).

Although this proposed rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless took several steps to reduce the impact of this proposed rule on small entities. For example, EPA determined appropriate thresholds that reduce the number of small businesses reporting. In addition, EPA is proposing different monitoring methods for different emissions sources, requiring direct measurement only for selected sources. Also, EPA is proposing 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 Web site, along with a general fact sheet for the rule, information sheets for every source category, and an FAQ document. EPA also operated a hotline

[11] 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.

to answer questions about the proposed rule. We 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 proposed 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 proposed rule.

We have therefore concluded that today's proposed rule will not have a significant economic impact on a substantial number of small entities. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

The UMRA seeks to protect State, local, and Tribal governments from the imposition of unfunded Federal mandates. In addition, the Act seeks to strengthen the partnership between the Federal government and State, local, and Tribal governments and ensure that the Federal government covers the costs incurred during compliance with Federal mandates.

Title II of the UMRA of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private segment. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with Federal mandates that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private segment, of $100 million or more in any one year.

Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the Subpart W 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 segment in any one year. Expenditures associated with compliance, defined as the incremental costs beyond the existing regulations will not surpass $100 million in the aggregate in any year. Thus, today's rule is not subject to the requirements of sections 202 and 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. This regulation applies to facilities that directly emit greenhouse gases. It does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry that directly emits greenhouse gases above threshold levels. In addition, this proposed rule does not impose any implementation responsibilities on State, local, or Tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the proposed rule is expected to be minimal.

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 Executive Order 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, Executive Order 13132 does not apply to this action.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

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. This regulation would apply directly to petroleum and natural gas facilities that emit greenhouses gases. Although few facilities that would be subject to the rule are likely to be owned by tribal governments, EPA has sought opportunities to provide information to tribal governments and representatives during rule development. EPA consulted with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. EPA sought opportunities to provide information to Tribal governments and representatives during development of the mandatory GHG reporting rule that was proposed in April 2009 and finalized in September 2009. Today's action is a supplemental proposal to that rule. In consultation with EPA's American Indian Environment Office, EPA's outreach plan included tribes. EPA conducted several conference calls with Tribal organizations during the proposal phase. For example, EPA staff provided information to tribes through conference calls with multiple Indian working groups and organizations at EPA that interact with tribes and through individual calls with two Tribal board members of TCR. In addition, EPA prepared a short article on the GHG reporting rule that appeared on the front page 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 mandatory reporting rule, at the National Tribal Conference on Environmental Management on June 24–26, 2008. In addition, EPA had copies of a short information sheet distributed at a meeting of the National Tribal Caucus. See the "Summary of EPA Outreach Activities for Developing the GHG reporting rule," in Docket No. EPA–HQ–OAR–2008–0508–055 for a complete list of Tribal contacts. EPA participated in a conference call with Tribal air coordinators in April 2009 and prepared a guidance sheet for Tribal governments on the proposed rule. It was posted on the MRR Web site and published in the Tribal Air Newsletter.

EPA specifically solicits additional comment on this proposed rule from Tribal officials.

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

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

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

This proposed rule is not a "significant energy action" as defined in EO 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that this proposed rule is not likely to have any adverse energy effects. This proposed 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, we conclude that this proposed 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 proposed rule. Instead, from existing rules for source categories and voluntary greenhouse gas programs, EPA identified existing means of monitoring, reporting, and keeping records of greenhouse gas emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products.

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

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

Executive Order (EO) 12898 (59 FR 7629 (Feb. 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 proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

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: March 22, 2010.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend 40 CFR part 98 as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

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

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

2. Section 98.2 is amended by revising paragraph (a) introductory text 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.

* * * * *

Acid Gas means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

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 stack 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.

* * * * *

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (*i.e.,* high non-combustible component content).

* * * * *

Blowdown vent stack emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to 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 a 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 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 from escaping to the atmosphere.

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

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. 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.

* * * * *

Coal Bed Methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

* * * * *

Component, for the purposes of subpart W only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

* * * * *

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

* * * * *

Conventional wells mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

* * * * *

Dehydrator means a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

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

* * * * *

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. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

* * * * *

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996–1999 by The American Petroleum Institute and The Gas Research Institute.

* * * * *

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 rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

* * * * *

Field means standardized field names and codes of all oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List.

* * * * *

Flare combustion means unburned hydrocarbons including CH_4, CO_2, N_2O emissions resulting from the incomplete combustion of gas in flares.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

* * * * *

Fugitive emissions means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

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

* * * * *

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

* * * * *

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 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 which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

* * * * *

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 boiloff 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.

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 which is regulated by the process condition flows to a valve actuator controller where it vents (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.

* * * * *

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.

* * * * *

Onshore petroleum and natural gas production owner or operator means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates an onshore petroleum and/or natural gas production facility (as described in § 98.230(b)(2). Where more than one entity are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility.

* * * * *

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

* * * * *

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. § 1301, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

* * * * *

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.

* * * * *

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

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

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

* * * * *

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases. A reservoir is characterized by a single natural pressure system.

* * * * *

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

* * * * *

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

* * * * *

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.

* * * * *

Transmission pipeline means high pressure cross country pipeline transporting sellable 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.

* * * * *

Unconventional wells means gas well in producing fields that employ hydraulic fracturing to enhance gas production volumes.

* * * * *

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.

* * * * *

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 but not limited to 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).

* * * * *

Well completions means a 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. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

Well workover means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/ or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

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

4. Section 98.7 is amended by adding paragraphs (k), (l), and (m) to read as follows:

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

* * * * *

(k) The following material is available for purchase from the Gas Technology Institute, 1700 South Mount Prospect Road, Des Plaines, Illinois 60018, *http://www.gastechnology.org.*

(1) GRI–GLYCalc Version 4.0, IBR approved for § 98.233(e).

(2) [Reserved]

(l) The following material is available for purchase from IHS Standards Store, Jane's Information Group, Inc., 110 North Royal Street, Suite 200, Alexandria, Virginia 22314, *http://www.ihs.com.*

(1) E&P Tank Version 2.0, IBR approved for § 98.233(j) and § 98.236(c).

(2) [Reserved]

(m) The following material is available for purchase from the American Association of Petroleum Geologists, 1444 South Boulder Avenue, Tulsa, Oklahoma 74119, *www.aapg.org.*

(1) AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Volume 75, Number 10 (October 1991), pages 1644–1651, IBR approved for § 98.230(b).

(2) [Reserved]

5. Add subpart W to read as follows:

Subpart W—Petroleum and Natural Gas Systems

Subpart W—Petroleum and Natural Gas Systems

§ 98.230 Definition of the source category.

(a) This source category consists of the following:

(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 transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to 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 also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all 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 plants.* Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through 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 for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any fixed 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 includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including but not limited to, depleted gas or oil reservoirs and salt dome caverns utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including, but not limited to, compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.

(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 distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations, that physically deliver natural gas to end users.

(b) [Reserved]

§ 98.231 Reporting threshold.

(a) You must report GHG emissions from petroleum and natural gas systems if your facility as defined in § 98.230 meets the requirements of § 98.2(a)(2).

(b) For applying the threshold defined in § 98.2(a)(2), you must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead for more than 30 days in a reporting year, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

§ 98.232 GHGs to report.

(a) You must report CO_2 and CH_4 emissions from each industry segment specified in paragraph (b) through (i) of this section.

(b) For offshore petroleum and natural gas production, report emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007–067).

(c) For onshore petroleum and natural gas production, report emissions from the following source types:

(1) Natural gas pneumatic high bleed device venting.

(2) Natural gas pneumatic low bleed device venting.

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during conventional well completions.

(6) Gas well venting during unconventional well completions.

(7) Gas well venting during conventional well workovers.

(8) Gas well venting during unconventional well workovers.

(9) Gathering pipeline fugitives.

(10) Storage tanks.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring.

(14) Dehydrator vent stacks.

(15) Coal bed methane produced water emissions.

(16) EOR injection pump blowdown.

(17) Acid gas removal vent stack.

(18) Hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor wet seal degassing venting.

(20) Produced water dissolved CO_2.

(21) Fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vents, pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services).

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

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.

(3) Storage tanks.

(4) Blowdown vent stacks.

(5) Dehydrator vent stacks.

(6) Acid gas removal vent stack.

(7) Flare stacks.

(8) Gathering pipeline fugitives.

(9) Fugitive emissions from: valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.

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

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic high bleed device venting.

(6) Natural gas pneumatic low bleed device venting.

(7) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

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

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.

(3) Natural gas pneumatic high bleed device venting.

(4) Natural gas pneumatic low bleed device venting.

(5) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

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

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.

(3) Fugitive emissions from valves; pump seals; connectors; vapor recovery compressors, and other fugitive sources.

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

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.

(3) Blowdown vent stacks.

(4) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

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

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(2) Below ground meter regulators and vault fugitives.

(3) Pipeline main fugitives.

(4) Service line fugitives.

(j) You must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) You must 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.

(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.

(a) *Natural gas pneumatic high bleed device venting.* Calculate emissions from a natural gas pneumatic high bleed flow control device venting as follows:

(1) Calculate vented emissions using manufacturer data.

(i) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(ii) Calculate the natural gas emissions for each continuous bleed device using Equation W–1 of this section.

$$E_{s,n} = B_s * T \qquad \text{(Eq. W-1)}$$

Where:

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

B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic device has been operational through the reporting period.

(iii) 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.

(2) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions.

(b) *Natural gas pneumatic low bleed device venting.* Calculate emissions from natural gas pneumatic low continuous bleed device venting using Equation W–2 of this section.

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

Where:

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

Count = Total number of natural gas pneumatic low bleed devices.

EF = Population emission factors for natural gas pneumatic low bleed device venting listed in Tables W–1, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission, 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), GHGi equals 1.

Convi = Conversion from standard cubic feet to metric tons CO_2e; 0.000404 for CH_4, and 0.00005189 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(c) *Natural gas driven pneumatic pump venting.* Calculate emissions from natural gas driven pneumatic pump venting as follows:

(1) Calculate emissions using manufacturer data.

(i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer "gas consumption") per unit volume of liquid circulation rate at pump speeds and operating pressures.

(ii) Maintain a log of the amount of liquid pumped annually from individual pumps.

(iii) Calculate the natural gas emissions for each pump using Equation W–3 of this section.

$$E_{s,n} = F_s * V \qquad \text{(Eq. W-3)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet per year.

F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" in scf/gallon at standard conditions, as provided by the manufacturer.

V = Volume of liquid pumped annually in gallons/year.

(iv) 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.

(2) If manufacturer data for a specific pump in Equation W–3 is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(d) *Acid gas removal (AGR) vent stacks.* For AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) using Equation W–4 of this section.

$$E_{a,CO2} = \left(V_1 * \%Vol_1\right) - \left(V_2 * \%Vol_2\right) \qquad \text{(Eq. W-4)}$$

Where:

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

V_1 = Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition.

$\%Vol_1$ = Volume weighted CO_2 content of natural gas into the AGR unit.

V_2 = Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition.

$\%Vol_2$ = Volume weighted CO_2 content of natural gas out of the AGR unit.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, quarterly gas samples must be taken to determine $\%Vol_1$ and $\%Vol_2$ according to methods set forth in § 98.234(b).

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

(3) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraphs (u) and (v) of this section.

(e) *Dehydrator vent stacks.* For dehydrator vent stacks without vapor recovery or thermal control devices, calculate annual mass CH_4 and CO_2 emissions at standard temperature and pressure (STP) conditions using the simulation software package GRI–GLYCalc Version 4.0 (incorporated by reference, see § 98.7).

(1) A minimum of the following parameters must be used for characterizing 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, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature, pressure, and composition.

(2) Calculate annual emissions from dehydrator vent stacks to flares or regenerator fire-box/fire tubes as follows:

(i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (e)(1) of this section.

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

(3) 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–5 of this section.

$$E_{s,n} = \frac{\left(H * D^2 * P * P_2 * \%G * 365\text{days/yr}\right)}{\left(4 * P_1 * T * 1,000\text{cf/Mcf}\right)} \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions.
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).

(i) 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.*

(1) The emissions for well venting for liquids unloading shall be determined using either of the calculation methodologies described in paragraph (f)(1) of this section. The same calculation methodology must be used for the entire volume for the reporting year.

(i) *Calculation Methodology 1.* For each unique well tubing diameter and producing horizon/formation combination in each gas producing 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–6 of this section.

$$E_{a,n} = T * FR \qquad \text{(Eq. W-6)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at ambient conditions in cubic feet.
T = Cumulative amount of time in hours of well venting during the year.
FR = Flow Rate in cubic feet per hour, under ambient conditions as required in paragraph (f)(1)(i)(A), (f)(1)(i)(B) and (f)(1)(i)(C) of this section.

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

(A) The average flow rate per minute of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field.

(B) This factor is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting from all wells of the same tubing diameter and producing horizon/formation combination in that field.

(C) A new emission factor is calculated every other year for each reporting field and horizon.

(ii) *Calculation Methodology 2.* Calculate emissions from each well venting for liquids unloading using Equation W–7 of this section.

$$E_{s,n} = \left\{\left(0.37\times10^{-3}\right) * CD^2 * WD * SP * V\right\} + \{SFR * HR\} \qquad \text{(Eq. W-7)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
0.37×10^{-3} = {pi(3.14)/4}/{(14.7*144) psia converted to pounds per square feet}
CD = Casing diameter (inches).
WD = Well depth (feet).
SP = Shut-in pressure (psig).
V = Number of vents per year.
SFR = Sales flow rate of gas well in cubic feet per hour.
HR = Hours that the well was left open to the atmosphere during unloading.

(A) 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.

(B) [Reserved]

(g) *Gas well venting during unconventional well completions and workovers.* Calculate emissions from gas unconventional well venting during well completions and workovers from hydraulic fracturing using Equation W–8 of this section. Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section. 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.

$$E_{a,n} = T * FR \qquad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$ = Annual natural gas vented emissions at ambient conditions in cubic feet.
T = Cumulative amount of time in hours of well venting during the year.
FR = Flow Rate in cubic feet per hour, under ambient conditions, as required in paragraph (g)(1) of this section.

(1) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1). The same calculation methodology must be used for the entire volume for the reporting year.

(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 shall be installed on the vent line during each well unloading event according to methods set forth in § 98.234(b).

(A) The average flow rate in cubic feet per minute of venting is calculated for one well completion in each field and for one well workover in each field.

(B) The respective flow rates are applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers, respectively, in that field.

(C) New flow rates for completions and workovers are calculated every other year for each reporting field and horizon.

(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 pressures measured before and after the well choke according to methods set forth in § 98.234(b).

(A) The average flow rate in cubic feet per minute of venting across the choke is calculated for one well completion in each field and for one well workover in each field.

(B) The respective flow rates are applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers in that field.

(C) New flow rates for completions and workovers are calculated every other year for each reporting field and horizon.

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

(iv) 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.

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

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (g)(1) 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 from the flare.

(h) *Gas well venting during conventional well completions and workovers.* Calculate emissions from each gas well venting during conventional well completions and workovers using Equation W–9 of this section:

$$E_{a,n} = V * T \qquad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$ = Annual emissions in cubic feet at ambient conditions from gas well venting during conventional well completions or workovers.

V = Daily gas production rate in cubic feet per minute.

T = Cumulative amount of time of well venting in minutes during the year.

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

(ii) 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.

(iii) *Blowdown vent stacks.* Calculate blowdown vent stack emissions as follows:

(1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns for each equipment type.

(3) Calculate the total annual venting emissions using Equation W–10 of this section:

$$E_{a,n} = N * V_v \qquad \text{(Eq. W-10)}$$

Where:

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

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves in cubic feet.

(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.

(j) *Onshore production and processing storage tanks.* For emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter) and onshore natural gas processing facilities, calculate annual CH_4 and CO_2 emissions using the latest software package for E&P Tank (incorporated by reference, see § 98.7).

(1) A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

(i) Separator oil composition.

(ii) Separator temperature.

(iii) Separator pressure.

(iv) Sales oil API gravity.

(v) Sales oil production rate.

(vi) Sales oil Reid vapor pressure.

(vii) Ambient air temperature.

(viii) Ambient air pressure.

(2) Determine if the storage tank has vapor recovery or thermal control devices.

(i) Adjust the emissions estimated using E&P Tank (incorporated by reference, see § 98.7) downward by the magnitude of emissions captured using a vapor recovery system for beneficial use.

(ii) [Reserved]

(3) Calculate emissions from liquids sent to atmospheric storage tanks vented to flares as follows:

(i) Use the storage tank emissions 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 storage tank emissions from the flare.

(4) If liquids are sent to atmospheric storage tanks where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank (incorporate by reference, see § 98.7), then emissions shall be calculated as follows:

(i) Use the storage tank emissions as determined in this section.

(ii) Multiply the emissions by 3.87 for sales oil less than 45 API gravity.

(iii) Multiply the emissions by 5.37 for sales oil equal to or greater than 45 API gravity.

(k) *Transmission storage tanks.* For storage tanks without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate annual emissions as follows:

(1) Monitor tank vapor vent stack for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) for a duration of 5 minutes.

(2) If the tank vapors are continuous then use a meter to measure tank vapors.

(i) Use a meter, such as, but not limited to a turbine meter, to estimate tank vapor volumes according to methods set forth in § 98.234(b).

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

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

(i) Use the storage tank emissions volume and gas composition as determined in paragraph (j)(1) 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 well testing venting and flaring emissions as follows:

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

(i) If GOR is not available then use an appropriate standard method published by a consensus-based standards organization to determine GOR.

(ii) [Reserved]

(2) Estimate venting emissions using Equation W–11 of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. W-11)}$$

Where:

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

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

(4) 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.

(5) 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 associated gas venting and flaring emissions as follows:

(1) Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared.

(i) If GOR is not available then use an appropriate standard method published by a consensus-based standards organization to determine GOR.

(i) [Reserved]

(2) Estimate venting emissions using the Equation W–12 of this section.

$$E_{a,n} = GOR * V \qquad \text{(Eq. W-12)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under ambient 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 = Total volume of oil produced in barrels in the reporting year.

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

(4) 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.

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

(i) Use the associated natural gas volume and gas composition as determined in paragraphs (m)(1) through (3) 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 stacks.* Calculate 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 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, company records, or similar estimates of volumetric flare gas flow.

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

(ii) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then use a representative composition from the source for the stream.

(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–13, W–14, and W–15 of this section.

$$E_{a,i}(un\text{-}combusted) = V_a * (1-\eta) * X_i \qquad \text{(Eq. W-13)}$$

$$E_{a,CO_2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \qquad \text{(Eq. W-14)}$$

$$E_{a,i}(total) = E_{a,i}(combusted) + E_{a,i}(un\text{-}combusted) \qquad \text{(Eq. W-15)}$$

Where:

$E_{a,i}$ (un-combusted) = Contribution of annual uncombusted GHG i emissions from flare stack in cubic feet, under ambient conditions.

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

$E_{a,I}$ (total) = Total annual emissions from flare stack in cubic feet, under ambient conditions.

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

η = Percent of natural gas combusted by flare (default is 98 percent).

X_i = Concentration of GHG i in gas to the flare.

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

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

(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 N_2O emissions using the emission factors for Gas Flares listed in Table W–8 of this subpart.

(8) This emissions source excludes any emissions calculated under other emissions sources in § 98.233.

(o) *Centrifugal compressor wet seal degassing vents.* Calculate emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor determine the volume of vapors from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in § 98.234(b).

(2) Estimate annual emissions using meter flow measurement using Equation W–16 of this section.

$$E_{a,i} = MT * T * M_i * (1 - B) \qquad \text{(Eq. W-16)}$$

Where:

$E_{a,i}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter reading of gas emissions per unit time.

T = Total time the compressor associated with the wet seal(s) is operational in the reporting year.

M_i = Mole percent of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B = Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (t) of this section.

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

(5) Calculate emissions from degassing vent vapors to flares as follows:

(i) Use the degassing vent vapor volume and gas composition as determined in paragraphs (o)(1) through (3) 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 rod packing venting.* Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows:

(1) Estimate annual emissions using a meter flow measurement using Equation W–17 of this section.

$$E_{a,i} = MT * T * M_i \qquad \text{(Eq. W-17)}$$

$E_{a,i}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter volumetric reading of gas emissions per unit time, under ambient conditions.

T = Total time the compressor associated with the venting is operational in the reporting year.

M_i = Mole percent of GHG i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then 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 valves using bagging according to methods set forth in § 98.234(c).

(ii) Use a temporary meter such as, but not limited to, a vane anemometer or a permanent meter such as, but not limited to, an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in § 98.234(b).

(3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:

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

(ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in § 98.234(d).

(4) Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period:

(i) Operating.

(ii) Standby pressurized.

(iii) Not operating, depressurized.

(5) Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) 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 an annual leak detection of fugitive emissions from all sources listed in § 98.232(d)(9), (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. If fugitive emissions are detected for sources listed in this paragraph, calculate emissions using Equation W–18 of this section for each source with fugitive emissions.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-18)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source found to be leaking.

EF = 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)(3) through (a)(8), GHG_i equals 1.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(2) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for fugitive emissions detected from valves; connectors; open ended lines; pressure relief valves; meters; and centrifugal compressor dry seals.

(3) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for fugitive emissions detected from connectors; block valves; control valves; compressor blowdown valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(4) 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 fugitive emissions detected from connectors; block valves; control valves; compressor blowdown valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(5) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for fugitive emissions detected from valves; pump seals; connectors; and other.

(6) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for fugitive emissions detected from valves; pump seals; connectors; and other.

(7) Natural gas distribution facilities for above ground meter regulator and gate stations shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for fugitive emissions detected from connectors; block valves; control valves; pressure relief valves; orifice meters; other meters; regulators; and open ended lines.

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232(c)(2), (c)(9), (c)(15), (c)(21), (d)(8), (e)(6), (f)(4), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3) and (i)(4), 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. Calculate emissions from all sources listed in this paragraph using Equation W–19 of this section.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-19)}$$

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source at the facility.

EF = Population emission factor for specific sources listed in Table W–1 through Table W–7 of this subpart.

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 (b)(3) through (b)(8),GHG_i equals 1.

T = Total time the specific source associated with the fugitive emission was operational in the reporting 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–1 of this subpart for fugitive emissions from valves; connectors; open ended lines; pressure relief valves; compressor starter gas vent; pump; flanges; other; and CBM well water production. Where facilities conduct EOR operations the emissions factor listed in Table W–1 shall be used to estimate all streams of gases, including recycle CO_2 stream. In cases where the stream is almost all CO_2, the emissions factors in Table W–1 shall be assumed to be for CO_2 instead of natural gas.

(3) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table W–2 of this subpart for fugitive emissions from gathering pipelines.

(4) 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 fugitive emissions from connectors; valves; pressure relief valves; and open ended lines.

(5) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for fugitive emissions from vapor recovery compressors.

(6) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for fugitive emissions from vapor recovery compressors.

(7) Natural gas distribution facilities shall use the appropriate default population emission factors listed in Table W–7 of this subpart for fugitive emissions from below grade M&R stations; gathering pipelines; mains; and services.

(s) *Offshore petroleum and natural gas production facilities in both state and federal waters.* Report GHG emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007–067) for each platform.

(1) MMS GOADS Reporters. Offshore production facilities currently reporting under the MMS GOADS program will report the same annual emissions as calculated by GOADS under paragraph (s) of this section.

(i) For the first reporting year, report the latest available emissions from GOADS.

(ii) In subsequent reporting years when GOADS is updated reporters shall report the new emissions that are made available from the latest GOADS software.

(ii) For each reporting year that does not overlap with the GOADS reporting year, report the last reported GOADS emissions with emissions adjusted based on the operating time for each platform.

(iii) If MMS discontinues or delays their GOADS survey by more than 4 years, then Platform operators shall collect monthly activity data every 4 years from platform sources in accordance with the latest version of the MMS GOADS program instructions, beginning in the year that the GOADS survey would have been conducted, and annual emissions shall be calculated using the latest available MMS GOADS emission factors and methods.

(2) Non-MMS GOADS Reporters. Offshore production facilities not reporting under the MMS GOADS program shall collect monthly activity data from platform sources for the first reporting year in accordance with the latest MMS GOADS program instructions. Annual emissions shall be calculated using the latest MMS GOADS emission factors and methods.

(i) In subsequent reporting years, facilities not reporting under GOADS shall follow the data collection cycle as GOADS in collecting new activity data monthly to estimate emissions and report emissions.

(ii) For each reporting year that does not overlap with the GOADS reporting year, report the last reported emissions data with emissions adjusted based on the operating time for each platform.

(iii) If MMS discontinues or delays their GOADS survey by more than 4 years, then Platform operators shall collect monthly activity data every 4 years from platform sources in accordance with the latest version of the MMS GOADS program instructions, and annual emissions shall be calculated using currently available MMS GOADS emission factors and methods.

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section.

(1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure natural gas using Equation W–20 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \text{(Eq. W-20)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions.
T_s = Temperature at standard conditions. (°F).
T_a = Temperature at actual emission conditions. (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation W–21 of this section.

$$E_{s,i} = \frac{E_{a,i} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \text{(Eq. W-21)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,i}$ = GHG i volumetric emissions at actual conditions.
T_s = Temperature at standard conditions. (°F).
T_a = Temperature at actual emission conditions. (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–22 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. W-22)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.
M_i = Mole percent of GHG i in the natural gas.

(2) For Equation W–22 of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole percent 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 in calculating emissions. If you do not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in § 98.234(b).

(ii) GHG mole percent in feed natural gas for all emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(v) GHG mole percent in natural gas stored in LNG storage facilities.

(vi) GHG mole percent in natural gas stored in LNG import and export facilities.

(vii) GHG mole percent 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–23 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \qquad \text{(Eq. W-23)}$$

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, 0.053 kg/ft³ for CO_2 and 0.0193 kg/ft³ for CH_4.
GWP = Global warming potential, 1 for CO_2 and 21 for CH_4.

(w) *EOR injection pump blowdown.* Calculate pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including, but not limited to, pipelines, compressors and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per reporting period.

(3) Calculate the total annual venting emissions using Equation W–24 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \qquad \text{(Eq. W-24)}$$

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 reporting year.
V_v = Total volume in cubic feet of blowdown equipment chambers (including, but not limited to, pipelines, compressors, manifolds and vessels) between isolation valves.
R_c = Density of critical phase EOR injection gas in kg/ft³. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.
GHG_i = Mass fraction of GHG_i in critical phase injection gas.

(x) *Hydrocarbon liquids dissolved CO_2.* Calculate dissolved CO_2 in hydrocarbon liquids as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Quarterly 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 average of the quarterly analysis for the reporting period.

(2) Estimate emissions using Equation W–25 of this section.

$$Mass_{s,\,CO2} = S_{h1} * V_{h1} \qquad \text{(Eq. W-25)}$$

Where:

$Mass_{s,\,CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids 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 in barrels in the reporting year.

(y) *Produced water dissolved CO_2.* Calculate dissolved CO_2 in produced water as follows:

(1) Determine the amount of CO_2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. Use the average of the quarterly analysis for the reporting period.

(2) Estimate emissions using the Equation W–26 of this section.

$$\text{Mass, } CO2 = Spw * Vpw \qquad \text{(Eq. W-26)}$$

Where:

$Mass_{s,\,CO2}$ = Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, in metric tons.
S_{pw} = Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.
V_{pw} = Total volume of produced water produced in barrels in the reporting year.

(3) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from paragraph (y) of this section.

(z) *Portable equipment combustion emissions.* Calculate emissions from portable equipment using the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.234 Monitoring and QA/QC requirements.

(a) You must use the method described as follows to conduct annual leak detection of fugitive emissions from all source types listed in § 98.233(p)(3)(i) and (q) in operation or on standby mode that occur during a reporting period.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, § 60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks.* In addition, you must operate the optical gas imaging instrument to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters.

(2) [Reserved]

(b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as, but not limited to, ASTM International, American National Standards Institute (ANSI), and American Petroleum Institute (API). If a consensus based standard is not available, you must use manufacturer instructions to calibrate the meters, analyzers, and pressure gauges.

(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, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

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

§ 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 reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting 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.

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions as specified in this section.

(a) Report annual emissions separately for each of the industry segment listed in paragraphs (a) (1) through (8) of this section. For each segment, report emissions from each source type in the aggregate, unless specified otherwise. For example, an underground natural gas storage 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) Report emissions separately for standby equipment.

(c) Report activity data for each aggregated source type as follows:

(1) Count of natural gas pneumatic high bleed devices.

(2) Count of natural gas pneumatic low bleed devices.

(3) Count of natural gas driven pneumatic pumps.

(4) For each acid gas removal unit report the following:

(i) Total volume of natural gas flow into the acid gas removal unit.

(ii) Total volume of natural gas flow out of the acid gas removal unit.

(iii) Volume weighted CO_2 content of natural gas into the acid gas removal unit.

(5) For each dehydrator unit report the following:

(i) Glycol dehydrators:

(A) Glycol dehydrator feed natural gas flow rate.

(B) Glycol dehydrator absorbent circulation pump type.

(C) Glycol dehydrator absorbent circulation rate.

(D) Whether stripper gas is used in glycol dehydrator.

(E) Whether a flash tank separator is used in glycol dehydrator.

(ii) Desiccant dehydrators:

(A) The number of desiccant dehydrators operated.

(B) [Reserved]

(6) Count of wells vented to the atmosphere for liquids unloading for each field in the basin.

(7) Count of wells venting during well completions for each field in the basin.

(i) Number of conventional completions.

(ii) Number of completions involving hydraulic fracturing.

(8) Count of wells venting during well workovers for each field in the basin.

(i) Number of conventional well workovers involving well venting to the atmosphere.

(ii) Number of unconventional well workovers involving well venting to the atmosphere.

(9) For each compressor blowdown vent stack report the following for each compressor:

(i) Type of compressor whether reciprocating or centrifugal.

(ii) Compressor capacity in horse powers.

(iii) Volume of gas between isolation valves.

(iv) Number of blowdowns per year.

(10) For each estimate of gas emitted from liquids sent to atmospheric tank using E&P Tank report the following:

(i) Immediate upstream separator temperature and pressure.

(ii) Sales oil API gravity.

(iii) Estimate of individual tank or tank battery capacity in barrels.

(iv) Oil, hydrocarbon condensate and water sent to tank(s) in barrels.

(v) Control measure: Either vapor recovery system or flaring of tank vapors.

(11) For tank emissions identified using optical gas imaging instrument per § 98.234(a), report the following for each tank:

(i) Immediate upstream separator temperature and pressure.

(ii) Sales oil API gravity.

(iii) Tank capacity in barrels.

(iv) Tank throughput in barrels.

(v) Control measure: Either vapor recovery system or flaring of tank vapors.

(vi) Optical gas imagining instrument used.

(vii) Meter used for measuring emissions.

(viii) List of emissions sources routed to the tank.

(12) For well testing report the following for each field in the basin:

(i) Number of wells tested in reporting period.

(ii) Average gas to oil ratio for each field.

(iii) Average flow rate during testing for each field.

(iv) Average number of days the well is tested.

(v) Whether the hydrocarbons produced during testing are vented or flared.

(13) For associated natural gas venting report the following for each field in the basin:

(i) Number of wells venting or flaring associated natural gas in reporting period.

(ii) Average gas to oil ratio for each field.

(iii) Average volume of oil produced per well per field.

(iv) Whether the associated natural gas is vented or flared.

(14) For flare stacks report the following for each flare:

(i) Whether flare has a continuous flow monitor.

(ii) If using engineering estimation methods, identify sources of emissions going to the flare.

(iii) Whether flare has a continuous gas analyzer.

(iv) Identify proportion of total natural gas to pure hydrocarbon stream being sent to the flare annually for the reporting period.

(v) Flare combustion efficiency.

(15) For well venting for liquids unloading report the following by field, basin, and well tubing size:

(i) Number of wells being unloaded for liquids in reporting year.

(ii) Average number of unloading(s) per well per reporting year.

(iii) Average volume of natural gas produced per well per reporting year during liquids unloading.

(16) For well completions and workovers report the following for each field in the basin:

(i) Number of wells completed (worked over) in reporting year.

(ii) Average number of days required for completion (workover).

(iii) Average volume of natural gas produced per well per reporting year during well completion (workover).

(17) For compressor wet seal degassing vents report the following for each degassing vent:

(i) Number of wet seals connected to the degassing vent.

(ii) Number of compressors whose wet seals are connected to the degassing vent.

(iii) Total throughput of compressors whose wet seals are connected to the degassing vent.

(iv) Type of meter used for making measurements.

(v) Whether emissions estimate is based on a continuous or one time measurement.

(vi) Total time the compressor(s) associated with the degassing vent stack is operating. Sum the hours of operation if multiple compressors are connected to the vent stack.

(vii) Proportion of vent gas recovered for fuel gas or sent to a flare.

(18) For reciprocating compressor rod packing report the following per rod packing:

(i) Total throughput of the reciprocating compressor whose rod packing emissions is being reported.

(ii) Total time in hours the reciprocating compressor is in operating mode.

(iii) Whether or not the rod packing case is connected to an open ended line.

(iv) If rod packing is connected to an open ended line, report type of device used for measurement emissions.

(v) If rod packing is not connected to an open ended vent line, report the locations from where the emissions from the rod packing are detected.

(19) For fugitive emissions sources using emission factors for estimating emissions report the following:

(i) Component count for each fugitive emissions source.

(ii) CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production.

(20) For EOR injection pump blowdown report the following per pump:

(i) Pump capacity.

(ii) Volume of gas between isolation valves.

(iii) Number of blowdowns per year.

(iv) Supercritical phase EOR injection gas density.

(21) For hydrocarbon liquids dissolved CO_2 report the following for each field in the basin:

(i) Volume of crude oil produced.

(ii) [Reserved]

(22) For produced water dissolved CO_2 report the following for each field in the basin:

(i) Volume of produced water produced.

(ii) [Reserved]

(d) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether the wells are producing oil, gas, or both.

(f) Report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

(1) Aggregate emissions by source type.

(2) Report count of each source type.

§ 98.237 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected 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 below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Natural gas distribution facility means 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.

Offshore petroleum and natural gas production facility means each platform structure and all associated equipment as defined in paragraph (a)(1) of this section. All production equipment that is connected via causeways or walkways are one facility.

Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

TABLE W–1 OF SUBPART W—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Population Emission Factors—All Components, Gas Service	
Valve	0.08
Connector	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
Gathering Pipelines [1]	2.81
CBM Well Water Production [2]	0.11
Population Emission Factors—All Components, Light Crude Service [3]	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other [5]	0.24
Population Emission Factors—All Components, Heavy Crude Service [4]	
Valve	0.001
Flange	0.001
Connector (other)	0.0004
Open-ended Line	0.01
Other [5]	0.003

[1] Emission Factor is in units of “scf/hour/mile“.

[2] Emission Factor is in units of “scf methane/gallon“, in this case the operating factor is “gallons/year” and do not multiply by methane content.

[3] Hydrocarbon liquids greater than or equal to 20*API are considered "light crude".
[4] Hydrocarbon liquids less than 20*API are considered "heavy crude".
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

TABLE W–2 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING

Processing	Before de-methanizer emission factor (scf/hour/component)	After de-methanizer emission factor (scf/hour/component)
Leaker Emission Factors—Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors—Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Dry Seal	105	105
Leaker Emission Factors—Other Components, Gas Service		
Valve		6.42
Connector		5.71
Open-ended Line		11.27
Pressure Relief Valve		2.01
Meter		2.93
Population Emission Factors—Other Components, Gas Service		
Gathering Pipelines [1]		2.81

[1] Emission Factor is in units of "scf/hour/mile".

TABLE W–3 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (scf/hour/component)
Leaker Emission Factors—All Components, Gas Service	
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Population Emission Factors—Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

TABLE W–4 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE

Underground storage	Emission Factor (scf/hour/component)
Leaker Emission Factors—Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46

TABLE W–4 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE—Continued

Underground storage	Emission Factor (scf/hour/component)
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

TABLE W–5 OF SUBPART W—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	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	6.81

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

TABLE W–6 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS

LNG terminals	Emission Factor (scf/hour/component)
Leaker Emission Factors—LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	6.81

TABLE W–7 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors—Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors—Below Grade M&R Stations Components, Gas Service[1]	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.30

TABLE W–7 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR DISTRIBUTION—Continued

Distribution	Emission Factor (scf/hour/component)
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 [2]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors—Distribution Services, Gas Service [2]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Emission Factor is in units of “scf/hour/station“
[2] Emission Factor is in units of “scf/hour/service“

TABLE W–8 OF SUBPART W—DEFAULT NITROUS OXIDE EMISSION FACTORS FOR GAS FLARING

Gas Flaring	Emission Factor (metric tons/ MMscf gas production or receipts)
Population Emission Factors—Gas Flaring	
Gas Production	5.90E–07
Sweet Gas Processing	7.10E–07
Sour Gas Processing	1.50E–06
Conventional Oil Production [1]	1.00E–04
Heavy Oil Production [2]	7.30E–05

[1] Emission Factor is in units of “metric tons/barrel conventional oil production“
[2] Emission Factor is in units of “metric tons/barrel heavy oil production“

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