ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2023–0234; FRL–10246–01–OAR]

RIN 2060–AV83

Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed. The EPA is also proposing changes to requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities. This action also proposes to establish and amend confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these proposed amendments.

DATES: *Comments*. Comments must be received on or before October 2, 2023. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before August 31, 2023.

Public hearing. The EPA does not plan to conduct a public hearing unless requested. If anyone contacts us requesting a public hearing on or before August 7, 2023, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: *Comments*. You may submit comments, identified by Docket Id. No. EPA–HQ–OAR–2023–0234, by any of the following methods:

Federal eRulemaking Portal. www.regulations.gov (our preferred method). Follow the online instructions for submitting comments.

Mail: U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.–4:30 p.m., Monday-Friday (except Federal holidays).

Instructions: All submissions received must include the Docket Id. No. for this proposed rulemaking. Comments received may be posted without change to *www.regulations.gov/*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

The virtual hearing, if requested, will be held using an online meeting platform, and the EPA will provide information on its website (*www.epa.gov/ghgreporting*) regarding how to register and access the hearing. Refer to the **SUPPLEMENTARY INFORMATION** section for additional information.

FOR FURTHER INFORMATION CONTACT: Jennifer Bohman, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460; telephone number: (202) 343–9548; email address: *GHGReporting@epa.gov*. For technical information, please go to the Greenhouse Gas Reporting Program (GHGRP) website, *www.epa.gov/ghgreporting*. To submit a question, select Help Center, followed by ''Contact Us.''

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of this proposal will also be available through the WWW. Following the Administrator's signature, a copy of this proposed rule will be posted on the EPA's GHGRP website at *www.epa.gov/ghgreporting*.

SUPPLEMENTARY INFORMATION:

Written comments. Submit your comments, identified by Docket Id. No. EPA–HQ–OAR–2023–0234, at *www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *www.regulations.gov* any information you consider to be confidential business information (CBI), proprietary business information (PBI), or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). Commenters who would like the EPA to further consider in this rulemaking any relevant comments that they provided on the 2022 Proposed Rule regarding proposed revisions at issue in this proposal must resubmit those comments to the EPA during this proposal's comment period. Please visit *www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI, PBI, or multimedia submissions, and general guidance on making effective comments.

Participation in virtual public hearing. To request a virtual public hearing, please contact the person listed in the following **FOR FURTHER INFORMATION CONTACT** section by August 7, 2023. If requested, the virtual hearing will be held on August 21, 2023. The EPA will provide further information about the hearing on its website (*www.epa.gov/ghgreporting*) if a hearing is requested.

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing no later than one business day after a request has been received. To register to speak at the virtual hearing, please use the online registration form available at *www.epa.gov/ghgreporting* or contact us by email at *GHGReporting@epa.gov*. The last day to pre-register to speak at the hearing will be August 16, 2023. On August 18, 2023, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *www.epa.gov/ghgreporting*.

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *GHGReporting@epa.gov*. The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *www.epa.gov/ghgreporting*. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us by email at *GHGReporting@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of an interpreter or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by August 8, 2023. The EPA may not be able to arrange accommodations without advanced notice.

Regulated entities. This is a proposed regulation. If finalized, these proposed revisions would affect certain entities that must submit annual greenhouse gas (GHG) reports under the GHGRP (40 CFR part 98). These are proposed amendments to existing regulations. If finalized, these amended regulations would also affect owners or operators of petroleum and natural gas systems that directly emit GHGs. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	North American Industry Classification System (NAICS)	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.

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 proposed action. This table lists the types of facilities that the EPA is now aware could potentially be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you would be affected by this proposed action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A (General Provisions) and 40 CFR part 98, subpart W (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 **FOR FURTHER INFORMATION CONTACT** section.

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

AGR acid gas removal unit
AMLD Advanced Mobile Leak Detection
API American Petroleum Institute
ASTM American Society for Testing and Materials
BOEM Bureau of Ocean Energy Management
BRE Bryan Research & Engineering
Btu/scf British thermal units per standard cubic foot
CAA Clean Air Act
CBI confidential business information
CEMS continuous emissions monitoring system
CenSARA Central States Air Resources Agency
CFR Code of Federal Regulations
CH4 methane
CO2 carbon dioxide
CO2e carbon dioxide equivalent
CRR cost-to-revenue ratio
e-GGRT electronic Greenhouse Gas Reporting Tool
EG emission guidelines
EIA U.S. Energy Information Administration
EPA U.S. Environmental Protection Agency
ET Eastern time
FAQ frequently asked question
FLIGHT Facility Level Information on Greenhouse gases Tool
FR Federal Register
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas to oil ratio
gpm gallons per minute
GRI Gas Research Institute
GT gas turbines
HHV higher heating value
ICR Information Collection Request
ID identification
IRA Inflation Reduction Act of 2022
ISBN International Standard Book Number
IVT Inputs Verification Tool
kg/hr kilograms per hour
LDC local distribution company
LNG liquefied natural gas
m meters
MDEA methyl diethanolamine
MEA monoethanolamine
MMBtu/hr million British thermal units per hour
MMscf million standard cubic feet
mt metric tons
mtCO2e metric tons carbon dioxide equivalent
N2O nitrous oxide
NAICS North American Industry Classification System
NGLs natural gas liquids
NMAC New Mexico Administrative Code
NSPS new source performance standards
O&M operation and maintenance
OCS AQS Outer Continental Shelf Air Quality System
OEM original equipment manufacturer
OGI optical gas imaging
OMB Office of Management and Budget
PBI proprietary business information
ppm parts per million
ppmv parts per million by volume
PRA Paperwork Reduction Act
psig pounds per square inch gauge
REC reduced emission completion
RFA Regulatory Flexibility Act
RFI Request for Information
RICE reciprocating internal combustion engines
RY reporting year
scf standard cubic feet
scf/hr/device standard cubic feet per hour per device
THC total hydrocarbon
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
VOC volatile organic compound(s)
WWW World Wide Web

Contents

I. Background

A. How is this preamble organized?

The first section of this preamble contains background information regarding the proposed amendments. This section also discusses the EPA's legal authority under the Clean Air Act (CAA) to promulgate (including subsequent amendments to) the Greenhouse Gas Reporting Rule, codified at 40 CFR part 98 (hereafter referred to as ''part 98''), generally and 40 CFR part 98, subpart W (hereafter referred to as ''subpart W'') in particular. This section also discusses the EPA's legal authority to make confidentiality determinations for new or revised data elements required by these amendments or for existing data elements for which a confidentiality determination has not previously been proposed. Section II of this preamble describes the types of amendments included in this proposed rulemaking and includes the rationale for each type of proposed change. Section III of this preamble contains detailed information on the proposed revisions to 40 CFR part 98, subpart A (General Provisions), subpart C (General Stationary Fuel Combustion Sources) and subpart W. Section IV of this preamble discusses when the proposed revisions to part 98 would apply to reporters. Section V of this preamble discusses the proposed confidentiality determinations for new or substantially revised data reporting elements (i.e., requiring additional or different data to be reported), as well as for certain existing data elements for which a determination has not been previously established. Section VI of this preamble discusses the impacts of the proposed amendments. Section VII of this preamble describes the statutory and Executive order requirements applicable to this action.

B. Executive Summary

In August 2022, Congress passed, and President Biden signed, the Inflation Reduction Act of 2022 (IRA) into law. Section 60113 of the IRA amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' CAA section 136(c), ''Waste Emissions Charge,'' directs the Administrator to impose and collect a charge on methane (CH_4) emissions that exceed statutorily specified waste emissions thresholds from an owner or operator of an applicable facility that reports more than 25,000 metric tons carbon dioxide equivalent ($mtCO_2e$) pursuant to the Greenhouse Gas Reporting Rule's requirements for the petroleum and natural gas systems source category (codified as subpart W in EPA's Greenhouse Gas Reporting Rule regulations). Further, CAA section 136(h) requires that the EPA shall, within two years after the date of enactment of section 60113 of the IRA, revise the requirements of subpart W to ensure the reporting under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136.

In this action, the EPA is proposing revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA's authority under CAA section 114. The EPA is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W. These revisions include proposing to add a new emissions source, referred to as ''other large release events,'' to capture large emission events that are not accurately accounted for using existing methods in subpart W. Other new sources proposed to be added or included in revised existing sources include nitrogen removal units, produced water tanks, mud degassing, crankcase venting and combustion slip. The EPA is also proposing several revisions to add new or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data and to allow owners and operators of applicable facilities to submit empirical emissions data that could appropriately demonstrate the extent to which a charge is owed in future implementation of CAA section 136, as directed by CAA section 136(h). For example, the EPA is proposing new calculation methodologies for equipment leaks and natural gas pneumatic devices to allow for the use of direct measurement. The EPA is also proposing several revisions to existing reporting requirements to collect data that would improve verification of reported data, ensure accurate reporting of emissions, and improve the transparency of reported data. For example, the EPA is proposing to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, with most emissions and activity data for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting being disaggregated to at least the well-pad and site-level, respectively. The EPA is also proposing other technical amendments, corrections, and clarifications that would improve understanding of the rule. These revisions primarily include revisions of requirements to better reflect the EPA's intent or editorial changes. The proposed revisions under this rulemaking are described in further detail in sections II and III of this preamble. The EPA will be undertaking one or more separate actions in the future to implement the remainder of CAA section 136.

C. Background on This Proposed Rule

This proposed action builds on previous Greenhouse Gas reporting rulemakings. The Greenhouse Gas Reporting Rule was published in the **Federal Register** (FR) on October 30, 2009 (74 FR 56260) (hereafter referred to as the 2009 Final Rule). The 2009 Final Rule became effective on December 29, 2009, and requires reporting of GHGs from various facilities and suppliers, consistent with the 2008 Consolidated Appropriations Act.[1] Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (75 FR 16448, April 10, 2009), the final October 2009 rulemaking did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (75 FR 18608; April 12, 2010), and a subsequent final rulemaking was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as the ''2010 Final Rule''). Following promulgation, the EPA finalized several technical and clarifying amendments to subpart W (76 FR 22825, April 25, 2011; 76 FR 53057, August 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 73866, November 29, 2011; 76 FR 80554, December 23, 2011; 77 FR 48072, August 13, 2012; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014; 80 FR 64262, October 22, 2015; and 81 FR 86490, November 30, 2016). These amendments generally added or revised requirements in subpart W, including revisions that were intended to improve quality, clarity, and consistency across the calculation, monitoring, and data reporting requirements, and to finalize confidentiality and reporting determinations for data elements reported under the subpart.

More recently, the EPA proposed amendments to subpart W on June 21, 2022 (87 FR 36920) (hereafter referred to as the ''2022 Proposed Rule''), including technical amendments to improve the quality and consistency of the data collected under the rule and resolve data gaps, amendments to streamline and improve implementation, and revisions to provide additional flexibility in the calculation methods and monitoring requirements for some emission sources. The 2022 Proposed Rule was developed prior to the enactment of the IRA and its direction in CAA section 136(h) to revise subpart W. Consequently, in developing this current proposed action, the EPA considered the proposed amendments to subpart W from the 2022 Proposed Rule as well as the concerns and information submitted by commenters in response to that proposal. In this proposal, the EPA is again proposing to revise the subpart W provisions, and our proposed revisions include both (1) updates to the proposed revisions to subpart W that were in the 2022 Proposed Rule as well as (2) additional proposed revisions to comply with CAA section 136(h). The EPA accordingly does not intend to finalize the revisions to subpart W that were proposed in the 2022 Proposed Rule in the final version of that rule. Commenters who would like the EPA to further consider in this rulemaking any relevant comments that they provided on the 2022 Proposed Rule regarding its proposed revisions to subpart W must resubmit those comments to the EPA during this proposal's comment period.

Additionally, the EPA opened a non-regulatory docket on November 4, 2022, and issued a Request for Information (RFI) seeking public input to inform program design related to CAA section 136.[2] As part of this request, the EPA sought input on revisions that should be considered related to subpart W. The comment period closed on January 18, 2023.

The EPA also recently issued a supplemental proposal to the 2022 Proposed Rule (88 FR 32852, May 22, 2023), which included proposed updates to the General Provisions of the Greenhouse Gas Reporting Rule to reflect revised global warming potentials, proposed reporting of GHG data from additional sectors (*i.e.,* non-subpart W sectors), and proposed revisions to source categories other than subpart W that would improve implementation of the Greenhouse Gas Reporting Rule. These proposed revisions are being undertaken in a separate action. Accordingly, the EPA considers comments related to that action to be outside the scope of this proposed rule.

D. Legal Authority

The EPA is proposing these rule amendments under its existing CAA authority provided in CAA section 114 and under its newly established authority provided in CAA section 136, as applicable. As stated in the preamble to the 2009 Final Rule, CAA section 114(a)(1) provides the EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions. See the preambles to the proposed Greenhouse Gas Reporting Rule (74 FR 16448, April 10, 2009) and the 2009 Final Rule for further information. As noted in section I.B of this preamble, the IRA added CAA section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems,'' which requires revisions to the requirements of subpart W to ensure that reporting of CH_4emissions under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from applicable facilities, and allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. Under CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution).

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

[2] Docket ID No. EPA–HQ–OAR–2022–0875.

The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA. Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing proposed confidentiality determinations for the new or substantially revised data elements required by these proposed amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information (excluding emission data) that qualifies for confidential treatment.

E. Relationship to Other Clean Air Act Section 136 Actions

The IRA adds authorities under CAA section 136 to reduce CH_4 emissions from the oil and gas sector. It accomplishes this in multiple ways. First, it provides incentives for CH_4 mitigation and monitoring. Second, it establishes a waste emissions charge for applicable facilities that exceed statutorily-specified thresholds that vary by industry segment and are determined by the amount of natural gas or oil sent to sale. Third, CAA section 136(h) requires the EPA to revise subpart W. The first and second listed aspects of CAA section 136 are outside the scope of this rulemaking.

CAA section 136 provides $1.55 billion in incentives for CH_4 mitigation and monitoring, including through grants, rebates, contracts, loans, and other activities. Of these funds, at least $700 million is allocated to activities at marginal conventional wells. There are several potential uses of funds. Use of funds can include financial and technical assistance to owners and operators of applicable facilities to prepare and submit GHG reports under subpart W. Financial assistance can also be provided for CH_4 emissions monitoring authorized under CAA section 103 subsections (a) through (c). Additionally, financial and technical assistance can be provided to: reduce CH_4 and other GHG emissions from petroleum and natural gas systems, including to mitigate legacy air pollution from petroleum and natural gas systems; improve climate resilience of communities and petroleum and natural gas systems; improve and deploy industrial equipment and processes that reduce CH_4 and other GHG emissions and waste; support innovation in reducing CH_4 and other GHG emissions and waste from petroleum and natural gas systems; permanently shut in and plug wells on non-Federal land; and mitigate health effects of CH_4 and other GHG emissions and legacy air pollution from petroleum and natural gas systems in low-income and disadvantaged communities, and support environmental restoration.

The EPA has provided initial public engagement and input opportunities related to the design and implementation of these incentives. This has included issuing an RFI [3] to inform program design and listening sessions to enable input directly to the EPA. Through these engagement opportunities, the EPA has heard a number of common themes. First, the EPA has received input that the EPA should use funding mechanisms for rapid distribution of incentives. Second, the EPA has heard about the need for addressing critical gaps and key opportunities to achieve maximum impact. Third, the EPA has received input about the need to address cumulative pollution for overburdened communities.

The EPA is moving expeditiously to implement the incentives for CH_4 mitigation and monitoring and anticipates making announcements regarding next steps; however, as noted, those steps are outside the scope of this rulemaking.

CAA section 136(c) provides that the Administrator shall impose and collect a charge on CH_4 emissions that exceed an applicable waste emissions threshold under CAA section 136(f) from an owner or operator of an applicable facility that reports more than 25,000 $mtCO_2e$ per year pursuant to subpart W. CAA section 136 provides various flexibilities and exemptions relating to the waste emissions charge. The EPA intends to undertake one or more separate actions in the future to implement the waste emissions charge and intends to provide an opportunity for public comment in those actions; therefore, as noted, implementation of the waste emissions charge is outside the scope of this rulemaking.

As noted earlier, CAA section 136(h) requires revisions to subpart W. The purpose of this proposed action is to meet directives set forth in CAA section 136(h).

II. Overview and Rationale for Proposed Amendments to 40 CFR Part 98, Subpart W

As discussed in section I of this preamble, in August 2022, Congress passed, and President Biden signed, the IRA into law. Section 60113 of the IRA amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' CAA section 136(h) requires that the EPA shall, within two years of the enactment of that section of the IRA, revise the requirements of subpart W to ensure the reporting under that subpart and calculation of charges under CAA section 136(e) and (f) are based on empirical data, accurately reflect the total CH_4 emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed. CAA section 136(d) defines the term ''applicable facility'' as a facility within the following industry segments as defined in subpart W: offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline.

Empirical data can be defined as data that are collected by observation and experiment. There are many forms of empirical data that can be used to quantify GHG emissions. For purposes of this action, the EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (*e.g.,* leak surveys) or measurement of associated parameters (*e.g.,* flow rate, pressure, etc.), and published data. The EPA reviewed available empirical data methods for accuracy and appropriateness for calculating annual unit or facility-level GHG emissions. The review included both the evaluation of technologies and methodologies already incorporated in subpart W for measuring and reporting annual source- and facility-level GHG emissions and the evaluation of the accuracy of potential alternative technologies and methodologies, with a focus on CH_4 emissions due to the directive in CAA section 136(h).

Currently, subpart W specifies emission source types to be reported for each industry segment and provides methodologies to calculate emissions from each source type, which are then summed to generate the total subpart W emissions for the facility. Current calculation methods can be grouped

[3] Docket ID No. EPA–HQ–OAR–2022–0875.

into five categories: (1) direct emissions measurement; (2) combination of measurement and engineering calculations; (3) engineering calculations; (4) leak detection and use of a leaker emission factor; and (5) population count and population emission factors. Subpart W emission factors (both population and leaker emission factors) include both those developed from published empirical data and those developed from site-specific data collected by the reporting facility. The EPA developed the current subpart W monitoring and reporting requirements to use the most appropriate monitoring and calculation methods, considering both the accuracy of the emissions calculated by the proposed method and the size of the emission source based on the methods and data available at the time of the applicable rule promulgation. Considering the directives set forth in CAA section 136, the EPA re-evaluated the existing methodologies to determine if they are likely to accurately reflect CH_4 and waste emissions at an individual facility, whether the existing methodologies used empirical data, and whether the existing methodologies should be modified or replaced to meet CAA section 136 directives. In cases where source-level emissions were determined to be highly variable, not well characterized by an available method in subpart W, and a more accurate method, such as direct emissions measurement, is available, the EPA is proposing to update reporting requirements to reflect only methodologies that have been determined to likely accurately characterize unit or facility-level emissions. For example, intermittent bleed pneumatic devices are designed to vent during actuation only, but these devices are known to often malfunction and operate incorrectly which causes them to release gas to the atmosphere when idle, leading to high degree of variance in emissions from pneumatic devices between facilities (see *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule— Petroleum and Natural Gas Systems,* hereafter referred to as the ''subpart W TSD,'' available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234, for more information). The EPA welcomes comments on all aspects of this technical support document. Even in cases where the EPA considers an existing method that is not based on direct measurement or emission monitoring provides a reasonably accurate calculation of emissions for a facility, we also reviewed whether a direct emission measurement or emission monitoring method could be added to subpart W, if one was not already available, to give owners and operators the opportunity to submit empirical data. The EPA also evaluated whether there were gaps in the emission source types reporting CH_4 emissions under subpart W and whether there were methodologies available to calculate those emissions.

The proposed amendments include:

• Revisions to expand reporting to include new emission sources, in order to accurately reflect total CH_4 emissions reported to the GHGRP.

• Revisions to add emissions calculation methodologies to incorporate additional empirical data and improve the accuracy of reported emission data.

• Revisions to refine existing emissions calculation methodologies to reflect an improved understanding of emissions or to incorporate more recent research on GHG emissions to improve the accuracy of reported emission data.

• Revisions to remove calculation methodologies in cases where it was determined that more accurate calculation methodologies were available.

The EPA has also identified additional areas where revisions to part 98 would improve the EPA's ability to verify the accuracy of reported emissions and improve data transparency and alignment with other EPA programs and regulations. The EPA also identified areas where additional data or revised data elements may be necessary for future implementation of the waste emissions charge under CAA section 136. The proposed revisions include:

• Revisions to report emissions from facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments at the site level instead of at the basin level, sub-basin level, or county level.

• Addition of data elements related to emissions from plugged wells.

• Addition or clarification of throughput-related data elements for subpart W industry segments.

• Revisions to data elements or recordkeeping where the current requirements are redundant or alternative data would be more appropriate for verification of emission data.

• Revisions that provide additional information for reporters to better or more fully understand their compliance obligations, revisions that emphasize the EPA's intent for requirements that reporters appear to have previously misinterpreted to ensure that accurate data are being collected, and editorial corrections or harmonizing changes that would improve the public's understanding of the rule.

Sections II.A through II.D of this preamble describe the above changes in more detail and provide the EPA's rationale for the changes included in each category. Additional details for the specific amendments proposed for each subpart are included in section III of this preamble. We are seeking public comment only on the proposed revisions and issues specifically identified in this document for the identified subparts. We expect to deem any comments received addressing other aspects of 40 CFR part 98 or other rulemakings to be outside of the scope of this proposed rulemaking.

In addition, on November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR part 60, subpart OOOOb) (hereafter referred to as ''NSPS OOOOb''), as well as emissions guidelines under CAA section 111(d) for certain existing oil and natural gas sources (40 CFR part 60, subpart OOOOc) (hereafter referred to as ''EG OOOOc'') (the sources affected by these two proposed subparts are collectively referred to in this preamble as ''affected sources''). On December 6, 2022, the EPA issued a supplemental proposal to update, strengthen and expand the standards proposed on November 15, 2021 (87 FR 74702). While the standards in proposed NSPS OOOOb would directly apply to new, reconstructed, and modified sources when finalized, the final EG OOOOc would not impose binding requirements directly on sources; rather it would contain guidelines, including presumptive standards, for states to follow in developing, submitting, and implementing plans to establish standards of performance to limit GHGs (in the form of CH4 limitations) from existing oil and gas sources within their own states. If a state does not submit a plan to the EPA for approval in response to the final emission guidelines, or if the EPA disapproves a state's plan, then the EPA must establish a Federal plan. In addition, a Federal plan could apply to sources located on Tribal lands where the tribe does not request approval to develop a tribal implementation plan similar to a state plan. Once the Administrator approves a state plan under CAA section 111(d), the plan is codified in 40 CFR part 62 (Approval and Promulgation of State Plans for Designated Facilities and Pollutants) within the relevant subpart for that state.[4] 40 CFR part 62 also includes all Federal plans promulgated pursuant to CAA section 111(d). Therefore, rather than referencing the presumptive standards in EG OOOOc, which would not directly apply to sources, the proposed amendments to subpart W reference 40 CFR part 62.

Similar to the 2016 amendments to align subpart W requirements with certain requirements in 40 CFR part 60, subpart OOOOa (hereafter referred to as ''NSPS OOOOa'') (81 FR 86500, November 30, 2016), we are proposing revisions to certain requirements in subpart W relative to the requirements proposed for NSPS OOOOb and the presumptive standards proposed in EG OOOOc (which would inform the standards to be developed and codified at 40 CFR part 62). As in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs. This proposal would limit burden for subpart W facilities with affected sources that would also be required to comply with the proposed NSPS OOOOb or a State or Federal plan in part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods. Consistent with that goal, the EPA expects that the final amendments to subpart W would reference the final version of the method(s) in the NSPS OOOOb and EG OOOOc. These amendments would also improve the emission calculations reported under the GHGRP. Specifically, we are proposing amendments to the subpart W calculation methodologies for flares, centrifugal and reciprocating compressors, and equipment leak surveys related to the proposed NSPS OOOOb and presumptive standards in EG OOOOc, and we are proposing new reporting requirements for ''other large release events'' as defined in subpart W that would reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62. These proposed amendments are described in sections III.B, N, O, and P. If finalized, the provisions of these proposed amendments that reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 would not apply to individual reporters unless and until their emission sources are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. In the meantime, reporters would have the option to comply with the calculation methodologies that would be required for sources subject to NSPS OOOOb or 40 CFR part 62, or they would comply instead with the applicable provisions of subpart W that apply to sources not subject to NSPS OOOOb or 40 CFR part 62. For example, for flare sources subject to NSPS OOOOb, facilities would have the option to comply with the flare monitoring requirements in NSPS OOOOb even if the source is not yet subject to or will not be subject to those provisions. For the ''other large release events'' source category, emissions from other large release events would be required to be calculated and reported starting in Reporting Year (RY) 2025; the requirements to calculate and report these emissions is not dependent on whether a source is subject to NSPS OOOOb or 40 CFR part 62.

The specific changes that we are proposing, as described in this section, are described in detail in section III of this preamble.

A. Revisions To Address Potential Gaps in Reporting of Emissions Data for Specific Sectors

We are proposing several amendments to include reporting of additional emissions or emissions sources to address potential gaps in the total CH4 emissions reported per facility to subpart W. In particular, based on recent analyses such as those conducted for the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (U.S. GHG Inventory), and data newly available from atmospheric observations, we have become aware of potentially significant sources of emissions for which there are no current emission estimation methods or reporting requirements within part 98. For subpart W, we are proposing to add calculation methodologies and requirements to report GHG emissions for several additional sources. We are proposing to add a new emissions source, referred to as ''other large release events,'' to capture abnormal emission events that are not accurately accounted for using existing methods in subpart W. This additional source would cover events such as storage wellhead leaks, well blowouts,[5] and other large, atypical release events and would apply to all types of facilities subject to subpart W. Reporters would calculate GHG emissions using measurement data or engineering estimates of the amount of gas released and measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. We are also proposing to add calculation methodologies and requirements to report GHG emissions for several other new emission sources, including nitrogen removal units, produced water tanks, mud degassing and crankcase venting. None of these sources are currently accounted for in subpart W, and the EPA is proposing to include them because they are likely to have a meaningful impact on reported CH4 emissions. We are also proposing to revise the existing methodologies and add new measurement-based methodologies, consistent with section II.B., for determining combustion emissions from reciprocating internal combustion engines (RICE) and gas turbines (GT), including those that drive compressors, to account for combustion slip, which is not currently accounted for under the existing calculation methodologies for combustion emissions. We are also proposing to require reporting of existing emission sources by additional industry segments. For example, we are proposing to require liquefied natural gas (LNG) import/export facilities to begin calculating and reporting emissions from acid gas removal unit (AGR) vents. Additional details of these types of proposed changes may be found in section III of this preamble.

The proposed changes would ensure that the reporting under subpart W accurately reflects the total CH_4 emissions and waste emissions as required by CAA section 136(h).

B. Revisions To Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodologies

We are proposing several revisions to add new or revise existing calculation methodologies to improve the accuracy of emissions data reported to the GHGRP, incorporate additional empirical data and to allow owners and operators of applicable facilities to submit empirical emissions data that appropriately could demonstrate the extent to which a charge is owed in

[4] 40 CFR part 62 contains a subpart for each of the 50 states, District of Columbia, American Samoa, Puerto Rico, Virgin Islands, and Northern Mariana Islands.

[5] We are proposing to define a well blowout in 40 CFR 98.238 as a complete loss of well control for a long duration of time resulting in an emissions release.

future implementation of CAA section 136, as directed by CAA section 136(h). Currently, subpart W specifies emission source types to be reported for each industry segment and provides methodologies to calculate emissions from each source type, which are then summed to generate the total subpart W emissions for the facility. Considering the directives set forth in CAA section 136, the EPA re-evaluated the existing methodologies for each source to determine if they are likely to accurately reflect CH_4 and waste emissions at an individual facility, whether the existing methodologies used empirical data, *e.g.*, direct emissions measurements or monitoring of CH_4 emissions or measurement of associated parameters, and whether the existing methodologies should be modified or replaced to meet CAA section 136 directives. A summary list of the emissions sources proposed to be reported with the corresponding proposed monitoring and emissions calculation methods is available in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. Many sources in subpart W already have or require calculation methodologies that use direct emission measurement including AGR 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 via screening. Currently, subpart W has required direct measurement when the magnitude of emissions are potentially large and no credible engineering calculation methods or emission factors existed to accurately characterize emissions. In this proposal, the EPA is proposing new calculation methodologies to allow for the use of direct measurement, including for equipment leaks and natural gas pneumatic devices. The EPA is also proposing new calculation methodologies to allow for the development of site-specific emission factors for equipment leaks and pneumatic devices based on data collected from direct measurement at the facility.

We are proposing several revisions to modify calculation equations to incorporate refinements to methodologies based on an improved understanding of emission sources. In some cases, we have become aware of discrepancies between assumptions in the current emission estimation methods and the processes or activities conducted at specific facilities, where the proposed revisions would reduce reporter errors. In other cases, we are proposing to revise the emissions estimation methodologies to incorporate recent studies on GHG emissions or formation that reflect updates to scientific understanding of GHG emissions sources. The proposed changes would improve the quality and accuracy of the data collected under the GHGRP.

We are also proposing to revise several existing calculation methodologies to incorporate empirical data obtained at the facility. Emissions can be reliably calculated for sources such as tanks and glycol dehydrators using standard engineering first principle methods such as those available in API 4697 E&P Tanks [6] and GRI–GLYCalc™.[7] Using such software also addresses safety concerns that are associated with direct emissions measurement from these sources. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions. However, currently in subpart W, these methods allow for use of best available data for inputs to the model. The EPA has noted that in some cases, such as with reporting of emissions from some dehydrators, the data used to calculate emissions are not based on actual operating conditions but instead based on ''worst-case scenarios'' or other estimates. In these cases, the accuracy of the reported emissions would be improved by using actual operating conditions as measured at the unit. In this proposal, for large glycol dehydrators and AGRs, we are proposing to require that certain input parameters are based on actual measurements at the unit level in order to improve the accuracy of the reported emissions for these sources.

In order to improve the accuracy of the data collected under the GHGRP, we are proposing to revise emission factors where improved measurement data has become available or we have received additional information from stakeholders. Some of the calculation methodologies provided in the GHGRP rely on the use of emission factors that are based on published empirical data. The use of default emission factors decreases the need for additional monitoring or measurements from individual facilities, while in many cases still providing a reasonably accurate estimate of facility-level emissions. The proposed rule includes revisions to emission factors for a number of emission source types, where we have received or identified updated measurement data. In cases where there is significant variability in source-level emissions and the default emission factors are thus not appropriately representative of facility-level emissions, and other calculation methodologies are available that are representative of facility-level emissions, we are proposing to remove default emission factors. For example, for intermittent bleed pneumatics, we are proposing three new methodologies for measuring emissions and are therefore proposing to remove use of default population emission factors for calculating emissions.

We are proposing to update the emission factors for continuous low and high bleed natural gas pneumatic devices and for equipment leaks from natural gas distribution sources (including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations) and equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W. The proposed emission factors are more representative of GHG emissions sources and would improve the overall accuracy of the emission data collected under the GHGRP. Additional details of these types of proposed changes may be found in section III of this preamble.

In addition to the methods discussed above, we reviewed measurement approaches that utilize information from satellite, aerial, and continuous monitoring (''top-down approaches'') to detect and/or quantify emissions from petroleum and natural gas systems for the purposes of subpart W reporting. Top-down technologies have been a focus for research and emission monitoring strategies, and the technologies have progressed in recent years to provide reliable CH_4 emission monitoring and quantification in many cases. Top-down technologies include instruments located on satellites, aircraft, and mobile platforms. These technologies can also include Advanced Mobile Leak Detection (AMLD) and other continuous monitoring sensors. Top-down approaches have certain benefits related to geographic coverage, repeatability, and periodic measurements. Depending on the technology (satellite, aircraft, drone), the scale of observation can provide data useful for quantifying emissions in a range of cases, from quantifying emissions for a single point source, such

[6] E&P Tanks v3.0 software and the user guide (Publication 4697) formerly available from the American Petroleum Institute (API) website.

[7] GRI–GLYCalc™ software available from Gas Technology Institute website (*https://sales.gastechnology.org/*).

as a wellhead, to a basin-wide measurement. This data can be used to develop emissions estimates for the duration of the observation or can be used in combination with additional observations or other data inputs to estimate emissions from a longer time frame. Satellite remote sensing technologies currently take measurements of concentrations at altitudes of 400 to 800 kilometers with CH_4 detection limits of approximately 50 to 25,000 kilograms per hour (kg/hr),[8] with one system citing 2 parts per billion (ppb); [9] high altitude remote sensing (by airplane) measure at altitudes of 168 to 12,000 meters (m) with CH_4 detection limits of approximately 1 to 50 kg/hr; [10] and low altitude aerial remote sensing (by drone) take measurements at altitudes of 30 to 150 m with CH_4 detection ranging from approximately 5 to 250 parts per million (ppm) (depending on distance).[11] [12] For remote sensing technologies, the size of the area monitored is typically inversely related to the detection levels. Further discussion of our review of top-down technologies is available in the subpart W TSD, available in the docket for this rulemaking.

There have been several studies asserting that bottom-up CH_4 emission estimates reported by subpart W facilities underestimate annual CH_4 emissions.[13] This underestimate is often attributed to large, often episodic emissions (i.e., super-emitters).[14] Emissions estimates developed with remote sensing data may be more likely to include super-emitters, and therefore, to the extent that they capture emissions that would not have otherwise been included under prior GHGRP regulations, they can demonstrate where existing reporting data may underestimate total emissions. Some top-down approaches have a demonstrated ability to provide data useful for quantifying emissions from very large, distinct emission events, such as production well blowouts. In the U.S. GHG Inventory, the EPA has already incorporated emissions estimates developed from such approaches to calculate emissions from well blowouts.[15] In this proposal, data from such approaches could be used to identify and/or calculate emission rates of other large release events (see section III.B of this preamble).

In this proposal, the EPA is proposing to include emissions from large emissions events and super-emitters in the subpart W reporting program. This proposed addition would directly address the concerns identified by a multitude of studies about the contribution of super-emitters to total emissions and help to ensure the completeness and accuracy of emissions reporting data. The top-down monitoring approaches that have demonstrated their accuracy and ability to identify such events are a central feature of the proposed changes. This top-down data may also help to flag areas where there is a large gap between the bottom-up CH_4 emissions estimates and the top-down measurement data, requiring facilities to revise emission estimates. In this proposal, we are proposing to require facilities to consider notifications of potential super-emitter emissions event under the super-emitter provisions of NSPS OOOOb at 40 CFR 60.5371b and calculate associated events when they exceed our proposed thresholds if they are not already accounted for under another source category in subpart W. We expect that under the proposed methodology for other large release events in this proposal, data from some top-down approaches, including data derived from equipment leak and fugitive emissions monitoring using advanced screening methods which is conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62, in combination with other empirical data, could be used by reporters to calculate the total emissions from these events and/or estimate duration of such an event.

While this top-down data is very useful in identifying possible large emissions events that are not captured by other reporting obligations, it is not presently able to provide annual emissions data to the degree of accuracy and certainty required by other provisions of this rulemaking. It is not

[8] See GHGSat. *GHGSat Media Kit.* (2021). Available at *https://www.ghgsat.com/upload/misc/GHGSAT_MEDIAKIT_2021.pdf*; Pandey, S., *et al.* ''Satellite observations reveal extreme methane leakage from a natural gas well blowout.'' *Proceedings of the National Academy of Sciences*, Vol. 116, no. 52. Pp. 26376–26381, December 16, 2019, available at *https://doi.org/10.1073/pnas.1908712116*; Jacob, D. J., *et al.* ''Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane.'' *Atmospheric Chemistry and Physics*, Vol. 22, Issue 14, pp. 9617–9646, July 29, 2022, available at *https://doi.org/10.5194/acp-22-9617-2022*; Anderson, V., *et al.* ''Technological opportunities for sensing of the health effects of weather and climate change: a state-of-the-art-review.'' *International Journal of Biometeorology*, Vol. 65, Issue 6, pp. 779–803, January 11, 2021, available at *https://doi.org/10.1007/s00484-020-02063-z*. The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[9] Anderson *et al.* (2021).

[10] See Conrad, B. M., Tyner, D. R. & Johnson, M. R. ''Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies.'' *Remote Sensing of Environment*, Vol. 288, p. 113499, available at *https://doi.org/10.1016/j.rse.2023.113499*. 2023; Duren, R. M., *et al.* ''California's methane super-emitters.'' *Nature*, Vol. 575, Issue 7781, pp. 180–184, available at *https://doi.org/10.1038/s41586-019-1720-3*. 2019; Thorpe, A.K., *et al.* ''Airborne DOAS retrievals of methane, carbon dioxide, and water vapor concentrations at high spatial resolution: application to AVIRIS–NG.'' *Atmos. Meas. Tech.*, 10, 3833–3850, available at *https://doi.org/10.5194/amt-10-3833-2017*. 2017; Staebell, C., *et al.* ''Spectral calibration of the MethaneAIR instrument.'' *Atmospheric Measurement Techniques*, Vol. 14, Issue 5, pp. 3737–3753, available at *https://doi.org/10.5194/amt-14-3737-2021*. 2021. The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[11] Morales, R., *et al.* ''Controlled-release experiment to investigate uncertainties in UAV-based emission quantification for methane point sources.'' *Atmos. Meas. Tech.*, 15, 2177–2198, *https://doi.org/10.5194/amt-15-2177-2022*, 2022. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[12] Ravikumar, A. P., *et al.* ''Single-blind inter-comparison of methane detection technologies—results from the Stanford/EDF Mobile Monitoring Challenge.'' *Elementa: Science of the Anthropocene* 1 January 2019; 7 37. doi: *https://doi.org/10.1525/elementa.373*. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[13] See, *e.g.*, Caulton, *et al.* ''Toward a better understanding and quantification of methane emissions from shale gas development.'' *Proceedings of the National Academy of Sciences*, Vol. 111, Issue 17, pp. 6237–6242, available at *https://doi.org/10.1073/pnas.1316546111*. 2014; Alvarez, *et al.* ''Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey.'' *Environmental Science & Technology*, Vol. 56, Issue 7, pp. 4317–4323, available at *https://doi.org/10.1126/science.aar7204*. 2018; Zhang, *et al.* ''Quantifying methane emissions from the largest oil-producing basin in the United States from space.'' *Science Advances*, Vol. 6, Issue 17, available at *https://doi.org/10.1126/sciadv.aaz5120*. 2020. The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[14] See, *e.g.*, Zavala-Ariaza, *et al.* ''Reconciling divergent estimates of oil and gas methane emissions.'' *Proceedings of the National Academy of Sciences*, Vol. 112, Issue 51, pp. 15597–15602, available at *https://doi.org/10.1073/pnas.1522126112*. 2017; Cusworth, *et al.* ''Intermittency of Large Methane Emitters in the Permian Basin.'' *Environmental Science & Technology Letters*, Vol. 8, Issue 7, pp. 567–573, available at *https://doi.org/10.1021/acs.estlett.1c00173*. 2021; Chen, *et al.* ''Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey.'' *Environmental Science & Technology*, Vol. 56, Issue 7, pp. 4317–4323, available at *https://doi.org/10.1021/acs.est.1c06458*. 2022; Wang, *et al.* ''Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting.'' *Environmental Science & Technology*, Vol. 56, Issue 20, pp. 14743–14752, available at *https://doi.org/10.1021/acs.est.2c06211*. 2022. The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[15] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2020: Updates for Anomalous Events including Well Blowout and Well Release Emissions*. April 2022. Available at *https://www.epa.gov/system/files/documents/2022-04/2022_ghgi_update_-_blowouts.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

currently possible to use remote sensing data as the only basis to extrapolate annual emissions data. Most top-down, facility measurements are taken over limited durations (a few minutes to a few hours) typically during the daylight hours and limited to times when specific meteorological conditions exist (*e.g.,* no cloud cover for satellites; specific atmospheric stability and wind speed ranges for aerial measurements). These direct measurement data taken at a single moment in time may not be representative of the annual CH_4 emissions from the facility, given that many emissions are episodic. If emissions are found during a limited duration sampling, that does not necessarily mean they are present for the entire year. And if emissions are not found during a limited duration sampling, that does not mean significant emissions are not occurring at other times. Extrapolating from limited measurements to an entire year therefore creates risk of either over or under counting actual emissions.

While top-down measurement methods, including satellite and aerial methods, have proven their ability to identify and measure large emissions events, their detection limits may be too high to detect emissions from sources with relatively low emission rates.[16] The data provided by some of these technologies are at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level and have high minimum detection limits. So while these technologies can provide very useful information about emissions during snapshots in time, and thus help to greatly improve the completeness and accuracy of emission reporting, they generally cannot by themselves estimate annual emissions. This rule proposes to use these top-down methods to supplement the other requirements for periodic measurement and calculation of annual emissions.

In addition to the proposed use of top-down data to help identify and quantify super-emitter and other large emissions events, we invite comment on whether there are other appropriate uses of top-down data for the purposes of reporting under subpart W of the GHGRP, including what types of emission sources and emission events, what specific top-down methods may be appropriate, especially in terms of spatial scale and minimum detection limits. As described above, the different types of top-down data have a wide range of detection limits and spatial resolution, which makes it difficult to reliably convert point estimates to an annual emissions estimate as required by the GHGRP. Therefore, this proposal does not propose using top-down approaches for sources other than besides other large release events due to the limitations described earlier in this section. However, we invite comment on whether there are top-down approaches that could be used to estimate annual emissions for any source categories under subpart W or for facility-level emissions, what level of accuracy should be required for such use, and whether the development of standards (either by the EPA or third-party organizations) could help inform this determination. We also invite comment on how frequently measurements would need to be conducted to be considered reliable or representative of annual emissions for reporting purposes.

We invite comment on how best to combine top-down data with bottom-up methods in a way that avoids double counting of emissions. For example, top-down data may be used to refine emission estimates for particular sources or for the facility. We also seek comment on the best methods to estimate duration of events measured using top-down measurements and extrapolation to annual emissions. We also invite comment on the associated modeling necessary to incorporate top-down data and the associated uncertainties for calculating facility-level emissions. We also request comment on how to account for the types of limitations described in this section.

C. Revisions to Reporting Requirements To Improve Verification and Transparency of the Data Collected

The EPA is proposing several revisions to existing reporting requirements to collect data that would improve verification of reported data and ensure accurate reporting of emissions or improve the transparency of the data collected. Such revisions would better enable the EPA to obtain data that is of sufficient quality and granularity that it can be used to support a range of future climate change policies and regulations under the CAA, including but not limited to information relevant to carrying out CAA section 136, provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs under the CAA.

We are proposing to add or revise reporting requirements to better characterize the emissions for several emission sources. For example, we are proposing to collect additional information from facilities with liquids unloadings to differentiate between manual and automated unloadings.

Other proposed revisions to the rule include changes that would better align reporting with the calculation methods in the rule. For example, we are proposing to revise reporting requirements related to atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids that follow the methodology specified in 40 CFR 98.233(j)(3) and equation W–15. The current calculation methodology uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in existing 40 CFR 98.236(j)(2)(i)(E) and (F) require reporters to delineate the counts used in equation W–15. Based on feedback from reporters, the EPA's assessment in this proposal is that the reporting requirements are inconsistent with the language used in the calculation methodology and are not inclusive of all equipment to be included. Therefore, we are proposing to revise the reporting requirements to better align the requirement with the calculation methodology and streamline the requirements for all facilities reporting atmospheric storage tanks emissions using the methodology in 40 CFR 98.233(j)(3).

In some cases, we are proposing to remove duplicative reporting elements within or across GHGRP subparts to reduce data inconsistencies and reporting errors. For example, we are proposing to eliminate duplicative reporting between subpart NN (Suppliers of Natural Gas and Natural Gas Liquids) and subpart W where both subparts require similar data elements to be reported to the electronic Greenhouse Gas Reporting Tool (e-GGRT). For instance, for fractionators of natural gas liquids (NGLs), both subpart W (under the Onshore Natural Gas Processing segment) and subpart NN require reporting of the volume of natural gas received and the volume of NGLs received. The proposed amendments would limit the reporting of these data elements to facilities that do not report under subpart NN, thus removing the duplicative requirements from subpart W for facilities that report to both subparts. This would improve the EPA's ability to verify the reported data across subparts.

[16] Duren, *et al.* "California's methane super-emitters." *Nature*, Vol. 575, Issue 7781, pp. 180–184, available at *https://doi.org/10.1038/s41586-019-1720-3.* 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

D. Technical Amendments, Clarifications, and Corrections

We are proposing other technical amendments, corrections, and clarifications that would improve understanding of the rule. These revisions primarily include revisions of requirements to better reflect the EPA's intent or editorial changes. Some of these proposed changes result from consideration of questions raised by reporters through the GHGRP Help Desk or e-GGRT. In particular, we are proposing amendments for several source types that would emphasize the original intent of certain rule requirements, such as reported data elements that have been misinterpreted by reporters. In several cases, the misinterpretation of these provisions may have resulted in reporting that is inconsistent with the rule requirements. The proposed clarifications would increase the likelihood that reporters will submit accurate reports the first time. For example, the EPA is proposing to revise the definition of variable ''T_t'' in existing equation W–1 (proposed equation W–1B) in 40 CFR 98.233 and the corresponding reporting requirements in proposed 40 CFR 98.236(b)(4)(ii)(C)(*4*), (b)(4)(iii)(C)(*3*), and (b)(5)(i)(C)(*2*) to use the term ''in service (*i.e.*, supplied with natural gas)'' rather than ''operational'' or ''operating.'' This proposed revision would emphasize the EPA's intent that the average number of hours used in equation W–1 should be the number of hours that the devices of a particular type are in service (*i.e.*, the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed). These proposed clarifications and corrections would also reduce the burden associated with reporting, data verification, and EPA review. Additional details of these types of proposed changes are discussed in section III of this preamble.

We are also proposing to revise applicability provisions for certain industry segments and applicable calculation methods. For example, we are proposing to revise the definition of the Onshore Natural Gas Processing industry segment to remove the gas throughput threshold so that the applicable industry segment and calculation methods are defined from the beginning of the year. The current definition of the Onshore Natural Gas Processing industry segment includes processing plants that fractionate gas liquids and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 million standard cubic feet (MMscf) per day or greater. Processing plants that do not fractionate gas liquids and have an annual average throughput of less than 25 MMscf per day may be part of a facility in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold do not know until the end of the year whether they will be above or below the threshold, so they must be prepared to report under whichever industry segment is ultimately applicable. Therefore, as discussed in greater detail in section III.A.3 of this preamble, we are proposing to revise the Onshore Natural Gas Processing industry segment definition in 40 CFR 98.230(a)(3) to remove the 25 MMscf per day threshold and more closely align subpart W with the definitions of natural gas processing in other rules (*e.g.*, NSPS OOOOa). This proposed revision to the Onshore Natural Gas Processing industry segment definition would better define whether a processing plant would be classified as an Onshore Natural Gas Processing facility or as part of an Onshore Petroleum and Natural Gas Gathering and Boosting facility, and the applicable segment would not have the potential to change from one year to the next simply based on the facility throughput.

Additional details of these types of proposed changes may be found in section III of this preamble.

Other minor changes being proposed include correction edits to fix typos, minor clarifications such as adding a missing word, harmonizing changes to match other proposed revisions, reordering of paragraphs so that a larger number of paragraphs need not be renumbered, and others as reflected in the draft proposed redline regulatory text in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

III. Proposed Amendments to 40 CFR Part 98

This section summarizes the specific substantive amendments proposed for subpart W (as well as subparts A and C), as generally described in section II of this preamble. Section III.A describes amendments that affect reporting responsibility or applicability. Sections III.B through III.U of this preamble describe proposed technical amendments that would affect specific source types or industry segments. We are also proposing the miscellaneous subpart W technical corrections and clarifications listed in section III.V of this preamble. We are also proposing related confidentiality determinations for new or revised data elements that result from these proposed amendments, as discussed in section V of this preamble. The impacts of the proposed revisions are summarized in section VI of this preamble. A full discussion of the cost impacts for the proposed revisions may be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

A. General and Applicability Amendments

1. Ownership Transfer

When there is a change in ownership for facilities reported under the GHGRP, the provisions of existing 40 CFR 98.4(h) describe the responsibilities of the owners and operators. However, asset transactions between owners and operators sometimes involve only some emission sources at the facility rather than the entire facility, particularly in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments in subpart W (which are two of the industry segments that have unique definitions of ''facility''). In those cases, reporters have submitted numerous questions to the GHGRP Help Desk requesting guidance regarding which owner or operator should report for the year in which the transaction occurred as well as which owner or operator is responsible for submitting revisions and responding to questions from the EPA regarding previous annual GHG reports. To assist manufacturers regarding some of these questions, the EPA previously developed Frequently Asked Questions (FAQ) Q749.[17] However, neither the FAQ nor the existing requirements in subpart A explicitly explain the responsibilities for the situations for which reporters have requested guidance.

Therefore, the EPA is proposing to add specific provisions to subpart A in

[17] U.S. EPA. Q749: ''*What are the notification requirements when an Onshore Petroleum and Natural Gas Production facility, reporting under subpart W, sells wells and associated equipment in a basin*?'' September 26, 2019. *https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183.* Note that although FAQ Q749 specifically describes facilities in the Onshore Petroleum and Natural Gas Production segment, the EPA does consider the scenarios described to be relevant to the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment as well, because facilities in both segments are defined at the basin level rather than at the level of the subpart A definition of facility.

a proposed new paragraph 40 CFR 98.4(n) that would apply in lieu of existing 40 CFR 98.4(h) for changes in the owner or operator of a facility in the four industry segments in subpart W (Petroleum and Natural Gas Systems) that have unique definitions of facility. The proposed provisions would define which owner or operator is responsible for current and future reporting years' reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2025 reports. The proposed provisions would also specify when an owner or operator would submit an annual report using an e-GGRT identifier assigned to an existing facility and when an owner or operator would register a new facility in e-GGRT. As described in more detail in this section, the provisions would vary based upon whether the selling owner or operator would retain any emission sources, the number of purchasing owners or operators, and whether the purchasing owners or operators already report to the GHGRP in the same industry segment and basin or state (as applicable). These proposed revisions are expected to improve data quality as described in section II.C of this preamble by ensuring that the EPA receives a more complete data set, and they are also expected to improve understanding of the rule, as described in section II.D of this preamble.

We expect all the transactions fall into one of four general categories, and we are proposing provisions that would define the responsibilities for reporting for each of those general categories. First, if the entire facility is sold to a single purchaser and the purchasing owner or operator does not already report to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the facility's certificate of representation must be updated within 90 days of the transaction to reflect the new owner or operator. In other words, the e-GGRT identifier and associated facility within e-GGRT would be transferred from the seller to the purchaser. The purchasing owner or operator would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.*, the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter. In addition, because the definitions of facility for each of these segments encompass all of the emission sources in a particular geographic area (*i.e.*, basin, state, or nation), the purchasing owner or operator would include any other applicable emission sources already owned by that purchasing owner or operator in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred. The purchasing owner or operator would also become responsible for responding to EPA questions and making any necessary revisions to annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. This scenario is the most similar to ownership transfer for facilities in other subparts, and this proposed amendment would specify that the responsibility for reporting should be similar to the existing requirements for all subparts.

Second, if the entire facility is sold to a single purchaser and the purchasing owner or operator already reports to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the purchasing owner or operator would merge the acquired facility with their existing facility for purposes of reporting under the GHGRP. In other words, the acquired facility would become part of the purchaser's existing facility under the GHGRP and emissions for the combined facility would be reported under the e-GGRT identifier for the purchaser's existing facility. The purchaser would update the acquired facility's certificate of representation within 90 days of the transaction to reflect the new owner or operator. The purchaser would then follow the provisions of 40 CFR 98.2(i)(6) to notify the EPA that the purchased facility has merged with their existing facility and would provide the e-GGRT identifier for the merged, or reconstituted, facility. Finally, the purchaser would be responsible for submitting the merged facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.*, the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter. The purchasing owner or operator would also become responsible for responding to EPA questions and making any necessary revisions to annual GHG reports for the purchased facility for reporting years prior to the reporting year in which the acquisition occurred. In this scenario, an entire facility is changing ownership, and this proposed amendment would specify that the responsibility for reporting should be similar to the existing requirements for all subparts.

Third, if the selling owner or operator retains some of the emission sources and sells the other emission sources of the seller's facility to one or more purchasing owners or operators, we are proposing that the selling owner or operator would continue to report under subpart W for the retained emission sources unless and until that facility meets one of the criteria in 40 CFR 98.2(i) and complies with those provisions. Each purchasing owner or operator that does not already report to the GHGRP in that industry segment (and basin or state, as applicable) would begin reporting as a new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new facility would include the acquired applicable emission sources as well as any previously owned applicable emission sources. We note that, under the proposed provisions, because the new facility would contain acquired emission sources that were part of a facility that was subject to the requirements of part 98 and already reporting to the GHGRP, the purchasing owner or operator would follow the provisions of 40 CFR 98.2(i) and continue to report unless and until one of the criteria in 40 CFR 98.2(i)(1) through (6) are met, instead of comparing the facility's emissions to the reporting threshold in 40 CFR 98.231(a) to determine if they should begin reporting. Each purchasing owner or operator that already reports to the GHGRP in that industry segment (and basin or state, as applicable) would add the acquired applicable emission sources to their existing facility for purposes of reporting under subpart W and would be responsible for submitting the annual report for their entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

Fourth, if the selling owner or operator does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchasing owner or operator, we are proposing that the selling owner or operator for the existing facility would notify the EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. The purchasing owners or operators would begin submitting annual reports for the acquired emission sources for the reporting year in which the acquisition occurred following the same provisions as in the third scenario. In other words, each owner or operator would either begin reporting their acquired applicable emission sources as a new facility or add the acquired applicable emission sources to their existing facility.

Finally, for the third and fourth types of transactions, we are proposing one set of provisions to clarify responsibility for annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. This set of proposed provisions would apply to annual GHG reports for facilities where these types of transactions occur after the effective date of the final amendments, if adopted. In other words, if the effective date of the final amendments is January 1, 2025, as described in section V of this preamble, then for ownership transactions that occur on or after January 1, 2025, we are proposing that the proposed requirements for the current and future reporting years described in the previous paragraphs would apply. In addition, the proposed provisions for annual GHG reports for reporting years prior to the transaction would also apply. For example, if an ownership transaction occurs on June 30, 2027, then the selling owner or operator and purchasing owner or operator would follow the proposed applicable provisions previously described in this section for the RY2027 report and for future reporting years. In this example scenario, the proposed provisions described in the next paragraph would apply for RY2026 and prior years' reports.

Specifically, we are proposing that as part of the third and fourth types of ownership change described previously in this section, the selling owner or operator and each purchasing owner or operator would be required to select by an agreement binding on the owners and operators (following the procedures specified in 40 CFR 98.4(b)) a ''historic reporting representative'' that would be responsible for revisions to annual GHG reports for previous reporting years within 90 days of the transaction. The EPA expects that the agreement regarding the historic reporting representative would be entered into at the time of the acquisition and that if the representative responsible for revisions to annual GHG reports is not employed by the selling owner or operator, copies of the records required to be retained per 40 CFR 98.3(g) and (h) would be transferred to the historic reporting representative at that time. The historic reporting representative for each facility that would respond to any EPA questions regarding GHG reports for previous reporting years and would submit corrected versions of GHG reports for previous reporting years as needed. In many situations, the EPA expects that the purchaser would agree to select a historic reporting representative to address revisions to previous years' annual GHG reports. In particular, there may be cases in which the selling owner or operator's company will no longer be operating after the transaction, so it may be appropriate for one of the purchasing owners or operators to select that historic reporting representative. In other situations, the parties may determine that it is appropriate for the seller to select the historic reporting representative to address revisions to annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. In the 2022 Proposed Rule, the EPA proposed that if this historic reporting representative is not the current designated representative for the facility, the historic reporting representative would need to be appointed as the alternate designated representative or an agent for the facility. However, in some cases this could provide that individual with access to the facility's data for reporting years other than the previous reporting years for which that individual is responsible, including potentially confidential or sensitive information and correspondence. Therefore, the EPA is not proposing to specify that the historic reporting representative would be required to be appointed as the alternate designated representative or an agent for the facility.

Finally, we are proposing to amend 40 CFR 98.2(i)(3), the current provision that allows an owner or operator to discontinue reporting to the GHGRP when all applicable processes and operations cease to operate. Through correspondence with reporters via e-GGRT, we are aware that there have been times that an owner or operator divested a facility and was therefore no longer required to report the emissions from that facility, but even though the facility changed owners and did not cease operating, the selling owner or operator chose the provisions of existing 40 CFR 98.2(i)(3) as the reason they were ceasing to report because none of the other options fit the situation. The EPA's intent is that this reason for no longer reporting to the GHGRP should only be used in cases in which all the applicable sources permanently ceased operation. Therefore, we are proposing to clarify that 40 CFR 98.2(i)(3) would not apply when there is a change in the owner or operator for facilities in these four industry segments, unless the changes result in permanent cessation of all applicable processes and operations.

2. Definition of ''Owner'' and ''Operator''

We are also proposing to amend 40 CFR 98.1(c) to clarify that the terms ''owner'' and ''operator'' used in subpart A have the same meaning as the terms ''gathering and boosting system owner or operator'' and ''onshore natural gas transmission pipeline owner or operator'' for the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipeline industry segments of subpart W, respectively. This paragraph was inadvertently not amended when those two industry segments and the industry segment-specific definitions of owner or operator were added to subpart W (80 FR 64275, October 22, 2015), and this proposed amendment would correct that oversight, consistent with section II.D of this preamble.

3. Onshore Natural Gas Processing Industry Segment Definition

According to existing 40 CFR 98.230(a)(3), the Onshore Natural Gas Processing industry segment currently includes all facilities that fractionate NGLs. The industry segment also includes all facilities that separate NGLs from natural gas or remove sulfur and carbon dioxide (CO_2) from natural gas, provided the annual average throughput at the facility is 25 MMscf per day or greater. The industry segment also includes all residue gas compression equipment owned or operated by natural gas processing facilities that is not located within the facility boundaries.

One stakeholder expressed concern that the current definition of the Onshore Natural Gas Processing industry segment applies to some compressor stations simply because they have an amine unit that is used to remove sulfur and CO_2 from natural gas.[18] According to this stakeholder, it would be more appropriate for such facilities to be in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. This stakeholder also explained that the 25 MMscf per day threshold creates additional burden and uncertainty for these compressor station facilities because they do not know until the end of the year whether they will be above or below the threshold. Thus,

[18] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

they need to collect the applicable data for both the Onshore Natural Gas Processing industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment so that they will have the required data for whichever industry segment ultimately applies to them. To resolve this issue and to promote consistency among regulatory programs, this stakeholder recommended replacing the onshore natural gas processing definition in subpart W with the natural gas processing plant definition in NSPS OOOOa.

After consideration of this issue, we are proposing to replace the definition of ''Onshore natural gas processing'' in 40 CFR 98.230(a)(3) with language similar to the definition of ''natural gas processing plant'' in NSPS OOOOa. This proposed amendment would improve the verification and transparency of the data, particularly across reporting years, consistent with section II.C of this preamble, and it would provide reporters with certainty about the applicable industry segment for the reporting year, consistent with section II.D of this preamble, allowing them to focus their efforts on collecting accurate monitoring data and emissions information needed for one applicable industry segment. As explained later in this section, while we expect that the proposed revisions would result in some facilities reporting under a different industry segment, we do not expect that the overall coverage of the GHGRP would decrease. Further, as the stakeholder noted, the two potentially applicable segments currently report emissions from different sources and with different calculation methods. For example, facilities in the Onshore Natural Gas Processing industry segment are currently not required to report emissions from natural gas pneumatic devices or atmospheric storage tanks and are currently required to measure leaks from individual compressors, while facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are currently required to report emissions from natural gas pneumatic devices or atmospheric storage tanks but currently use population emission factors to calculate emissions from all compressors rather than conducting measurements. However, the proposed addition of emission sources to the Onshore Natural Gas Processing industry segment (as described in section III.C.1 of this preamble) would remove the differences in the emission sources reported by facilities in one industry segment and not the other. The addition of calculation methodologies for specific emission sources that would be calculated and reported by facilities in both industry segments would result in fewer differences between the emissions reported under the two industry segments.[19]

NSPS OOOOa defines ''natural gas processing plant (gas plant)'' as any processing site engaged in the extraction of NGLs from field gas, fractionation of mixed NGLs to natural gas products, or both. The definition specifies that a Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant. There are two minor editorial differences between the proposed definition in 40 CFR 98.230(a) and the definition in NSPS OOOOa. First, instead of defining a natural gas processing ''plant,'' as in the definition in NSPS OOOOa, we are proposing to describe what is meant by ''natural gas processing'' so that the structure of 40 CFR 98.230(a)(3) is consistent with the structure of all of the other industry segment definitions in 40 CFR 98.230(a). Second, the definition in NSPS OOOOa refers to ''extraction'' of NGLs from natural gas, but this term is not defined. Thus, we are proposing to retain the term ''forced extraction'' in the current provisions of 40 CFR 98.230(a)(3) and proposing to revise the definition of this term slightly in 40 CFR 98.238. The current definition of ''forced extraction'' specifies that forced extraction does not include ''portable dewpoint suppression skids.'' We are proposing to revise the definition to indicate instead that forced extraction does not include ''a Joule-Thomson valve, a dewpoint depression valve, or an isolated or standalone Joule-Thomson skid.'' These changes would make the definition of ''forced extraction'' in subpart W consistent with the language in the definition of a natural gas processing plant in NSPS OOOOa.

The proposed amendments to the processes that are considered ''onshore natural gas processing'' are not expected to decrease overall coverage of the GHGRP for the petroleum and natural gas systems industry, although we anticipate that some operations currently being reported as standalone facilities under the Onshore Natural Gas Processing industry segment would transition to reporting as part of either existing or new facilities under the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, while some operations currently being reported as part of Onshore Petroleum and Natural Gas Gathering and Boosting facilities would transition to reporting as standalone facilities under the Onshore Natural Gas Processing industry segment. For example, based on reported data for RY2020, about 19 percent of facilities reporting in the Onshore Natural Gas Processing industry segment do not fractionate NGLs and report zero NGLs received and leaving the facility. These facilities meet the current definition of natural gas processing because they are separating CO_2 and/or hydrogen sulfide and/or they are capturing CO_2 separated from natural gas. These facilities would not meet the proposed revised definition for natural gas processing and instead, their emissions would be reported as part of either existing or new onshore petroleum and natural gas gathering and boosting facilities. In most cases, we anticipate that operations at a facility that was previously classified by a reporter as a gas processing facility would be incorporated into an existing gathering and boosting facility that has been subject to reporting, and the total emissions from the expanded gathering and boosting facility would be similar to the emissions that would have been reported by the separate facilities under the existing industry segment definitions. In cases where a former gas processing facility is located in a basin where the owner or operator does not have an existing reporting gathering and boosting facility, we expect that a new gathering and boosting facility including the former gas processing facility would be created because the emissions from the former gas processing facility alone would exceed the reporting threshold of 25,000 $mtCO_2e$. If the same owner or operator has other gathering and boosting operations in the same basin that have emissions less than 25,000 $mtCO_2e$, then the new gathering and boosting facility could result in increased coverage of the industry segment and greater total reported emissions than would be reported under

[19] Proposed amendments described throughout the remainder of this preamble would reduce the differences in calculation methodologies (*e.g.*, see sections III.O and III.P of this preamble), but there are still expected to be differences even if all the proposed amendments are finalized. The differences in calculation methodologies that would remain are due to differences in the types of operations and other factors such as the size of the ''facility'' between the two industry segments. In particular, facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment can be geographically dispersed, and as such, some measurement methodologies may be optional rather than required. In addition, the combustion emissions for facilities in the Onshore Natural Gas Processing industry segment are reported under subpart C, while the combustion emissions for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are reported under subpart W.

the current industry segment definitions.

The proposed revised definition for natural gas processing also does not include the 25 MMscf per day threshold for facilities that separate NGLs from natural gas using forced extraction but do not fractionate NGLs. Under the current definition of onshore natural gas processing, processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold may be natural gas processing facilities one year and then part of an onshore petroleum and natural gas gathering and boosting facility the next year. As noted earlier in this section, the two potentially applicable segments currently report emissions from different sources and with different calculation methods. As a result of the current definition, it can be difficult to track the reporting status of a facility from one year to the next, and it can be difficult to assess and verify reporting trends for an individual facility across reporting years. Under the revised proposed definition, these sites that separate NGLs from natural gas using forced extraction but do not fractionate NGLs and generally operate close to 25 MMscf per day would be considered natural gas processing regardless of their throughput level, so they would have the certainty of knowing they would be subject to reporting as natural gas processing facilities every year. As a result, removing the 25 MMscf per day threshold is expected to increase the number of sites that consistently report as facilities under the Onshore Natural Gas Processing industry segment instead of sometimes reporting as part of a facility that reports under the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. We request comment on the impact the proposed changes would have on the number of reporting facilities and emissions from both the Onshore Natural Gas Processing and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. We also request comment on any other advantages or disadvantages to finalizing the proposed changes.

4. Applicability of Proposed Subpart B to Subpart W Facilities

In the supplemental proposal to the 2022 Proposed Rule (88 FR 32852, May 22, 2023), the EPA is proposing to add subpart B to part 98 (Metered, Non-fuel, Purchased Energy Consumption by Stationary Sources) for reporting the quantity of metered electricity and thermal energy purchased. The EPA's intent is for this new subpart to apply to facilities that are required to report direct emissions under another subpart of the GHGRP, including those facilities in subpart W industry segments that have a unique definition of facility in 40 CFR 98.238 and a reporting threshold specified in 40 CFR 98.231. Therefore, the EPA is proposing to add 40 CFR 98.232(n) (and a reference to this new paragraph from the introductory text of 40 CFR 98.232) to clarify the intent for subpart W reporters to also report under subpart B, consistent with section II.D of this preamble.

B. Other Large Release Events

We are proposing to add an additional emissions source, referred to as ''other large release events,'' to capture maintenance or abnormal emission events that are not fully accounted for using existing methods in subpart W, consistent with section II.A of this preamble. Numerous studies have indicated that other large release events, commonly referred to as ''super-emitters,'' significantly contribute to the emissions from oil and gas facilities and that the current subpart W understates oil and gas emissions because there is a lack of calculation and reporting requirements for many of these large events.[20] We proposed to include calculation and reporting requirements for other large release events in the 2022 Proposed Rule, and this proposal regarding other large release events is very similar to the 2022 Proposed Rule. The primary difference in this proposal is that we are including an instantaneous CH_4 emission rate threshold of 100 kg/hr, in addition to the 250 mtCO_2e per event threshold we previously proposed, so there are two proposed emissions thresholds for determining whether emissions from other large release events must be reported. We are also proposing to expand the definition of other large release events to include planned releases, such as those associated with maintenance activities for which there are not emission calculation procedures in subpart W. Emptying, degassing, and cleaning a tank is an example of a maintenance activity for which emissions would need to be reported under this proposal (if the emissions exceed the thresholds for an other large release event) that would not have been required to report under the 2022 Proposed Rule's definition of other large release event.

Most of the emission sources and methodologies included in subpart W characterize emissions that routinely occur at oil and gas facilities as part of their normal operations, including routinely occurring large emission events, such as blowdowns. While some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector and have been studied and characterized and these types of events have been incorporated into existing subpart W source methodologies. On the other hand, there have been several large, atypical release events at oil and gas facilities over the last few years where it was difficult to sufficiently include these emissions in annual GHGRP reports. For example, a storage wellhead leak at Aliso Canyon released approximately 100,000 metric tons (mt) of CH_4 between October 2015 and February 2016 [21] and a well blowout in Ohio released an estimated 40,000 to 60,000 tons of CH_4 in a 20-day period in 2018.[22] The emissions from these types of releases were not well represented using the existing calculation methodologies in subpart W because these were not common or predictable events.[23] For example, subpart W includes a default emission factor for underground gas storage wellheads to estimate emissions from leaking storage wellheads; however, the data upon which that emission factor is based do not include a release of the magnitude estimated for Aliso Canyon

[20] See, *e.g.*, Zavala-Araiza, D., et al., 2017, Super-emitters in natural gas infrastructure are caused by abnormal process conditions, *Nat. Commun. 8*, 14012, *https://doi.org/10.1038/ncomms14012*; Alavarez, R.A., *et al.*, 2018, Assessment of methane emissions from the U.S. oil and gas supply chain, *Science 361*(6398) 186–188, *https://www.science.org/doi/10.1126/science.aar7204*; Chen, Y., *et al.*, 2022, Quantifying regional methane emissions in the New Mexico Permian Basin with a comprehensive aerial survey, *Environmental Science & Technology 56*(7) 4317–4323, *https://doi.org/10.1021/acs.est.1c06458*. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[21] California Air Resources Board. 2016. *Determination of Total Methane Emissions from the Aliso Canyon Natural Gas Leak Incident.* Available at *https://ww2.arb.ca.gov/sites/default/files/2020-07/aliso_canyon_methane_emissions-arb_final.pdf*. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[22] Pandey, S., *et al.*, 2019. Satellite observations reveal extreme methane leakage from a natural gas well blowout. *Proceedings of the National Academy of Sciences 116*(52), 26376–26381. *https://doi.org/10.1073/pnas.1908712116*. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[23] The EPA notes that the full emissions from these events were included in the U.S. GHG Inventory based on the results of multiple measurement studies. See U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2020: Updates for Anomalous Events including Well Blowout and Well Release Emissions.* April 2022. Available at *https://www.epa.gov/system/files/documents/2022-04/2022_ghgi_update_-_blowouts.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

because this type of malfunction did not occur during the measurement study. Recent data summarizing release events from underground storage facilities indicate that while the Aliso Canyon release was large, it was not the largest release event from an underground storage facility and that, over the past 75 years, there have been 129 release events from underground storage facilities.[24] The data showed emissions from these release events are heavy-tailed with event emissions spanning 6 orders of magnitude, indicating that they would not likely be accurately described by an emission factor. Rather than escalating the population emission factor for all storage wellheads to account for these releases, our assessment is that it would be more accurate for the population emission factor to be based on typical frequency and size of leaks that commonly occur and to track these uncommon, large releases separately. Because these events can significantly contribute to the total GHG emissions from this sector, we are proposing to add, at 40 CFR 98.232, other large release events as an emission source for which emissions must be calculated for every industry segment. We are also proposing new calculation methods for estimating the GHG emissions from other large release events in 40 CFR 98.233(y) and requirements for reporting other large release events in 40 CFR 98.236(y). These proposed additional calculation and reporting requirements would apply to all subpart W industry segments and would improve the accuracy of emissions reported under subpart W and enhance the overall quality of the data collected under the GHGRP.

The new calculation requirements being proposed rely on measurement data, if available, or a combination of engineering estimates, process knowledge, and best available data, when measurement data are not available. The proposed calculation procedure consists of estimating the amount of gas released and the composition of the released gas. The amount of gas released would generally be calculated based on a measured or estimated emission rate(s) and an event duration. We are proposing that the start time of the duration must be determined based on monitored process parameters, such as pressure or temperature, for which sudden changes in the monitored parameter signals the start of the event. If the monitored process parameters cannot identify the start of the event, we are proposing that reporters must assume the release started on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at the rates above the other large release event reporting thresholds or assume the duration of the event was 182 days (six months), whichever duration is shorter. We are proposing the end time of the release must be the date of the confirmed repair or confirmed cessation of emissions. There may be events that span across two separate reporting years. In this case, we are proposing that the volume of gas released specific to each reporting year would be calculated and reported for that reporting year starting with RY2025.

We request comment on the proposed default duration of 182 days (in the absence of information on the start time). Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days,[25] but in many cases they may be significantly longer, occurring for weeks or months.[26] For many releases, such as maintenance events, fires, explosions, and well blowouts, the reporter would be able to identify the start and end time of an event. Other releases may be identified via monitoring surveys or site inspections. For these the start date can often be identified from process operating records or previous monitoring results. For identifying the start date, we are specifically proposing to allow monitoring or measurement surveys to include methods specified in 40 CFR 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at the thresholds specified for an other large release event. However, there will be some releases for which the start date cannot be determined. We selected a 182-day default duration as this duration would include the majority of these types of events. We expect that facilities will typically estimate durations based on the monitoring of operating conditions, with more frequent monitoring or measurement surveys, as described above, resulting in infrequent use of the default. We recognize that the 182-day default duration may cause revisions to reports submitted for previous reporting years in some cases; however, we expect that these revisions would be made prior to the final verification of the reports for a given reporting year and should not have significant implications on being able to calculate the event emissions and submit revised reports, if needed, prior to the time waste emission filings, if applicable, are due. We request comment on the 182-day default duration and ability to revise, if necessary, subpart W reports prior to the final verification of reports for a given reporting year.

We also request comment on using other default durations. Specifically, we request comment on using a 91-day (3-month) default duration rather than 182-day duration, as well as on other potential default durations. We seek information to support default duration assumptions. We request comment on whether a 91-day default duration would be reasonable. We also request comment on using the beginning of the calendar year as the default duration. Using the beginning of the year as the default duration would eliminate issues regarding potential revisions to previously submitted reports, but it would lead to inconsistent reporting of emissions from similar types of events based on when the event occurred (or was identified) in the calendar year. For other large release events with an identifiable start date in reporting year 1 and identifiable end date in reporting year 2, some reporters may know of the release on the day it started and other reporters may not identify the release until late in the overall duration. If the reporter knows of the event in reporting year 1, then the reporter would be obligated to report the emissions that occurred from this event in each

[24] Li, H.Z., *et al.*, 2022. A national estimate of U.S. underground natural gas storage incident emissions. *Environ. Res. Lett. 17*(8) 084013. *https://doi.org/10.1088/1748-9326/ac8069.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[25] See, *e.g.*, Chen, *et al.*, Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey. *Environmental Science & Technology* (Vol. 56, Issue 7, pp. 4317–4323), available at *https://doi.org/10.1021/acs.est.1c06458.* 2022; Wang, *et al.*, Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting. *Environmental Science & Technology* (Vol. 56, Issue 20, pp. 14743–14752), available at *https://doi.org/10.1021/acs.est.2c06211.* 2022. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[26] See, *e.g.*, Frequently Asked Questions: Aliso Canyon Gas Storage Facility. Public Utilities Commission, State of California, January 26, 2021. *https://www.cpuc.ca.gov/regulatory-services/safety/gas-safety-and-reliability-branch/aliso-canyon-well-failure*; Cusworth, *et al.*, 2021, Multisatellite imaging of a gas well blowout enables quantification of total methane emissions. Geophysical Research Letters, 48, e2020GL090864. *https://doi.org/10.1029/2020GL090864*; and Maasakkers, J.D., *et al.*, 2019. Reconstructing and quantifying methane emissions from the full duration of a 38-day natural gas well blowout using space-based observations. *Remote Sensing of Environment*. 112755. *https://doi.org/10.1016/j.rse.2021.112755.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

reporting year. However, if the reporter does not become aware of the release until the second reporting year, using the start of the year as the beginning of the default duration would result in the reporter only being required to report the emissions from the other large release event that occurred in reporting year 2, resulting in underreported emissions.

We also considered hybrid alternatives where the reporter would have to evaluate company records to identify the start date and use the actual start date if known but use the start of the calendar year if not known. While there is an incentive for the reporter to review records in reporting year 2 to identify if the release event began prior to the first day of the calendar year, there would not be a similar incentive for the reporter to review records in the previous reporting year (reporting year 1). Instead, if waste emission charges may apply, there would be an incentive to simply use the default of the beginning of the year and not review records past this date. Under this hybrid alternative, we would need to specify how many months of records reporters would be required to review to determine the start date of the event. We considered both 182 and 365 days of records required to be reviewed under this alternative hybrid approach. After considering these various scenarios, we selected the 182-day maximum duration and event reporting across reporting years to be the most accurate and reasonable option, but we request comment on the other options considered as described in this section. We also seek comment on other options that may be used to obtain accurate reporting of other large release event emissions that span reporting years.

We recognize that some natural gas releases, such as explosions or fires, will combust or partially combust the natural gas released. We are proposing that reporters must estimate the portion of the total volume of natural gas released that was combusted in the explosion or fire in order to determine the average composition of GHG released to the atmosphere during the event. For the portion of natural gas released via combustion in an explosion or fire, we are proposing a maximum combustion efficiency of 92 percent be assumed. This maximum combustion efficiency is consistent with the combustion efficiency we are proposing for flares that are not continuously monitored as described in section III.N.1 of this preamble. We recognize that because these releases are not through engineered nozzles that can be designed to promote mixing and combustion efficiency, the combustion efficiency of these releases can be highly variable. Reporters may use a lower combustion efficiency but may not use higher combustion efficiency than 92 percent for natural gas released directly in an explosion or fire. We request comment on these proposed provisions. We request comment and supporting data on the proposed maximum combustion efficiency of 92 percent for the portion of the total volume of natural gas released via explosion or fire.

The proposed requirement to calculate and report GHG emissions from other large release events would be limited to events that release at least 250 $mtCO_2e$ per event or have a CH_4 emission rate of 100 kg/hr or greater at any point in time. The 250 $mtCO_2e$ per event threshold is equivalent to approximately 500,000 standard cubic feet (scf) of pipeline quality natural gas. For events that span two reporting years, we are proposing that these thresholds apply to the event, not a portion of the event within a given reporting year. We selected these proposed thresholds to capture reporting for large emission events, such as well blowouts, well releases, and large pressure relief venting.

In order to establish the mass CO_2e per event reporting threshold, we assessed other emission sources that could qualify as large. Specifically, we considered completions of hydraulically fractured wells that are not controlled (*i.e.*, not performed using reduced emission completions (RECs)) to be large emissions events. RECs are completions where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Based on analysis of GHGRP data for wells that are not RECs and that vent, the U.S. GHG Inventory developed an average emission factor of about 360 $mtCO_2e$ per event for these completions.[27] Because this is an average emission factor, some uncontrolled hydraulically fractured completions will be below this average and some above. From this assessment, we considered 250 $mtCO_2e$ to be a reasonable emissions threshold for a "large" event.

While 250 $mtCO_2e$ is much lower than the emissions from the Aliso Canyon or Ohio well blowout releases, we determined that a 250 $mtCO_2e$ threshold would be needed to capture most well blowouts. There are limited data to quantify an "average" well blowout, but the 2021 U.S. GHG Inventory uses an oil well blowout emission factor of 2.5 MMscf per event. As this is an average, many well blowouts may be less than this average value. The 250 $mtCO_2e$ threshold is approximately equivalent to 500,000 scf of natural gas, which aligns with the lower range of well blowouts expected based on the average emission factor of 2.5 MMscf per event. This value also aligns with the definitions of "major release" in New Mexico Administrative Code (NMAC) section 19.15.29.7, which requires reporting under NMAC section 19.15.29.10.

We also tentatively find that the proposed 250 $mtCO_2e$ threshold (approximately equivalent to 500,000 scf natural gas release) is a reasonable threshold for requiring individual assessments of releases. In subpart Y (Petroleum Refineries), we established event-specific emission calculation requirements for startup, shutdown, or malfunction releases to a flare exceeding 500,000 scf per day (40 CFR 98.253(b)(1)(iii)). While the subpart Y threshold is per day rather than per event, it is also specific to flared emissions. For flared emissions to exceed a 250 $mtCO_2e$ threshold, approximately 4 MMscf of natural gas would have to be released to the flare, which is well above the subpart Y "per day" threshold for flares. Thus, we propose that the 250 $mtCO_2e$ per event threshold is an appropriate size threshold for requiring event-specific emission calculations to be performed. More information regarding our review and characterization of types of other large release events is included in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. Emissions from smaller or routine release events would still be reported, as applicable, under the source-specific calculation and reporting requirements in subpart W.

We are also proposing a 100 kg/hr CH_4 emission threshold to align with the super-emitter response program proposed in the NSPS OOOOb. These emissions are generally intermittent, with widely varying durations. Releases from maintenance activities, for example, may occur for only a few hours, but these large, short events can

[27] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014*. EPA 430–R–16–002. April 2016. Available at *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2014* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

significantly contribute to a facility's emissions. The proposed emission rate threshold for a super-emitter emissions event under NSPS OOOOb provides a means to get information for these large, shorter duration releases. Therefore, we are proposing that the 100 kg/hr CH_4 emission threshold be applied as an instantaneous emissions rate threshold, such that any emissions from any other large release event that emits CH_4 at a rate of 100 kg/hr or more at any point in time must be reported.

With a combination of both a cumulative mass emissions per event threshold and the instantaneous 100 kg/hr CH_4 emission rate threshold, the EPA is requesting comment whether a larger cumulative mass emissions per event threshold is reasonable. Specifically, we understand that the Pipeline and Hazardous Materials Safety Administration (PHMSA) includes, in the definition of ''incident'' at 49 CFR 191.3, an ''unintentional estimated loss of three million cubic feet or more.'' As many subpart W facilities are required to keep records of these incidents, we request comment on the use of a 1,500 $mtCO_2e$ per event threshold, which would be approximately equivalent to a 3 million cubic feet release of natural gas. We request comment on whether the CO_2e mass threshold is appropriate for considering emissions from events such as fires, or if the threshold should be expressed as a loss of 3 million cubic feet or more of natural gas, whether directly emitted or partially burned via a fire. We also request comment on whether these thresholds should be assessed per event within the calendar year, rather than just per event. We propose that the thresholds for other large release events would be evaluated on a per event basis because then all events are considered consistently regardless of when they occur. For example, consider a 400 $mtCO_2e$ event that spans two calendar years, with 200 $mtCO_2e$ released in each calendar year. As proposed, the reporter would be required to report the other large release event in each of the corresponding reporting years. If, however, the thresholds were instead evaluated on a per event within a calendar year basis, this emissions event would not qualify as an other large release event in either reporting year. There may be cases where limiting the thresholds to events to within a calendar year could reduce the number of events reported without significantly missing emissions and potentially limiting the number of report resubmissions. For example, if the 400 $mtCO_2e$ event that spanned 2 calendar years resulted in 40 $mtCO_2e$ of emission in reporting year 1 and 360 $mtCO_2e$ of emissions in reporting year 2, then if the thresholds were evaluated on a per event per calendar year basis, only the emissions in reporting year 2 would be required to be reported. Under the thresholds as proposed, the 40 $mtCO_2e$ of emission in reporting year 1 would be required to be reported. Depending on when the other large release event was identified and start date determined, this may require resubmission of a previously submitted subpart W report. We request comment on whether the other large release event thresholds should be limited to releases within a single calendar year.

We are proposing a definition of ''other large release events'' in 40 CFR 98.238 to clarify the types of releases that must be characterized for this new emissions source and specify that other large release events include, but are not limited to, maintenance events, well blowouts, well releases, releases from equipment rupture, fire, or explosions. Currently, there are no calculation methodologies or reporting requirements for these types of large releases in subpart W. The proposed definition would also include large pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks that are not included in the blowdown definition. The proposed definition of other large release events excludes pressure relief valve releases from hydrocarbon liquids storage tanks because the calculation methodology for storage tanks is expected to account for these releases via either the proposed requirements to account for collection efficiency when emissions are observed from the thief hatch or the additional term in the emissions equation for when there is a stuck dump valve. While subpart W currently includes emission factors for pressure relief devices, these equipment leak emission factors only account for leaks past a pressure relief valve that is in the closed position, not releases from the complete opening of these valves. The proposed definition specifies that pressure relief valve releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks would not be considered other large release events because the calculation methodology for these storage tanks currently assumes all flash gas will be emitted. As noted in section III.K of this preamble, pressure relief emission releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks generally occur from the thief hatch and these releases must be accounted for when calculating the fraction of flash gas that is recovered or sent to a flare, if applicable. A more detailed discussion of certain other emissions events we have identified and expect to be subject to the ''other large release events'' proposed amendments is included in the subpart W TSD available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

As part of the proposed definition of ''other large release events'' in 40 CFR 98.238, we are also proposing that other large release events include releases from equipment for which the existing calculation methodologies in subpart W would significantly underestimate the episodic nature of these emissions. For example, subpart W contains population emission factors and leaker emission factors for estimating equipment leak emissions for storage wellheads. Thus, it is possible to argue that subpart W includes calculation methodologies for the equipment responsible for the Aliso Canyon release. However, the calculation methodologies in subpart W do not accurately estimate emissions from such an uncharacteristically large release event because such events are infrequent such that they may not exist when measurement studies are conducted. Additionally, if we proposed to instead revise the emission factors under the existing methodologies to account for such an event, the resulting calculation would likely yield erroneously high emissions from normal operations for most reporting facilities. Thus, we determined that it is more accurate for facility-specific reporting to account for these large releases on a per event basis. Therefore, if a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in subpart W by 250 $mtCO_2e$ or more on a per event basis, or 100 kg/hr of CH_4 or more as an instantaneous rate at any time during an event, we are proposing that such releases would be included in the definition of ''other large release events'' and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release events. We are proposing in 40 CFR 98.233(y)(1)(ii) that this provision does not require the direct measurement of every release, such as measurement of every leak identified during an equipment leak monitoring survey. However, we are proposing to require that if the owner or operator has credible information that demonstrates that the release meets or exceeds or may reasonably be anticipated to meet or exceed (or to have met or have exceeded) the emissions calculated by the source-specific methodology by 250 mtCO_2e or more, or 100 kg/hr of CH_4 or more, then the release must be quantified and, if the thresholds are confirmed to be exceeded, reported as an other large release event. We consider credible information would include, but is not limited to, data from monitoring or measurement data completed by the facility, information from notifications as a potential super-emitter emissions event under the super-emitter provisions of NSPS OOOOb at proposed 40 CFR 60.5371b or data of similar quality as that provided through the provisions of NSPS OOOOb at proposed 40 CFR 60.5371b that is received by the facility. We anticipate that we would take into consideration what is included in the final NSPS OOOOb regarding such notifications in the types of information that would be considered credible for these provisions in subpart W, if finalized. The owner or operator would be required to consider all credible information they have regarding the release in complying with this requirement.

Further, we are proposing to define the terms ''well release'' and ''well blowout'' in 40 CFR 98.238 to assist reporting facilities with differentiating between these types of release events that could potentially occur at wells. We find that a well blowout is generally distinguished by a complete loss of well control for a long duration of time and a well release is characterized as a short period of uncontrolled release (not the controlled pre-separation stage of well flowback in a hydraulically fractured completion) followed by a period of controlled release in which control techniques were successfully implemented.

Finally, we are proposing a series of reporting requirements in 40 CFR 98.236(y) related to the type, location, duration, calculations, and emissions of each ''other large release event.'' Specifically, we are proposing that reporters provide the location, a description of the release (from a specified list that includes an ''other (specify)'' option for releases that are not described well with the list provided), a description of the technology or method used to identify the release, volume of gas released, volume fractions of CO_2 and CH_4 in the gas released, and CO_2 and CH_4 emissions for each ''other large release event.'' We are also proposing that reporters would provide the start date and time of the release, duration of the release, and the method used to determine the start date and time (options would include a pressure monitor, a temperature monitor, other monitored process parameter, most recent monitoring or measurement survey showing no large release, or the default assumption that the release started 182 days prior to the documented end of the release (this would be the required assumption if they do not have monitored data associated with the release). We are also proposing that reporters provide a general description of the event and indicate whether the ''other large release event'' was also identified as a potential super-emitter emissions event under the super-emitter provisions of NSPS OOOOb at 40 CFR 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.

We are proposing that reporters that received super-emitter emissions event notifications would be required to report information on each release notification received, including latitude and longitude of the release, whether the release was received under the super-emitter provisions of NSPS OOOOb at 40 CFR 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 or another notifier. If the notification is from another notifier, the reporter would provide the name of the notifier, the remote sensing method used, the date and time of the measurement, the measured emission rate, and uncertainty bounds on the emission rate, if provided by the notifier. We are also proposing that, for each notification received, facilities would report the type of event resulting in the emissions (*e.g.*, normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device, or undetermined cause) and an indication of whether the emissions identified from the event are included as an other large release event or as another source required to be reported under subpart W. If the emissions identified via the notification are not included in emissions reported under subpart W, we are proposing that the reporter provide a reason (*e.g.*, the location of the emissions as provided in the notification do not belong to the facility; the emissions could not be verified or corroborated during site inspection or facility data records; information was determined to not be credible and basis for the determination). This information would support EPA verification and ensure accuracy of the emissions reported under other large release events.

As part of the GHGRP verification process, the EPA reviews data provided in submitted reports to identify potential errors in the reported data based on the different values reported and the calculation methodology. The EPA requests comment on the need to establish additional requirements for third-party notifiers and the verification of third-party notifications. Generally, verification of GHGRP reports is conducted while a facility is entering data into the e-GGRT system and after the report is officially submitted. The EPA requests comment on the need for EPA verification support or an advance verification process during the reporting year for assessments of third-party notifications. Currently, facilities with questions about reporting requirements submit inquiries via the e-GGRT Help Desk to get questions answered regarding monitoring or reporting requirements. We request comment on whether this existing process is adequate for supporting questions regarding individual third-party notifications received by a reporter and request suggestions on how the EPA verification process could better support the other large release event calculation and reporting requirements.

The supplemental proposal for NSPS OOOOb and EG OOOOc, as described in section II of this preamble, included a matrix for alternative screening approaches for fugitive emissions from well sites and compressor stations that would allow the use of advanced measurement technologies to detect emissions under the proposed NSPS OOOOb and EG OOOOc. As part of that proposal, the EPA also requested comment on how to evaluate and design a requirement for owners and operators to investigate and remediate large emission events, which could include the use of alternative screening techniques and advanced measurement technologies, all of which, if finalized, could potentially be used to identify ''other large release events'' under subpart W. While some methods that could be used to identify and estimate the magnitude of these ''other large release events,'' such as monitors installed on mobile vehicles or aircraft or CH_4 satellite imagery, would not be specifically included as measurement methods listed in 40 CFR 98.234 of subpart W, these methods may be used to quantify the emissions release for ''other large release events'' under the ''engineering estimates'' and ''best available data'' provisions of the proposed calculation methodology. To improve the EPA's understanding of the technologies and methods used to identify reported ''other large release events,'' including the impact of periodic screenings with advanced measurement technologies on the identification of large release events, we are proposing reporting provisions that would require reporters to indicate whether each ''other large release event'' was identified as part of compliance with NSPS OOOOb or the applicable state plan or applicable Federal plan in 40 CFR part 62.

C. New and Additional Emission Sources

Sources of emissions that are required to be reported to subpart W are listed in 40 CFR 98.232 for each industry segment, with the methodology and reporting requirements for each source provided in 40 CFR 98.233 and 98.236, respectively. The EPA finalized this list of emission sources for each of the eight original industry segments as part of the 2010 Final Rule and identified emission sources for the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipeline industry segments when those segments were added to subpart W in 2015 (80 FR 64262, October 22, 2015). Per the TSD for the 2010 Final Rule (hereafter referred to as the ''2010 subpart W TSD''),[28] there were several factors that impacted the EPA's decision on whether an emissions source should be included for reporting. These factors included how significant the contribution of the source was to the U.S. GHG Inventory, the type of emission expected from the source (vented versus fugitive), the best practice monitoring methods available to measure emissions from the source, accessibility of the emission source, geographical dispersion of the emission source, and the applicability of population versus leaker factors.

The EPA has evaluated the sources covered under subpart W in comparison with present-day inventories of the oil and gas industry, such as the 2022 U.S. GHG Inventory [29] and the American Petroleum Institute (API) 2021 *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* (2021 API Compendium).[30] The EPA also reviewed stakeholder feedback, including public comments from the 2022 Proposed Rule, on missing sources of emissions from subpart W. As a result, the EPA is proposing to add several emission sources identified in this review that are anticipated to have a meaningful impact on reported emissions, are commonplace in the oil and gas industry, and/or have existing emission calculation methodologies and reporting provisions in the current subpart W regulatory text. For some of these emission sources, discussed in additional detail in section III.C.1 of this preamble, reporting is currently required for some, but not all, industry segments in which they exist. Other proposed emission sources, discussed in additional detail in sections III.C.2 through 5 of this preamble, are not currently required to be reported for any industry segments in which they exist. The proposed addition of sources to subpart W would be expected to enhance the overall quality of the data collected under the GHGRP and improve the accuracy of total emissions reported from facilities, consistent with Congress' direction in the IRA and section II.A of this preamble.

The following sections detail the proposed additions of emission sources to subpart W.

1. Current Subpart W Emission Sources Proposed for Additional Industry Segments

Upon review of the U.S. GHG Inventory and the 2021 API Compendium, as well as other publications,[31] the EPA determined that several of the emission sources included in at least one industry segment in subpart W are not currently required to be reported by facilities in all the industry segments in which those sources exist. As such, consistent with section II.A of this preamble, we are proposing to add requirements to report CO_2, CH_4, and nitrous oxide (N_2O) emissions (as applicable for the source type) from the following sources under 40 CFR 98.232 and 98.236(a): [32]

- Onshore petroleum and natural gas production: Blowdown vent stacks
- Onshore natural gas processing: Natural gas pneumatic device venting, Hydrocarbon liquids and produced water storage tank emissions
- Onshore natural gas transmission compression: Dehydrator vents
- Underground natural gas storage: Dehydrator vents, Blowdown vent stacks, Condensate storage tanks
- LNG storage: Blowdown vent stacks, Acid gas removal unit vents
- LNG import and export equipment: Acid gas removal unit vents
- Natural gas distribution: Natural gas pneumatic device venting, Blowdown vent stacks
- Onshore natural gas transmission pipeline: Equipment leaks at transmission company interconnect metering-regulating stations, Equipment leaks at farm tap and/or direct sale metering-regulating stations, Transmission pipeline equipment leaks

We are also proposing several revisions that would facilitate implementation of the proposal to require reporting of these emission sources from additional industry segments. We are proposing to revise the name of the current emission source type ''onshore production and onshore petroleum and natural gas gathering and boosting storage tanks'' to ''hydrocarbon liquids and produced water storage tanks'' and revise ''storage tank vented emissions'' to ''hydrocarbon liquids and produced water storage tank emissions'' throughout subpart W. The proposed removal of the reference to ''onshore production and onshore petroleum and natural gas gathering and boosting'' would reflect a more appropriate name corresponding to the proposed addition of the reporting of these storage tank emissions for the Onshore Natural Gas Processing industry segment; the addition of ''produced water'' to the name is discussed in detail in section III.C.3 of this preamble. Additionally, we are proposing to revise the emission source type name in 40 CFR 98.233(k) and 98.236(k) from ''transmission storage tanks'' to ''condensate storage tanks,'' which would reflect a more appropriate name corresponding to the proposed addition of the reporting of these storage tank emissions for the

[28] *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Systems Industry: Background Technical Support.* November 2010. Docket Id. No. EPA–HQ–OAR–2009–0923–3610; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[29] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020.* U.S. EPA. April 2022. Available at *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[30] *Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry.* Produced by URS Corporation for American Petroleum Institute. November 2021. Available at *https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[31] For example, American Petroleum Institute (API). *Liquefied Natural Gas (LNG) Operations Consistent Methodology for Estimating Greenhouse Gas Emissions.* Prepared for API by The LEVON Group, LLC. Version 1.0, May 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[32] It should be noted that the EPA did not identify any subpart W emission sources missing from the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment.

Underground Natural Gas Storage industry segment.[33]

We are also proposing revisions to the calculation methodologies and/or emissions reporting structure for each of these emission source/industry segment combinations that would be needed in 40 CFR 98.233 and 98.236, respectively. For industry segments for which we are proposing to additionally require reporting of emissions from AGR vents, dehydrator vents, hydrocarbon liquids and produced water storage tank emissions, and condensate storage tank emissions, we are proposing that reporters would use the same calculation methods and report the same information as reporters in the industry segments in which those source types are already reported. For these sources, the EPA is not aware of differences in the operation of the emission sources between industry segments that would necessitate separate calculation methodologies. The remainder of this section describes additional proposed amendments to 40 CFR 98.233.

For the proposed addition of natural gas pneumatic device venting as an emission source for the Onshore Natural Gas Processing industry segment, we are proposing that those facilities would use the proposed calculation methodologies as described in section III.E of this preamble. For any reporters to the Onshore Natural Gas Processing industry segment that would use proposed Calculation Methodology 3, the emission factors we are proposing are the same as the proposed revised emission factors for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments. As noted in the subpart W TSD (available in the docket), the data available to develop emission factors for the Onshore Natural Gas Processing industry segment are limited, and because operations defined as being part of these three industry segments are similar and can occur at the same facilities, the EPA has historically applied the same population and leaker emission factors to these three segments (*e.g.,* equipment leaks). See section III.E of this preamble for additional details about the proposed calculation methodologies.

As noted earlier in this section, we are proposing to add blowdown vent stack reporting to the Onshore Petroleum and Natural Gas Production, Underground Natural Gas Storage, LNG Storage, and Natural Gas Distribution industry segments. Subpart W currently requires reporting of blowdowns either using flow meter measurements (existing 40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (existing 40 CFR 98.233(i)(2)). There are two lists of equipment or event types. One applies to the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, LNG Import and Export Equipment, and Onshore Petroleum and Natural Gas Gathering and Boosting segments (proposed 40 CFR 98.233(i)(2)(iv)(A), as discussed in section III.J.2 of this preamble). The other list of equipment or event types (in proposed 40 CFR 98.233(i)(2)(iv)(B), as discussed in section III.J.2 of this preamble) was developed for the Onshore Natural Gas Transmission Pipeline industry segment when that segment was added to subpart W in 2015 (80 FR 64275, October 22, 2015). To allow reporters in the new industry segments to calculate emissions by equipment or event types, the EPA is proposing to specify the appropriate list of equipment or event types. We are proposing that facilities in the Onshore Petroleum and Natural Gas Production, Underground Natural Gas Storage, and LNG Storage industry segments following the methodology in 40 CFR 98.233(i)(2) would be required to categorize blowdown vent stack emission events into the seven categories provided in proposed 40 CFR 98.233(i)(2)(iv)(A), as the types of blowdown vent stack emission events for these segments are similar to those for the segments currently required to categorize under this provision.

We are proposing that facilities in the Natural Gas Distribution industry segment would be required to categorize blowdowns into the eight categories listed in proposed 40 CFR 98.233(i)(2)(iv)(B), as the types of blowdowns that occur in the Natural Gas Distribution industry segment are expected to be pipeline blowdowns similar to those in the Onshore Natural Gas Transmission Pipeline industry segment. We note that during the early stages of our review of potential new sources, we considered whether to add emissions from mishaps (dig-ins) in the Natural Gas Distribution industry segment as a new emission source. However, mishaps (dig-ins) are already included on the list of equipment and event types in proposed 40 CFR 98.233(i)(2)(iv)(B), specifically emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3. Therefore, a proposed amendment is not necessary to include those events.

We are proposing one other amendment related to the calculation of emissions from blowdown vent stacks. The EPA previously determined that for reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment using the methodology provided in existing 40 CFR 98.233(i)(2) and equation W–14A, it is reasonable to allow engineering estimates based on best available information when determining temperature and pressure for emergency blowdowns, due to the geographically dispersed nature of the facilities in this industry segment. As discussed in section III.J.3 of this preamble, we are proposing to also allow engineering estimates based on best available information when determining temperature and pressure for emergency blowdowns for the Onshore Natural Gas Transmission Pipeline industry segment, as facilities in this industry segment are also geographically dispersed. Due to the fact that facilities in the Onshore Petroleum and Natural Gas Production and Natural Gas Distribution industry segments are similarly geographically dispersed, we are proposing that reporters in those industry segments using the methodology provided in 40 CFR 98.233(i)(2) and equation W–14A would also be allowed to use engineering estimates based on best available information available when determining temperature and pressure for emergency blowdowns.

For the Onshore Natural Gas Transmission Pipeline industry segment, as noted earlier in this section, we are proposing to add reporting of emissions from equipment leaks from transmission pipelines, transmission company interconnect metering-regulating stations, and farm tap and/or direct sale stations. The EPA proposes to add these sources to the calculation methodologies provided in 40 CFR 98.233(r), with associated proposed updates to the variable definitions in equation W–32A to include components in the Onshore Natural Gas Transmission Pipeline industry segment. We are also proposing to add default CH4 population emission factors for the components specified in this paragraph at facilities in the Onshore Natural Gas Transmission Pipeline industry segment in proposed Table W–5 of subpart W. The EPA derived these proposed emission factors from the 1996 Gas Research Institute (GRI)/EPA study *Methane Emissions from the Natural Gas Industry* (hereafter referred to as ''the 1996 GRI/EPA study''), specifically

[33] Revisions are also proposed to 40 CFR 98.232(e)(3) to reference the source as ''condensate storage tanks.''

Volumes 9 and 10.[34] The precise derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. We are proposing that emissions from these components would be reported using population emission factors, as we are not aware of any currently available information or data that could be used to develop leaker emission factors from transmission pipelines, transmission company interconnect metering-regulating stations, or farm tap and/or direct sale stations. We are seeking comments on whether there are study data available which could be used to develop default leaker factors whereby subpart W could include the use of equipment leak surveys, default component-specific leaker emission factors, and the calculation method in 40 CFR 98.233(q) an as option for transmission pipeline facilities to quantify emissions from transmission company interconnect metering-regulating stations, or farm tap and/or direct sale stations. Similarly, we are seeking comment on whether an option to survey components at transmission company interconnect metering-regulating stations, or farm tap and/or direct sale stations using the existing methods in subpart W in 40 CFR 98.234 (*e.g.,* EPA Method 21, optical gas imaging (OGI)) and directly measuring and reporting emissions consistent with proposed 40 CFR 98.233(q)(3) should be provided; or whether a methodology in which a multi-year leak survey cycle and the application of either default emission factors or measurements used with the methods provided in 40 CFR 98.233(q) should be provided analogous to the methodology provided for above grade transmission-distribution transfer stations should be provided. We are specifically interested in comments on which approach would be preferred and the supporting rationale.

Separately, concerning the quantification of emissions from transmission pipelines, we are seeking comments on alternative methods for surveying for equipment leaks as well as quantifying and reporting emissions from these emission sources. We are specifically interested in what survey techniques would be appropriate and why, including supporting information on specific instruments and their detection capabilities and whether certain methods would be more suitable for the survey of pipeline leaks than others. We are also seeking comment on what quantification techniques would be best suited for measuring emissions from pipeline leaks and whether these techniques require digging down to the pipeline in order to quantify emissions and also verify pipeline characteristics. As an example, the EPA performed a review of recent study data (Weller et al. 2020) that used an alternative technology, namely AMLD, for the purposes of performing surveys to identify leaks and as a method to quantify emissions from pipeline leaks. For the reasons discussed in section III.Q.2 of this preamble and discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234, we are not proposing amendments based on that study or use of that technology. Instead, we are seeking comment on the scope and frequency of leak detection surveys and measurements for transmission pipelines. We are considering whether we should require annual surveys of the entire pipeline system or whether a reduced frequency of survey (*i.e.,* partial surveys over a multi-year survey cycle in which the entire system is surveyed during the survey cycle and approximately equal portions of the system are surveyed each year of the multi-year survey cycle) is more appropriate and why. Finally, we are seeking comment on whether facilities should be permitted to develop facility-specific pipeline emission factors based on direct measurements and if so, what the appropriate number of measurements should be for determining a representative emission factor for each pipeline material including supporting rationale.

2. Nitrogen Removal Units

The EPA is proposing to revise existing 40 CFR 98.232, 98.233(d), and 98.236(d) to add calculation and reporting requirements for CH_4 emissions from nitrogen removal units used in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Petroleum Natural Gas Gathering and Boosting, LNG Storage, and LNG Import and Export Equipment industry segments. Nitrogen removal units remove nitrogen from the raw natural gas stream to meet pipeline requirements and for compressing natural gas into LNG.[35] [36] The nitrogen removal unit typically follows in series after other process units that remove acid gas (e.g., CO2, hydrogen sulfide), water, and heavy hydrocarbons. It is estimated that 11 percent of current daily production and 16 percent of known gas reserves in the U.S. contain some nitrogen.[37] Methane emissions from nitrogen removal units occur from the vent and as fugitives. A nitrogen removal unit separates the nitrogen gas from the CH_4 resulting in an outlet CH4 stream that contains approximately 2 to 5 percent nitrogen[38] and an outlet nitrogen stream that can contain 1 to 5 percent CH_4 (EPA 2005).[39] Optimization of the nitrogen removal unit can reduce CH_4 in the outlet nitrogen stream to 2 percent (EPA 2005) and even to 1 percent CH_4 by volume.[40] The EPA GasSTAR program already accounts for CH_4 emissions from nitrogen removal unit vents and fugitives.

Based upon a 2002 field study conducted at four natural gas processing plants,[41] the EPA estimates that emissions from nitrogen removal unit vents that would be reported to the GHGRP would be approximately 2,400 mt CH_4 per year. For more information on the estimation of potential CH_4 emissions from nitrogen removal unit venting see the subpart W TSD, available in the docket for this

[34] *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report* (GRI–94/0257.26 and EPA–600/R–96–080i) and *Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution, Final Report* (GRI–94/0257.27 and EPA–600/R–96–080j). Gas Research Institute and U.S. Environmental Protection Agency. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[35] Kuo, J.C., K.H. Wang, C. Chen. Pros and cons of different Nitrogen Removal Unit (NRU) technology. 7 (2012) 52–59. *Journal of Natural Gas Science and Engineering.* July 2012. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[36] Park, J., D. Cho. Decision methodology for nitrogen removal process in the LNG plant using analytic hierarchy process. *Journal of Industrial and Engineering Chemistry.* 37 (2016) 75–83. 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[37] Kuo 2012.

[38] Weidert, D.J., and R.B. Hopewell. Holding the Key. *Hydrocarbon Engineering.* August 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[39] EPA 2005. *Optimizing Nitrogen Rejection Units, Lessons Learned from Natural Gas STAR.* Gas Processors Association, Devon Energy, Enogex, Dynegy Midstream Services, and EPA's Natural Gas STAR Program. Presented at Processors Technology Transfer Workshop. April 22, 2005. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[40] *Nitrogen Rejection Unit Optimization, PRO Fact Sheet No. 905.* U.S. Environmental Protection Agency, Partner Reported Opportunities (PROs) for Reducing Methane Emissions. 2011. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[41] *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants.* Prepared for Gas Technology Institute under U.S. EPA Grant No. 827754–01–0. Clearstone Engineering. June 20, 2002. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

The EPA is proposing to define ''nitrogen removal unit'' in 40 CFR 98.238 as a process unit that separates nitrogen from natural gas using various separation processes (e.g., cryogenic units, membrane units) and ''nitrogen removal unit vent emissions'' as the nitrogen gas separated from the natural gas and released with CH_4 and other gases to the atmosphere, flare, or other combustion unit. The EPA is proposing to amend 40 CFR 98.232(c)(17), 98.232(d)(5), 98.232(g)(10), 98.232(h)(9), and 98.232(j)(3) to add nitrogen removal unit vents to the list of source types for which the industry segments previously specified would be required to report emissions. Corresponding additions are proposed at 40 CFR 98.236(a) to add nitrogen removal units to the list of equipment and activities that would be reported for each of these industry segments.

The EPA is proposing CH_4 emission calculation methodologies for nitrogen removal units that are identical to the existing calculation methodologies in 40 CFR 98.233(d) for AGRs (which currently apply to calculating emissions of CO_2). These methods include use of vent meters, engineering calculations based upon flowrate of gas streams, or calculation using simulation software. Further, the EPA is proposing to add relevant reporting elements for CH_4 emissions from nitrogen removal units to 40 CFR 98.236(d) for each of the proposed allowable calculation methodologies. As a part of this proposed rulemaking, the EPA is also proposing to require the reporting of CH_4 emissions from AGR vents. Refer to section III.F.1 of this preamble for more detailed discussion of the calculation methodologies, including additional revisions proposed as part of this rulemaking and which we propose would also apply to nitrogen removal units.

The EPA is proposing that nitrogen removal unit vents routed to a flare would follow the same calculation requirements as other flared emission source types in proposed 40 CFR 98.233(n) and that flared nitrogen removal unit emissions (CO_2, CH_4, and N_2O) would be reported under proposed 40 CFR 98.236(n) separately from vented nitrogen removal unit emissions (CH_4). The flared nitrogen removal unit emissions would be included with ''other'' flared source types for purposes of the proposed disaggregation provisions in proposed 40 CFR 98.233(n)(10) and proposed 40 CFR 98.236(n)(19). See section III.N of this preamble for more information on the proposed flaring calculation and reporting provisions.

The EPA is seeking comment on the proposal to require reporting of CH_4 emissions from nitrogen removal unit venting, including the estimated magnitude of emissions, which industry segments, if any, should be required to report nitrogen removal unit vent emissions, and whether the existing calculation methods for AGR vents are appropriate and if there are other methods the EPA should consider.

3. Produced Water Tanks

The EPA is proposing to add CH_4 emissions from produced water tanks to subpart W. The EPA is proposing to define ''produced water'' consistent with the definition in the effluent guidelines for the oil and gas extraction point source category (40 CFR 435.11(bb)), which is the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process. Produced water is the largest wastewater source by volume generated during oil and gas extraction.[42] The ratio of produced water to recovered hydrocarbon is extremely variable across the U.S., ranging from less than 1:1 to more than 100:1.[43] In the 2022 U.S. GHG Inventory emissions estimate for 2020, the EPA estimated approximately 140,300 mt CH_4 emissions from produced water tanks associated with natural gas wells and 88,600 mt CH_4 emissions from produced water tanks associated with oil wells.

The EPA is proposing amendments to 40 CFR 98.233(j) to require reporters with atmospheric pressure storage tanks receiving produced water to calculate CH_4 emissions using any of the three calculation methodologies specified in 40 CFR 98.233(j)(1) through (3).[44] For facilities with produced water storage tanks electing to model their CH_4 emissions consistent with 40 CFR 98.233(j)(1), the EPA is proposing to allow facilities to select any software option that meets the requirements currently stated in 40 CFR 98.233(j)(1) (i.e., to select a modeling software that uses the Peng-Robinson equation of state, models flashing emissions from produced water, and speciates CH_4 emissions that result when the produced water from the separator or non-separator equipment enters an atmospheric pressure storage tank), but we request comment on whether the Peng-Robinson equation of state should be used for produced water tanks and whether there are other parameters that should be considered requirements for modeling emissions from produced water tanks. We expect that modeling flashing emissions from produced water tanks would calculate accurate estimates of CH_4 emissions, as it is widely accepted that these models provide accurate estimates of flashing emissions from hydrocarbon liquids atmospheric storage tanks. Therefore, we expect process simulation software options such as Bryan Research & Engineering (BRE)'s ProMax®[45] (ProMax) would be appropriate for modeling produced water CH_4 emissions. For example, BRE has produced a white paper regarding ProMax's accuracy in predicting produced water emissions.[46] However, per the 2021 API Compendium, the EPA is aware that API 4697 E&P Tanks v3.0 program[47] is not appropriate for determining emissions from produced water tanks, as the program's methodology is based on properties specific to crude oil. Given that API's E&P Tanks software cannot model produced water tanks, we are proposing to specifically state in 40 CFR 98.233(j)(1) that API's E&P Tanks should only be used for modeling atmospheric storage tanks receiving hydrocarbon liquids.

There are several documents that address produced water emissions; however, the emission factors used in all of these documents all ultimately trace back to the 1996 GRI/EPA study.[48]

[42] Summary of Input on Oil and Gas Extraction Wastewater Management Practices Under the Clean Water Act. Final Report. EPA–821–S19–001. U.S. Environmental Protection Agency, Engineering and Analysis Division, Office of Water. Washington, DC May 2020.

[43] *Ibid.*

[44] As part of the proposed amendment to require reporters to calculate and report emissions from produced water tanks, we are also proposing conforming edits throughout subpart W to refer to hydrocarbon liquids and produced water instead of just hydrocarbon liquids.

[45] BRE Promax® software available from BRE website (*https://www.bre.com/*).

[46] *Are Produced Water Emission Factors Accurate?* Bryan Research & Engineering, Inc. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[47] E&P Tanks v3.0 software and the user guide (Publication 4697) formerly available from the API website.

[48] Studies referencing the 1996 GRI/EPA study produced water emission factors include: (1) 2021 API Compendium; (2) *Oil & Gas Production Protocol, Annex II to the General Reporting Protocol*, Version 1.0. The Climate Registry. February 2010; (3) *2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States.* Produced by ENVIRON International Corporation and Eastern Research Group, Inc. (ERG) for Central States Air Resources Agencies (CenSARA). December 2012; and (4) *Instructions for Using the 2017 EPA Nonpoint Oil and Gas*

Therefore, the EPA is proposing to add CH_4 emission factors to 40 CFR 98.233(j)(3) that were developed as part of the 1996 GRI/EPA study,[49] which is consistent with the factors used by the U.S. GHG Inventory.[50] The emission estimates from the 1996 GRI/EPA study were estimated using an ASPEN PLUS process simulation assuming the natural gas industry produces 497 million barrels of salt water annually, including approximately 100 million barrels from coal bed CH_4 wells; 70 percent of the water from gas wells is reinjected with the remaining 30 percent stored in atmospheric tanks; and hydrocarbon composition is 100 percent CH_4.[51] The 1996 GRI/EPA study estimated produced water emissions for salt contents of 2, 10, and 20 percent, and pressures of 50, 250, and 1,000 pounds per square inch. The 2021 API Compendium (Table 6–26) provides the 1996 GRI/EPA emission factors converted from units of million pounds per year to units of metric tons per thousand barrels (based upon the assumption of 497 million barrels of produced water annual production). In addition, average emission factors were calculated for each pressure.

We also propose to add reporting requirements for produced water tanks. The provisions in 40 CFR 98.236(j)(1) are proposed to be revised to refer to both hydrocarbon liquid and produced water atmospheric storage tanks. Additionally, we are proposing to add reporting requirements to 40 CFR 98.236(j)(2) for total annual produced water volumes for each pressure range, estimates of the fraction of produced water throughput that is controlled by flares and/or vapor recovery, counts of controlled and uncontrolled produced water tanks, and annual CH_4 emissions vented directly to atmosphere from produced water tanks. Flared produced water tank emissions would be reported under 40 CFR 98.236(n), as proposed in section III.N.2 of this preamble. Industry segments required to report emissions from produced water tanks would include Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Processing. The EPA is also proposing to revise the emission source type name in 40 CFR 98.233(j) and 40 CFR 98.236(j) from ''onshore production and onshore petroleum and natural gas gathering and boosting storage tanks'' to ''hydrocarbon liquids and produced water storage tanks'' to reflect the proposed addition of produced water tanks. The EPA is also proposing to revise the source type provided in 40 CFR 98.232(c)(10) and 40 CFR 98.232(j)(6) to ''Hydrocarbon liquid and produced water storage tank emissions'' which reflects the addition of produced water tanks.

4. Mud Degassing

The EPA is proposing to add a new emission source type to subpart W for emissions from drilling mud degassing. The proposed amendments for this new source type would add calculation and reporting requirements for CH_4 emissions from mud degassing associated with well drilling for onshore petroleum and natural gas production facilities in 40 CFR 98.232(c), 98.233(dd), and 98.236(dd). In this proposal, the EPA is not proposing to require the reporting of CO_2 emissions from this source. Based on available research, it appears that CH_4 is the primary GHG emitted from this source, while emissions of CO_2 are expected to be very small. However, as noted later in this section, the EPA is seeking comment on requiring reporting of CO_2 emissions from mud degassing, including comment on the expected magnitude of CO_2 emissions from mud degassing and appropriate calculation methods for CO_2 emissions from mud degassing.

The term ''drilling mud,'' also referred to as ''drilling fluid,'' refers to a class of viscous fluids used during the drilling of oil and gas wells. Throughout the drilling process, drilling mud is pumped continuously through the drill string and out the bit to cool and lubricate the drill bit, carry cuttings away from the drill bit, and to maintain the desired pressure within the well. The three types of drilling mud used in the oil and gas industry are water-based, oil-based, and synthetic-based muds. The density of the mud can be controlled to counteract formation pressure, and drilling mud adds stability to the bore hole. During drilling, gas is freed from rock drilled out of the wellbore and becomes entrained in the drilling mud that is being pumped continuously through the drill string.

As drilling mud circulates through the wellbore, natural gas and heavier hydrocarbons can become entrained in the mud. Mud degassing refers to the practice of extracting the entrained gas from drilling mud once it is outside the wellbore. Gas entrained in the drilling mud is separated from the mud in a mud separator and then vented directly to the atmosphere or flared. The entrained gas contains CH_4 and can contain other pollutants such as volatile organic compounds (VOC) and possibly CO_2, depending on the gas characteristics of the hydrocarbon-bearing zones through which the borehole is drilled, including the target zone. Although the majority of natural gas will be released when the mud passes through the mud separator, small quantities of natural gas will remain entrained in the drilling mud and in the rock cuttings after the mud passes through the traps. These small quantities will eventually be released to the atmosphere as the drilling mud and associated cuttings are stored, processed and disposed.

Based on our review of the available information regarding mud degassing emissions, we note that mud degassing has been included only in a limited number of U.S. state-level, regional and national inventories of the onshore oil and gas production segments, mostly due to a lack of sufficient data to characterize the emissions. In a 1977 EPA publication titled, *Atmospheric Emissions from Offshore Oil and Gas Development and Production*,[52] the EPA estimated two total hydrocarbon (THC) emission factors in units of emissions per drilling day, one for water-based mud degassing and the other for oil-based mud degassing, based on engineering calculations. The 1977 EPA publication does not include emission factors for synthetic-based mud. Several entities, such as the state of New York and the Central States Air Resources Agency (CenSARA), have incorporated estimates for mud degassing in their inventory estimates. A CenSARA study conducted in 2011 developed default emission factors derived from the 1977 EPA report.[53] The CenSARA study

Emissions Estimation Tool, Production Module. Produced by Eastern Research Group, Inc. (ERG) for U.S. Environmental Protection Agency. October 2019.

[49] *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary, Final Report.* GRI–94/0257.23 and EPA–600/R–96–080f. Gas Research Institute and U.S. Environmental Protection Agency. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[50] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2019: Updates for Produced Water Emissions.* April 2021. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[51] *Atlas of Gas Related Produced Water for 1990.* 95/0016. Produced by Energy Environmental Research Center, University of North Dakota, and ENSR Consulting and Engineering for Gas Research Institute. May 1995. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[52] *Atmospheric Emissions from Offshore Oil and Gas Development and Production.* Produced by Energy Resources Co. for Environmental Protection Agency. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[53] *2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States.* Produced by ENVIRON International Corporation

Continued

added a THC emission factor for synthetic drilling muds and also provided emission factors in mt CH_4 per drilling day. The THC emission factors are 881.84 pounds per drilling day for water-based muds and 198.41 pounds per drilling day for oil-based and synthetic drilling muds. The CH_4-specific emission factors are 0.2605 mt CH_4 per drilling day for water-based muds and 0.0586 mt per drilling day for oil-based and synthetic drilling muds; they are based on an assumption of 83.85 percent CH_4 in the gas stream vented from mud degassing. The CenSARA methodology does allow for adjustment of the CH_4 default emission factors to local conditions by multiplying the nationwide emission factor to the ratio of the local CH_4 mole percent of vented gas to the mole percent of CH_4 from the vented gas used to derive the CenSARA emission factor (83.85).

For its emissions inventory, the state of New York based its emission factor for mud degassing on the CenSARA study, while also concluding that communication with experts indicated that there were not any more recent estimates available.[54] Furthermore, New York only adopted the CenSARA CH_4 emission factor of 0.2605 mt CH_4 per drilling day for water-based muds. This factor serves as the single emission factor for New York. Unlike CenSARA, New York's calculation methods do not provide the ability for users to make a local adjustment to the emission factor. Both CenSARA and New York define the number of drilling days as the completion date minus the spud date.

The U.S. GHG Inventory does not currently include mud degassing emissions. In 2020, the EPA released a memorandum discussing the potential inclusion of CH_4 emissions estimates for mud degassing as an update under consideration for the U.S. GHG Inventory, based on the THC emission factors presented in the 1977 EPA publication.[55] Specifically, the memorandum provided emission factors of 0.32 mt CH_4 per drilling day for water-based drilling muds and 0.07 mt CH_4 per drilling day for oil-based drilling muds in the discussion. The CH4 emission factor presented for consideration for updating the U.S. GHG Inventory assumed a default CH_4 fraction (by weight) of 61.2 percent for associated gas. The EPA has not to date incorporated the use of these emission factors, and mud degassing is not included in the current U.S. GHG Inventory.

Separately, API published updated CH_4 and whole gas emission factors based on the emission factors from the 1977 EPA publication in their 2021 API Compendium.[56] API's updated CH_4 emission factors are based on a gas content of 65.13 weight percent CH_4, derived from sample data provided in the 1977 EPA publication. While including the same THC and CH_4 emission factors as CenSARA, API specifies that these are for offshore drilling only. The API Compendium presents lower emission factors for onshore drilling. In the 2021 API Compendium, API stated that it adjusted the 1977 EPA values for borehole size and porosity to better reflect those used in onshore drilling. API's onshore production CH_4 emission factors are 0.0458 mt per drilling day for water-based mud and 0.0103 mt per drilling day for oil-based and synthetic muds. Similar to CenSARA, the API methodology allows for the nationwide emission factors to be adjusted to local conditions by applying a ratio of the mole percent in vented gas from degassing at local operations to the nationwide mole percent of 83.85.

Although most efforts have focused on the development of emission factors for mud degassing, the 2021 API Compendium also encourages operators to use site-specific CH_4 (and CO_2 if present) measurements to estimate emissions if possible. Generally, measured data would involve use of mud-logger services with hydrocarbon gas sensors. In some cases, operators may use gas chromatography, but gas chromatography alone does not allow calculation of gas concentration in the mud. Gas emissions would be determined by using the volumetric flowrate of the mud, the amount of time of mud flow and the concentration of CH_4 and CO_2 in the mud.

After careful consideration of the available literature and well drilling and mud degassing practices, the EPA is proposing two options in a new paragraph (40 CFR 98.233(dd)) to measure CH_4 emissions from drilling mud degassing: use of measurements taken through mudlogging and gas detection at representative wells and use of emission factors and activity counts.

Calculation Method 1 would require the reporter to calculate CH_4 emissions from mud degassing for a representative well. To qualify as a representative well, the well would be required to be drilled in the same sub-basin and at the same targeted total depth from the surface as the wells it is representative of. Calculation Method 1 would be required to be used when the reporter has taken mudlogging measurements, including gas trap-derived gas concentration and mud pumping rate, for at least one well in the sub-basin at the approximate total depth. A CH_4 emissions rate from mud degassing would be calculated for the representative well and the CH_4 emission rate for the well would be applied to the total time drilling mud is circulated through the wellbore during drilling for each of the other wells drilled in the same sub-basin and targeting the same approximate total depth from surface in the reporting year.

The operator would be required to identify and calculate natural gas emissions for a new representative well at least once every 2 years for each sub-basin and targeted depth within the facility to ensure that the emissions from representative wells are representative of the operating and drilling practices within each applicable sub-basin in the facility. In the Onshore Petroleum and Natural Gas Production industry segment, facilities are defined at the basin-level. In the first year of reporting, however, the operator may use measurements from the prior reporting year if measurements from the current reporting year are not available.

Proposed Calculation Method 1 uses a three-step approach to calculate emissions from mud degassing for each well in a particular sub-basin and at the same approximate total targeted depth. In the first step, reporters would calculate CH_4 emissions for the representative well using proposed equation W–41. For this step, the reporter would need to know the average efflux mud rate from the mud pump in gallons per minute (gpm),

for Central States Air Resources Agencies. November 2011. Available at *https://www.deq.ok.gov/wp-content/uploads/air-division/EI_OG_Final_Report_CenSara_122712.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[54] *New York State Oil and Gas Sector: Methane Emissions Inventory.* Produced by Abt Associates for New York State Energy Research and Development Authority. November 2022. Available at *https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/22-38-New-York-State-Oil-and-Gas-Sector-Methane-Report-acc.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[55] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2019: Update under Consideration for Mud Degassing Emissions.* September 2020. Available at *https://www.epa.gov/sites/default/files/2020-09/documents/ghgi-webinar2020-degassing.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[56] *Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry.* Produced by URS Corporation for American Petroleum Institute. November 2021. Available at *https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

''MR_r''; the total amount of time in minutes that drilling mud is circulated in the representative well, ''T_r''; the percentage of the fluid flow that is gas, ''X_n''; and the measured mole concentration of CH_4, ''GHG_{CH4}.'' If a representative well cannot be identified because mudlogging was not used for any well within the same sub-basin and at the same targeted approximate total depth, the reporter may choose a representative well within the facility that is drilled into the same formation and at the same approximate total depth.

In the second step, reporters would calculate the CH_4 emissions rate for the representative well using proposed equation W–42. The emissions rate would be derived by dividing the representative well's total annual CH_4 emissions, ''$E_{s,CH4,r}$,'' by the total time that drilling mud is circulated in the representative well, ''T_r.'' In the third step, reporters would apply the CH_4 emissions rate calculated in the second step to other wells in the sub-basin that are at the same approximate total depth to derive the total volume of CH_4 emissions for each well at that depth. In this step, the reporter would calculate total CH_4 emissions for each well, ''p,'' in the same sub-basin and at the same approximate total depth as the representative well using proposed equation W–43, where the total time drilling mud is circulated in the well would be multiplied by the representative well's emissions rate, ''$ER_{s,CH4,p}$,'' determined using equation W–42 in step 2.

If mudlogging measurements were not taken, the EPA is proposing that reporters would use Calculation Method 2 and determine emissions from mud degassing using proposed equation W–44, which incorporates the nationwide emission factors provided by the CenSARA study. Specifically, the EPA is proposing an emission factor of 0.2605 mt CH_4 per drilling day per well for water-based mud and a factor of 0.0586 mt CH_4 per drilling day per well for oil-based and synthetic drilling muds. As noted by New York state, there are limited data and few studies on mud degassing emissions. The EPA is proposing these emission factors as an alternative calculation method because our assessment of the available literature is that these proposed emission factors are generally appropriate if measurements are not available. In addition, the emission factors proposed are consistent with those of several organizations that calculate and publish emissions from mud degassing in their inventories. As noted previously in this section, these factors are based on a CH_4 mole percent of 83.85 in the gas stream vented from mud degassing. The EPA is not proposing to allow adjustment of the emission factors for local conditions under proposed Calculation Method 2 because the use of emission factors under this proposed calculation method would only be allowed if the operator did not have site-specific measurements (*i.e.,* would not have the measurement that would be the basis of such an adjustment).

Although the EPA is proposing to use the nationwide emission factors provided by the CenSARA study, the EPA is proposing to define the number of drilling days differently than the study. Rather than considering the first drilling day to be the day the well is spudded, we are proposing that the total number of drilling days is the sum of all days from the first day that the borehole penetrates the first hydrocarbon-bearing zone through the completion of all drilling activity. The EPA believes that penetration of the first hydrocarbon-bearing zone more accurately reflects the point in time where CH_4 will start becoming entrained in drilling mud. The EPA is also defining the last drilling day as the day drilling mud ceases to be circulated in the well. Reporters would calculate emissions for each well by multiplying the emission factor by the number of drilling days per well per year.

The EPA is seeking comment on these calculation methodologies, including whether there are calculation methodologies other than the proposed methods that the EPA should consider for calculating CH_4 emissions from mud degassing. The EPA is also seeking comment on CO_2 emissions from mud degassing, including the magnitude of CO_2 emissions from this source type, whether emissions of CO_2 should be reported, and suggested calculation methods for CO_2 emissions. The EPA is also seeking comment on whether to consider mud weight balance in the derivation of emission factors, and if so, how to incorporate such considerations. Underbalanced, balanced, and overbalanced all lead to varying hydrostatic weights of the mud and could affect the flow of hydrocarbons into the well bore, possibly impacting emissions calculations. However, we are not aware of any studies to date that have considered mud weight balance.

In addition to the calculation requirements, the EPA is proposing corresponding reporting requirements for emissions by well in 40 CFR 98.236(dd). Specifically, for all wells with mud degassing emissions that use Calculation Method 1, the reporter would report the well ID number for each well for which mud degassing emissions are calculated, the approximate total depth of the well in feet below surface, and the total time in minutes that drilling mud is circulated in the well. Reporters would also report whether the drilling mud used was water-based, oil-based, or synthetic. Additionally, for a well that is not a representative well, reporters would report the well ID number of the representative well that was used to derive the CH_4 emissions rate used to calculate emissions from the non-representative well.

For reporters using Calculation Method 1, the EPA is also proposing to require additional data on representative wells, including the average mud flow rate in gpm, the concentration of natural gas in the drilling mud, the measured mole fraction of CH_4 in the drilling mud, and the CH_4 emissions rate. For reporters using Calculation Method 2, the EPA is proposing that reporters would report the well ID number for each well for which mud degassing emissions are calculated, the total number of drilling days at each well, and whether the drilling mud used was water-based, oil-based, or synthetic. Annual CH_4 emissions in mt CH_4 would be reported for each well whether emissions were calculated using Calculation Method 1 or Calculation Method 2.

To clearly define the emission source type and parameters to use in the emissions calculations, the EPA is proposing to define three new terms in 40 CFR 98.238. The EPA is proposing to define ''drilling mud'' as a mixture of clays and additives with water, oil, or synthetic materials continuously pumped through the drill string and out the bit while drilling to cool and lubricate the drill bit and to move cuttings through the wellbore to the surface. The EPA is proposing to define ''drilling mud degassing'' as the practice of safely removing pockets of free gas entrained in the drilling mud once it is outside of the wellbore. ''Mud rate'' is proposed to mean the pumping rate of the mud by the mud pumps, usually measured in gpm. The mud rate would be an input to proposed equation W–41.

Finally, we note that in proposing these new requirements, we considered adding mud degassing emissions to two existing source categories in the Onshore Petroleum and Natural Gas Production industry segment, well completions and workovers with hydraulic fracturing and well completions and workover without hydraulic fracturing, rather than proposing calculation and reporting requirements for mud degassing as a new emissions source. Upstream oil and gas development is undertaken in two stages, exploration and production. The exploration stage consists of well drilling followed by well completion, including casing of the well and hydraulically fracturing the well (in the case of hydraulically fractured completion). However, for purposes of this proposal, the EPA has determined that well drilling activities are a distinct activity separate from well completion. For example, a common practice in the oil and gas industry is to drill a well but leave the borehole uncompleted (referred to in the oil and gas industry as ''drilled but uncompleted''). These boreholes are left uncompleted for a period of time until economic conditions improve, completion crews are available, or for other reasons. Even without completion, the drilling activity still has the potential to produce emissions. Therefore, the EPA is proposing drilling mud degassing as a new emissions source type source for onshore petroleum and natural gas production facilities.

5. Crankcase Venting

The EPA is proposing to add calculation and reporting requirements for CH_4 emissions from a new emission source type, crankcase ventilation from RICE or GT used in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, Natural Gas Distribution, and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. Crankcase ventilation is the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine.[57] This proposed source does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process.[58]

The EPA first proposed including ''crankcase vents'' in subpart W in the January 2016 proposal to add leaker emission factors (81 FR 4987, January 29, 2016). At that time in 2016, the EPA proposed to add new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the leak detection methods in the then proposed NSPS OOOOa (80 FR 56593, September 18, 2015). Specifically, in 2016, the EPA proposed aligning subpart W equipment components with the 2015 proposed NSPS OOOOa definition of ''fugitive emissions component,'' which was ''any component that has the potential to emit fugitive emissions of [CH_4] or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters'' (80 FR 56593, September 18, 2015). The proposed NSPS OOOOa definition of ''fugitive emissions component'' also indicated that it did not include devices that ''vent as part of normal operations.'' Commenters on the proposed NSPS OOOOa indicated that some of the examples listed within the proposed definition of ''fugitive emissions component'' did include devices that vent as part of normal operations, including crankcase vents.[59] As a result of these comments, the final definition for ''fugitive emissions component'' in the NSPS OOOOa (81 FR 35824, June 3, 2016) did not include the reference to ''crankcase vents'' or other types of devices that vent as part of normal operations, consistent with the EPA's stated intent in the 2015 NSPS OOOOa proposal not to include those devices in the definition. The 2016 promulgated amendments to subpart W for fugitive emissions aligned with the definition of ''fugitive emissions component'' in the final NSPS OOOOa.

We have estimated sector-wide emissions from crankcase ventilation using data from a 2015 study published by Johnson *et al.*, *Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities*.[60] In this study, the audit of three natural gas compressor stations and two natural gas storage facilities yielded an average ratio of crankcase-to-exhaust emissions of 14.4 percent. The study authors compared total emissions rate (crankcase plus exhaust) against literature values of a four-cylinder lean burning engine in EPA's *Compilation of Air Pollutant Emission Factors* (AP–42).[61] The literature value overpredicted the combined emissions by 11.4 percent, which slightly exceeded the calculated uncertainty for exhaust emissions of 7.2 percent. This comparison indicates the measured value offers a reasonable estimate of CH_4 loss from natural gas compressor stations and storage facilities. Based on this study, the EPA conservatively estimates that the total CH_4 emissions from crankcase ventilation that could be reported to the GHGRP would be approximately 800,000 mt per year, assuming crankcase emissions are 14.4 percent of combustion emissions from all proposed industry segments. For more information on the estimation of potential CH_4 emissions from crankcase venting, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

The API provided an emission factor for CH_4 from crankcase ventilation in their 2021 API Compendium.[62] API's emission factor was developed from results from Phase II of a comprehensive measurement program conducted to determine cost-effective directed inspection and maintenance control opportunities for reducing natural gas losses due to fugitive equipment leaks and avoidable process inefficiencies. Phase II of the program was conducted at five gas processing plants, seven gathering compressor stations, and twelve well sites during 2004 and 2005.[63]

[57] Cox, J. ''Managing Engine Blow-by with Crankcase Ventilation Systems.'' *The Solberg Blog*, June 17, 2022. Available at *https://www.solbergmfg.com/en/resources/blog/crankcase-ventilation-system-for-engine-in-the-pow* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[58] See, *e.g.*, Caterpillar. Application & Installation Guide: Crankcase Ventilation Systems. LEBW4958–04. 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[59] U.S. EPA. *EPA's Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*. Chapter 4—Fugitives Monitoring. May 2016. Available as EPA–HQ–OAR–2010–0505–7632 and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[60] Johnson, D.R., *et al.* 2015. ''Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities.'' *Environ. Sci. Technol.* 2015, 49, 13, 8132–8138. July 4, 2015. Available at *https://doi.org/10.1021/es506163m* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[61] U.S. EPA. *AP–42 Compilation of Air Pollutant Emission Factors*, 5th ed. Volume I, Chapter 3: Stationary Internal Combustion Sources: Section 3.1 Stationary Gas Turbines and Section 3.2 Natural Gas-fired Reciprocating Engines. Available at *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-3-stationary-0* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[62] *Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry*. Produced by URS Corporation for American Petroleum Institute. November 2021. Available at *https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[63] *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas*

Based on the information provided in this section, the EPA is proposing to add 40 CFR 98.233(ee) to provide a component-level average emission factor approach for estimating emissions for crankcase ventilation based on the number of crankcase vents on RICE or GT in the facility. The proposed CH_4 emission factor for crankcase ventilation is 2.28 standard cubic feet per hour per source, as provided in the 2021 API Compendium. The 2021 API Compendium emission factor was selected as representative because it was developed from results of the most comprehensive field study of crankcase ventilation in the oil and natural sector available to date. Site-specific information required for the emission calculation would include the number of crankcase vents on RICE or GT, the operating time of each engine or GT, and the concentration of CH_4 in the gas stream entering the engines or GT. If site-specific CH_4 concentration is unknown, the proposed provision includes an option to determine the CH_4 concentration in the gas stream using either engineering estimates based on best available data or the provisions of 40 CFR 98.233(u)(2). The EPA is seeking comment on whether this calculation method is appropriate and whether there are other methodologies that we should consider providing, including details on how those additional methods would be applied to this source. For reporting, the EPA is proposing to add 40 CFR 98.236(ee) to require reporters to provide emissions, the number of crankcase vents at the facility, and engine or GT operating hours.

D. Reporting for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Industry Segments

Within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source. Examples of emission sources that report at the sub-basin or county level include liquids unloading, completions and workovers with hydraulic fracturing, and storage tanks. Sources that report at the facility (basin) level include natural gas pneumatic devices, blowdown vent stacks, and equipment leaks. The current aggregation of data reported within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency.

In order to address these concerns and improve data quality consistent with section II.C of this preamble, the EPA is proposing to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. As a first step, the EPA is proposing to revise the reporting requirements to be more explicitly consistent with the current reporting form structure for the well identification (ID) numbers at the facility, with two proposed changes and one addition. Currently, for certain emission sources directly related to wells (liquids unloading, completions and workovers with hydraulic fracturing, completions and workovers without hydraulic fracturing well testing, and associated natural gas), subpart W requires reporters to provide a list of well ID numbers in each sub-basin that contributed to the emissions (*e.g.*, a list of well IDs that had completions or workovers with hydraulic fracturing). Under existing 40 CFR 98.236(aa)(1)(ii)(D) through (H), reporters are also asked to provide the counts of wells that were producing, acquired, divested, completed, and/or permanently taken out of production for each sub-basin, along with a list of well ID number for the wells in each of those categories. For the subpart W reporting form, these requirements were implemented through addition of a single table, in which reporters provide a list of all well ID numbers, the sub-basin, the operating status per 40 CFR 98.236(aa)(1)(ii)(D) through (H), and any well-specific information required for the emission source types directly related to wells. The EPA is proposing to revise 40 CFR 98.236(aa)(1)(ii) and add requirements to 40 CFR 98.236(aa)(1)(iii) that reflect this reporting form structure, with two notable changes. First, the EPA is proposing to no longer require reporting of the sub-basin ID for each well. Instead, reporters would report the sub-basin ID by well-pad and then report the well-pad ID on which the well is located. The well-pad ID is a new proposed data element and is described in the following paragraph. Second, the EPA is proposing to revise the requirements to provide a list of well IDs for the five emission source types directly related to wells (currently required in 40 CFR 98.236(f)(1)(ii), (f)(2)(i), (g)(1), (h)(1)(i), (h)(2)(i), (h)(3)(i), (h)(4)(i), (l)(1)(ii), (l)(2)(ii), (l)(3)(ii), (l)(4)(ii), (m)(1), (m)(7)(i), and (m)(8)(i)) to instead specify that reporters should report emissions and activity data for each of those emission source types by well within the source-specific reporting requirements, as described later in this section.

Second, the EPA is proposing to add the following data elements: well-pad ID (for Onshore Petroleum and Natural Gas Production segment) and gathering and boosting site ID (for Onshore Petroleum and Natural Gas Gathering and Boosting). These proposed data elements are hereafter collectively referred to as ''site-level IDs.'' The EPA is proposing to add to 40 CFR 98.236(aa)(1)(iv) (for Onshore Petroleum and Natural Gas Production) and 40 CFR 98.236(aa)(10)(v) (for Onshore Petroleum and Natural Gas Gathering and Boosting) requirements for reporting of information related to each well-pad ID and gathering and boosting site ID, respectively. The proposed reporting elements for each well-pad ID include a unique name or ID for each well-pad, the sub-basin ID, and the location (*i.e.*, representative latitude and longitude coordinates).

For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the EPA is proposing at 40 CFR 98.236(aa)(10)(v) to require reporters to provide a unique name or ID, the site type, and the location for each gathering and boosting site. For the ''site type'' for each gathering and boosting site, the EPA is proposing that reporters would select between ''gathering compressor station,'' ''centralized oil production site,'' ''gathering pipeline site,'' or ''other fence-line site.'' The EPA is proposing a definition of ''gathering compressor station'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement and to differentiate gathering compressor stations from other types of compressor stations in subpart W (*e.g.*, transmission compressor stations). The Onshore Petroleum and Natural Gas Gathering and Boosting industry segment also includes centralized oil production sites that collect oil from multiple well-pads but that do not have compressors (*i.e.*,

Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at *https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

are not ''compressor stations''). The EPA is also proposing to add a definition of a ''centralized oil production site'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement. For gathering pipelines, the EPA is proposing a definition of ''gathering pipeline site'' to specify that it is all the gathering pipelines at the facility within a single state. In addition, the EPA has received information from stakeholders noting that there are facility configurations that would not clearly fit within the proposed definition for ''gathering compressor station'' or ''centralized oil production site,'' including, but not limited to, booster stations, dehydration facilities, and treating facilities.[64] The EPA is proposing to provide the ''other fence-line site'' site type to cover these types of sites. For gathering pipelines, the EPA is proposing within the definition of ''gathering and boosting site'' that a gathering pipeline site is all the gathering pipelines at the facility within a single state. For the ''location'' reported for each gathering and boosting site, the EPA is proposing that reporters would provide the representative latitude and longitude coordinates where the site type is a gathering compressor station, centralized oil production site or other fence-line facility, and the state where the site type is a gathering pipeline.

For the emission source types in the Onshore Petroleum and Natural Gas Production industry segment directly related to wells that currently report by sub-basin (*i.e.*, well venting for liquids unloading, completions and workovers with hydraulic fracturing, completions and workovers without hydraulic fracturing, and associated gas venting or flaring) or by calculation method and use of a flare (*i.e.*, well testing), we are proposing to require reporting of emissions and activity data for each individual well instead of in the current aggregations (*e.g.*, by sub-basin). Where the current emission source-level provisions of 40 CFR 98.236 for the Onshore Petroleum and Natural Gas Production industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment require reporting at either the facility or the sub-basin level (other than the emission source types directly related to wells), we are proposing to no longer require reporting at the sub-basin level and instead require reporters to provide emissions and activity data by well-pad ID or gathering and boosting site ID for each facility. For emission source types that report at the unit level (*e.g.*, AGRs, dehydrators, and flares), we are proposing to maintain reporting at that level but are proposing to also require the reporter to identify the well-pad ID or gathering and boosting site ID. This proposed requirement would take the place of the reporting of the county or sub-basin ID, if applicable. The EPA is seeking comment as to whether the lower levels of aggregation of activity data to the site level within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments would cause data elements that are currently not entitled to confidential treatment (*i.e.*, data elements that are not considered ''emissions data'' as described in section V of this preamble) to become entitled to confidential treatment. See section V of this preamble for further information about the proposed confidentiality determinations and reporting determinations for inputs to emissions equations.

In addition, the EPA is proposing revisions to the language of existing reporting requirements and proposing to require specific throughput data elements related to wells permanently shut-in and plugged during the reporting year. First, the EPA is proposing to revise the phrase ''permanently taken out of production (*i.e.*, plugged and abandoned)'' in proposed 40 CFR 98.236(aa)(1)(ii)(D) and (H) to read ''permanently shut-in and plugged'' for consistency with the language used in CAA section 136. This proposed amendment is for consistency in language rather than any expected difference in the wells to be reported or the interpretation of the terms. Second, the EPA is proposing to require reporting of the quantities of natural gas, crude oil and condensate produced that is sent to sale during the reporting year for each well that is permanently shut-in and plugged in 40 CFR 98.236(aa)(1)(iii)(C) through (E) for the Onshore Petroleum and Natural Gas Production industry segment and 40 CFR 98.236(aa)(2)(iv) through (vi) for the Offshore Petroleum and Natural Gas Production industry segment. Third, for each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged the EPA is proposing to require reporting of the total quantities of natural gas, crude oil and condensate produced that is sent to sale in the reporting year for the wells on that well-pad. These proposed data elements, if finalized, are anticipated to be useful in the future evaluation of the plugged well provisions of CAA section 136(f)(7).

E. Natural Gas Pneumatic Device Venting and Natural Gas Driven Pneumatic Pump Venting

Subpart W currently requires calculation of GHG emissions from natural gas pneumatic device venting (existing 40 CFR 98.233(a)) and natural gas driven pneumatic pump venting (existing 40 CFR 98.233(c)) using default population emission factors multiplied by the number of devices and the average time those devices are ''in-service'' (*i.e.*, supplied with natural gas). In our 2022 Proposed Rule, we proposed to update the population emission factors for pneumatic devices based on recent study data. Consistent with section II.B of this preamble, we are proposing calculation methods based on measurements and leak screening for each source type as described in this section. Under the proposed calculation methods for pneumatic devices, the existing default population emission factors for intermittent bleed natural gas pneumatic devices would no longer be applicable and the default population emission factors for continuous bleed natural gas pneumatic devices would only be applicable for the leak screening method (proposed Calculation Method 3).

1. Direct Measurement Methods for Natural Gas Pneumatic Devices and Natural Gas Pneumatic Pumps

Consistent with section II.B of this preamble, we are proposing to provide a calculation method based on direct measurement of natural gas supplied to pneumatic devices in proposed 40 CFR 98.233(a)(1) and supplied to pneumatic pumps in proposed 40 CFR 98.233(c)(1). We are proposing that, if a flow monitoring device is installed on the natural gas supply line dedicated to one or a combination of pneumatic devices, or the natural gas supply line dedicated to one or more pneumatic pumps, that are vented directly to the atmosphere, then the measured flow must be used to calculate the emissions from the pneumatic devices or pneumatic pumps, as applicable, downstream of that flow monitor. We are also proposing to require this calculation method when the flow is continuously measured in a supply line that serves both pneumatic devices and natural gas driven pneumatic pumps that are all vented directly to the atmosphere. The

[64] Letter from Angie Burckhalter, The Petroleum Alliance of Oklahoma, to Administrator Michael S. Regan, U.S. EPA, Re: Docket Id. No. EPA–HQ–OAR–2019–0424; Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule. October 6, 2022. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

flow monitor would be required to meet the requirements specified in existing 40 CFR 98.234(b). We are proposing to denote this natural gas supply measurement as Calculation Method 1 for pneumatic devices and pneumatic pumps. We are also proposing to add reporting requirements for each measurement location to report the type of flow monitor, the number of each type of pneumatic device being monitored at that location, and an indication of whether any natural gas driven pneumatic pumps are also monitored at that location, and the CH_4 and CO_2 emissions calculated for that monitoring location in proposed 40 CFR 98.236(b)(3). Comparable reporting requirements for natural gas driven pneumatic pumps are specified in proposed 40 CFR 98.236(c)(3).

For natural gas pneumatic devices that do not have or do not elect to install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic devices that are vented directly to the atmosphere, we are proposing in 40 CFR 98.233(a)(2) to allow reporters to measure the natural gas emissions from each pneumatic device vented directly to the atmosphere at the well-pad, gathering and boosting site, or facility, as applicable, using one of the measurement methods in existing 40 CFR 98.234(b) through (d). We are proposing to refer to the vent measurement method as Calculation Method 2 for pneumatic devices. For natural gas driven pneumatic pumps that do not have or do not elect to install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic pumps vented directly to the atmosphere, we are proposing to require that the reporter either measure the natural gas emissions from each such pneumatic pump at the facility as specified in proposed 40 CFR 98.233(c)(2) or calculate emissions from each such pneumatic pump at the facility using the default emissions factor as specified in proposed 40 CFR 98.233(c)(3). The proposed measurement option is referred to as Calculation Method 2 for pumps and is similar to the proposed Calculation Method 2 for pneumatic devices. The proposed pneumatic pump method based on a default emission factor is the same as the methodology in 40 CFR 98.233(c) of the existing rule and is referred to as Calculation Method 3 in the proposed rule.

If Calculation Method 2 is elected for pneumatic devices, we are proposing that all pneumatic devices that are vented directly to the atmosphere present at the facility (except those for which natural gas supply is measured according to Calculation Method 1) would have to be measured at regular intervals and that for a well-pad, gathering and boosting site, or facility, as applicable, selected to be measured that year, all pneumatic devices that vent to the atmosphere must be measured according to Calculation Method 2 (except those for which natural gas supply is measured according to Calculation Method 1). For facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, a complete cycle of measurements would be required to be completed in no more than 5 years, and we are proposing that the number of pneumatic devices measured each year be approximately equal. We selected a 5-year interval for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities because of the high number of devices at these facilities and the time needed to measure all natural gas pneumatic devices. Additionally, we are proposing that when measurements are conducted at a particular well-pad or gathering and boosting site, all pneumatic devices at that well-pad or gathering and boosting site must be measured in the same year. This would help enhance the representativeness of the measurement data.

For facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, we are proposing the measurement interval to be dependent on the number of devices at the facility. For facilities with 25 or fewer natural gas pneumatic devices, we are proposing measurement of all devices annually. For facilities with 26 to 50 devices, we are proposing measurement of all devices in a two-year period. The proposed interval period increases with every 25 devices, until reaching a maximum cycle time of 5 years for facilities with 101 or more natural gas pneumatic devices that are vented directly to the atmosphere. The 25-device increment was selected because we estimated that this would be the typical number of devices that could be measured following the proposed methods in an 8-hour period.

Under Calculation Method 2, we are proposing that each pneumatic device vent measurement, except for isolation valve actuators, would be conducted for a minimum of 15 minutes; measurements for pneumatic isolation valve actuators would be conducted for a minimum of 5 minutes. We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (*i.e.*, emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations. We are proposing that, if there is a measurable flow during the measurement period, the average flow rate measured during the measurement period would be used as the average flow rate for that device and multiplied by the total hours the device is in service (*i.e.*, supplied with natural gas) to calculate annual emissions (by pneumatic device type). For continuous bleed devices, if there is no measurable flow rate (*i.e.*, flow rate is below the method detection limit), we are proposing to require reporters to confirm the device is in service when measured and that the device type is correctly characterized. Once confirmed, we are proposing that the device must be retested (if designated as a high bleed device) or the manufacturer's steady state bleed rate must be used (if designated as a low bleed device) to estimate the device's emissions. For intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year.

Under Calculation Method 2, if vent measurements are made over several years, we are proposing that all measurements made within a multi-year measurement would be used to calculate a facility-specific emission factor by device type (continuous high bleed, continuous low bleed, and intermittent bleed). The emissions measurements for the pneumatic device vents measured during the reporting year would be used directly for those devices. We are proposing that reporters would use the facility-specific emission factor developed from the cycle of measurements times the number of devices (by type) at the facility that were not measured during the reporting year to calculate the emissions from the pneumatic devices that were not measured during the reporting year.

Reporters using proposed Calculation Method 2 would report for each well-pad, gathering and boosting site, or facility, as applicable, the total number of natural gas pneumatic devices by type, the number of years in the measurement cycle, the number of devices by measured in the reporting year, the value of the emissions factor for the reporting year as calculated using equation W–1A and the devices upon which the emission factor is based, the average time the devices were in service (*i.e.*, supplied with natural gas) during the calendar year, and the GHG emissions for each type of natural gas pneumatic device.

We are proposing calculation and reporting requirements for Calculation Method 2 for pneumatic pumps in proposed 40 CFR 98.233(c)(2) and proposed 40 CFR 98.236(c)(4), respectively, that are similar to the proposed Calculation Method 2 requirements for pneumatic devices, with differences described as follows. First, only facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are currently required to report emissions from pneumatic pumps and based on the analysis performed as described in section III.C.1 of this preamble and documented in the subpart W TSD, we are not proposing to add this source type for any other industry segment. Therefore, proposed Calculation Method 2 for pneumatic pumps only includes the provisions for a 5-year cycle and does not include the measurement cycles for other industry segments. The 5-year cycle is being proposed for natural gas driven pneumatic pumps for the same reason that it is being proposed for pneumatic devices (*i.e.*, a few facilities have a high number of pumps, and the time needed to measure all of the pumps in a single year would be excessive). To minimize the burden while still collecting sufficient data to calculate sufficiently accurate emissions, we are proposing an approach similar to the current approach that Natural Gas Distribution facilities may use to conduct equipment leak surveys. Second, the proposal specifies that reporters would measure for a minimum of 5 minutes while liquid is continuously being pumped. Five minutes is currently specified for other emission measurements in the rule (*e.g.*, leak rates from transmission storage tank vents in existing 40 CFR 98.233(k)(2), which are condensate storage tank vents in this proposal). Typically, emissions from pumps are expected to be greater than leak rates from transmission storage tank leaks. Thus, it is expected that a sufficient volume of sample would be collected in 5 minutes of pump operation to be measurable with sufficient accuracy. Third, we are proposing that the emissions would be calculated as the product of the measured natural gas flow rate and the number of hours the pneumatic pump was pumping. Under proposed Calculation Method 2 for pneumatic pumps, proposed reporting data elements in 40 CFR 98.236(c)(4) per well-pad or gathering and boosting site would include the number of years in the measurement cycle; an indication of whether emissions were measured or calculated; the primary measurement method (when emissions were measured); the value of the calculated emissions factor, the total number of pumps measured and used in calculating the emission factor, the number of pumps that vented to atmosphere, and the estimated average number of hours per year that the vented pumps were pumping liquid (when the emissions were calculated); the total measured CO_2 and CH_4 emissions; and the total calculated CO_2 and CH_4 emissions.

We request comment on whether the option of up to a 5-year cycle is appropriate for all facilities in the onshore production and gathering and boosting industry segments. If a shorter time frame would be appropriate, we request comment on how long the maximum cycle should be and why that length of time would be adequate. We also request comment on the proposed sampling period of 5 minutes. If a longer test period would be needed or a shorter time period would be sufficient to collect representative emissions data, we request comment on what time period would be appropriate and the reasons why that test time would be appropriate. Finally, we request comment on suggestions for other approaches to emissions measurement that might be more effective and better achieve the goal of obtaining accurate vented emissions data from natural gas driven pneumatic pumps.

2. Intermittent Bleed Pneumatic Device Surveys

As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using OGI or other technologies. As noted in the introduction to section II of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for oil and natural gas sources. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc (which would inform the state plans or, if necessary, the Federal plan in 40 CFR part 62), nearly all covered pneumatic devices (continuous bleed and intermittent vent) would be required to have a CH_4 (and, for NSPS OOOOb only, VOC) emission rate of zero. The only proposed exception would be for pneumatic devices in Alaska at locations where on-site power is not available, in which case owners and operators would be required to use low bleed pneumatic devices in place of high bleed pneumatic devices (unless a high bleed device is needed for a functional need such as safety), and to verify that any intermittent bleed pneumatic devices operate such that they do not vent when idle by monitoring these devices during the fugitive emissions survey.

We envision relatively few intermittent bleed pneumatic devices that vent GHG to the atmosphere under the proposed zero-emission standard and presumptive standard for these pneumatic devices, compliance with which would require the use of technology to achieve the zero-emission standard. As noted in the previous paragraph, we proposed in NSPS OOOOb and EG OOOOc to require periodic monitoring of those few intermittent bleed pneumatic devices in Alaska. In addition, as noted in section II of this preamble, the proposed amendments that would apply to sources subject to the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 would not become effective for individual reporters unless and until their emission sources become subject to and are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. Prior to that time, a reporter may elect to conduct inspections or surveys of their intermittent bleed pneumatic devices. Therefore, the EPA is proposing amendments to subpart W to provide an alternative methodology to calculate emissions from intermittent bleed pneumatic devices based on the results of inspections or surveys, consistent with section II.B of this preamble. Specifically, we are proposing to provide in 40 CFR 98.233(a)(3) an alternative calculation methodology for facilities that monitor for malfunctioning intermittent bleed pneumatic devices analogous to a ''leaker factor'' approach used for equipment leaks. We included this ''leaker factor'' approach in the 2022 Proposed Rule; however, we are proposing revisions to the ''leaker factors'' terms included in the calculation approach using peer reviewed study data. We are proposing to refer to this monitoring/leaker factor approach as Calculation Method 3 for pneumatic devices.

If Calculation Method 3 is elected, we are proposing that all intermittent bleed pneumatic devices that vent to the atmosphere at the well-pad, gathering and boosting site, or facility, as applicable, would be required to be monitored according to the leak detection methods in 40 CFR 98.234(a)(1) through (3), but with a monitoring duration of at least 2 minutes or until a malfunction is identified. Based on our review of the measurement studies that identified malfunctioning intermittent bleed devices, we found that most malfunctioning devices could be identified using a 2-minute monitoring duration, but malfunctioning devices could not be identified effectively using a typical ''leak survey'' monitoring duration, which is on the order of a few seconds. However, if a pneumatic device is observed to be malfunctioning in the first minute, there is no need to continue to monitor that device. Therefore, we are proposing that a minimum monitoring duration of 2 minutes or until a malfunction is identified be used for the purpose of identifying malfunctioning intermittent bleed pneumatic controllers.

Under Calculation Method 3, we are proposing that all intermittent bleed pneumatic devices that are vented directly to the atmosphere present at the facility (except those for which natural gas supply is measured according to Calculation Method 1) would have to be monitored to identify malfunctioning devices at regular intervals, with a complete cycle of measurements being completed in no more than 5 years for facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. Additionally, we are proposing that when monitoring is conducted at a particular well-pad or gathering and boosting site, all pneumatic devices at that well-pad or gathering and boosting site must be monitored in the same year. This would help enhance the representativeness of the measurement data. For facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, we are proposing the monitoring interval to be dependent on the number of intermittent bleed pneumatic devices at the facility. For facilities with 100 or fewer natural gas intermittent bleed pneumatic devices, we are proposing monitoring of all devices annually. For facilities with 101 to 200 devices, we are proposing measurement of all devices in a 2-year period. The proposed interval period increases with every 100 devices, until reaching a maximum cycle time of 5 years for facilities with 401 or more natural gas pneumatic devices vented directly to the atmosphere. The 100-device increment was selected because we estimated that this would be the typical number of devices that could be monitored following the proposed methods in an 8-hour period. For all industry segments, we are proposing that, if you elect to monitor your pneumatic devices over multiple years, you must monitor approximately the same number of devices each year.

Under Calculation Method 3, if a ''leak'' is observed from the intermittent bleed pneumatic device for more than 5 seconds during a device actuation, then the device is considered to be ''malfunctioning'' and the malfunctioning device emission factor (similar to a leaker emission factor) would be applied to that device. Emissions from intermittent bleed pneumatic devices that were not observed to be malfunctioning would be calculated based on the default emission factor for ''properly functioning'' intermittent bleed pneumatic devices. We are proposing in the definition of the variable ''T_z'' in proposed equation W–1C that the time that a device is assumed to be malfunctioning would be determined following the same procedures as the determination of the duration of equipment leaks identified during a leak survey conducted under 40 CFR 98.233(q) (see the variable ''$T_{p,z}$'' in equation W–30 for equipment leaks). For example, if only one survey of intermittent bleed natural gas pneumatic devices is conducted during the reporting year, then any device found to be malfunctioning during the survey would be required to be assumed to be malfunctioning for the entire year.

If a complete survey of intermittent bleed pneumatic devices is completed over multiple years, we are proposing equation W–1D be used to calculate the emissions. As proposed, this equation uses the ratio of the number of intermittent bleed devices identified to be malfunctioning during the current reporting year to the total number of intermittent bleed devices monitored during the reporting year to estimate the number of malfunctioning and properly functioning intermittent bleed devices for the intermittent bleed devices that were not monitored during the reporting year.

Under Calculation Method 3, we are proposing that emissions from continuous bleed pneumatic controllers (other than those for which the natural gas supply flow is measured as specified in Calculation Method 1) would be determined either by annually measuring the emissions from the pneumatic device vent following the methods provided in Calculation Method 2 or by using applicable default population emission factors for continuous high bleed and continuous low bleed pneumatic devices.

Reporters using proposed Calculation Method 3 would report for each the well-pad, gathering and boosting site, or facility, as applicable, the total number of natural gas pneumatic devices by type, the method used to estimate emissions from continuous bleed natural gas pneumatic devices, the frequency of monitoring for intermittent devices, the number of years in a monitoring cycle, the number of devices at the facility, the number monitored in the reporting year, the number found to be malfunctioning, the average time the malfunctioning devices were assumed to be malfunctioning under proposed 40 CFR 98.236(b)(5), the average time that devices that were monitored but were not detected as malfunctioning year were in service (*i.e.,* supplied with natural gas) during the calendar year, and the GHG emissions for each type of natural gas pneumatic device.

For more information regarding this proposed alternative calculation methodology for natural gas intermittent bleed pneumatic devices, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

3. Revisions to Emission Factors

As noted in section III.E of this preamble, subpart W currently requires calculation of GHG emissions from natural gas pneumatic device venting using default population emission factors multiplied by the number of devices and the average time those devices are ''in-service'' (*i.e.,* supplied with natural gas). Correspondingly, the current default population factors for natural gas pneumatic devices were developed by taking both periods of actuation and periods without actuation into account. Subpart W provides two sets of pneumatic device emission factors, one for devices in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments and one for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments. Each set of emission factors consists of emission factors for three different types of natural gas pneumatic devices: continuous low bleed devices, continuous high bleed devices, and intermittent bleed devices.[65]

The EPA has become aware of several studies on emissions from natural gas pneumatic device vents since subpart W was first promulgated. For example, in April 2015, the EPA reviewed three recently published studies on emissions from pneumatic devices (also referred to as ''pneumatic controllers'' within the studies as well as in NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc) at onshore production facilities and evaluated those studies for use in the U.S. GHG Inventory.[66] As part of this proposed rulemaking, we have reviewed these and other available studies to evaluate the potential for revisions to the natural gas pneumatic device emission factors in subpart W. As part of our review, we found there are significantly more data available now by which to characterize pneumatic device emissions. Therefore, consistent with section II.B of this preamble, we are proposing to amend the emission factors for all industry segments for which emissions from natural gas pneumatic device vents must be calculated.

Under Calculation Method 3 for pneumatic devices, default population emission factors can be used for continuous bleed devices. Therefore, for continuous low bleed pneumatic devices, we are proposing an emission factor of 6.8 standard cubic feet per hour per device (scf/hr/device) based on the available measurement data, which considers devices that may be malfunctioning (*i.e.,* having higher steady state bleed rates than specified by the manufacturer) for all applicable industry segments in proposed Table W–1. For continuous high bleed pneumatic devices, we are proposing different population emission factors depending on the applicable industry segment. For facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, we are proposing an emission factor of 21 scf/hr/device for continuous high bleed devices in existing Table W–1A (proposed Table W–1) based on study data for these industry segments. For facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, we are proposing an emission factor of 30 scf/hr/device for continuous high bleed devices in proposed Table W–1 based on study data from transmission compression stations. These proposed continuous bleed emission factors consider emissions from pneumatic devices based on measurements while the devices are in service, not just actuating.

Because none of the three proposed calculation methods described in section III.E.1 and 2 of this preamble would allow the use of the current default population emission factor methodology for intermittent bleed pneumatic devices, we are proposing to remove the population emission factors for intermittent bleed pneumatic devices from existing Tables W–1A, W–3B, and W–4B and not include them in proposed Table W–1. The EPA requests comment on whether the EPA should instead retain the use of default population emission factors as an alternative calculation methodology (as Calculation Method 4) for sites, *i.e.* include in the final rule an option for sites to not conduct measurements or monitor intermittent bleed devices. If the population emission factor calculation method is retained, the EPA requests comment on the appropriate intermittent bleed pneumatic device emission factors to include in the final rule. Based on our review of the recently published pneumatic device study data, we would consider revising the intermittent bleed pneumatic device emission factor for facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to 8.8 scf/hr/device. This emission factor considers emissions from pneumatic devices based on measurements while the devices are in service, not just actuating, and may include emissions from devices that were malfunctioning during the time of the measurement. We have limited new data specific to intermittent bleed pneumatic devices for other industry segments. We would consider retaining the intermittent bleed pneumatic device emission factor of 2.3 scf/hr/device for facilities in other applicable industry segments; however, this emission factor is based on engineering calculations and would likely underestimate emissions from devices that are malfunctioning (*e.g.,* bleeding continuously or bleeding more than expected during an actuation). The EPA requests comment and supporting data regarding potential revisions to the intermittent bleed pneumatic device population emission factors, if the use of population emission factors as a calculation methodology is retained.

For more information regarding this review and development of the proposed emission factors, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

Finally, we note that we are not proposing to revise or remove the default population emission factor in existing Table W–1A (proposed Table W–1) for natural gas driven pneumatic pumps. Reporters that do not have or elect to install a flow meter on the natural gas supply line dedicated to any one or more natural gas driven pneumatic pumps and that do not elect to measure the volumetric flow rate of emissions from all the natural gas driven pneumatic pumps vented directly to the atmosphere at a well-pad or gathering and boosting site would be required to continue using the current default population emission factor for pneumatic pumps vented directly to the atmosphere, as proposed Calculation Method 3. The existing emission factor is based on the average stroke volumes and frequencies for a range of typical pumps.[67] In contrast to some other equipment for which emission factors are currently used to calculate emissions (*e.g.,* intermittent bleed pneumatic devices), the emissions per unit of operating time for a given pump are not expected to vary significantly due to malfunctions as the pump ages. As such, we expect the natural gas

[65] The development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[66] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Potential Revisions to Pneumatic Controller Emissions Estimate (Production Segment).* April 2015. Available at *https://www.epa.gov/sites/production/files/2015-12/documents/ng-petro-inv-improvement-pneumatic-controllers-4-10-2015.pdf.*

[67] *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps, Final Report.* GRI–94/0257.30 and EPA–600/R–96–080m. Gas Research Institute and U.S. Environmental Protection Agency. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

driven pneumatic pump emission factor to provide an acceptably accurate estimate of the average hourly emissions from natural gas driven pneumatic pumps. For this reason, we are proposing to retain the emission factor calculation method for this source type.

In the 2022 Proposed Rule we proposed clarifying the definition of the time parameter in equation W–2 of the current rule. The current definition is the ''average estimated number of hours in the operating year that the pumps were operational.'' We proposed changing the word ''operational'' to ''in service (*i.e.,* supplied with natural gas).'' This change was proposed to be consistent with the proposed change to the time term in equation W–1 for pneumatic devices. This change was proposed for the pneumatic device equation because the specified emission factors were developed based on emission measurement tests conducted over periods when the devices were actuating as well as periods when they were not actuating (*i.e.,* theoretical steady-state continuous bleeding, or for intermittent devices, when they theoretically were not emitting). However, after further review, we determined that the current emission factor for pneumatic pumps was developed based on observations of pump operation at several production facilities (*e.g.,* stroke rates and frequency of pump use) and pump manufacturer data (*e.g.,* gas consumption per volume of chemical pumped, plunger diameter, and stroke length) for a variety of chemical injection pumps.[68] This means the emission factor represents emissions when pumps are actuating, or, in other words, when they are actively pumping liquid. Thus, we are now proposing to clarify the definition of the term ''T'' in current equation W–2 (equation W–2B in proposed 40 CFR 98.233(c)) by replacing the word ''operational'' with ''pumping liquid.'' We request comment on the potential for natural gas to leak through a pump to the atmosphere when the pump is not actively pumping liquid and the mechanism for such leakage.

4. Hours of Operation of Natural Gas Pneumatic Devices

In correspondence with the EPA via e-GGRT, some reporters have indicated that they are interpreting the term ''operational'' in the definition of variable ''T_t'' in equation W–1 in 40 CFR 98.233(a) and the term ''operating'' in the reporting requirements in 40 CFR 98.236(b)(2) differently than the EPA intended. Both the current emission factors and the proposed calculation methodologies described in sections III.E.1 through III.E.3 of this preamble for natural gas pneumatic devices were developed by taking both periods of actuation and periods without actuation into account;[69] in other words, the emission factors are population emission factors considering all times when the device was connected to natural gas supply line. To calculate emissions accurately using the existing population emission factor, the average number of hours used in equation W–1 should be the number of hours that the devices of a particular type are in service (*i.e.,* the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed). Similarly, based on the calculation methodology for the site-specific population emission factor in Calculation Method 2 or for the leaker emission factor approach proposed in Calculation Method 3, the number of hours that the devices of a particular type are in service (*i.e.,* the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed) must be used in the calculation, Therefore, consistent with section II.D of this preamble, we are proposing to revise the definition of variable ''T_t'' in existing equation W–1 (proposed equation W–1B) in 40 CFR 98.233 and the corresponding reporting requirements in proposed 40 CFR 98.236(b)(4)(ii)(C)(4), (b)(4)(iii)(C)(4), and (b)(5)(i)(C)(2) to use the term ''in service (*i.e.,* supplied with natural gas)'' rather than ''operational'' or ''operating,'' to clarify the original and current intended meaning of that variable and term. We are also proposing to use this ''in service'' language for the time variables in the newly proposed equations W–1C and W–1D for the leaker factor approach for intermittent bleed pneumatic devices under Calculation Method 3.

5. Natural Gas Pneumatic Devices and Natural Gas Driven Pneumatic Pumps Routed to Control

We understand that emissions from some natural gas pneumatic devices and/or natural gas driven pneumatic pumps are routed to control (*i.e.,* a flare, combustion unit, or vapor recovery system). The population emission factor is based on natural gas vented directly to the atmosphere from these pneumatic devices/pumps and does not accurately reflect emissions from controlled pneumatic devices/pumps. Therefore, consistent with section II.B of this preamble, we are proposing to revise 40 CFR 98.233(a) and (c) to clarify requirements for calculating emissions from natural gas pneumatic devices and natural gas driven pneumatic pumps, respectively, that are vented directly to the atmosphere versus pneumatic devices/pumps that are routed to control, consistent with the intent of the current rule. We are proposing revisions to 40 CFR 98.233(a) and (c) to clarify that the existing population emission factor calculation methodology is intended to apply only to pneumatic devices/pumps vented directly to the atmosphere. The proposed new calculation methodologies described in sections III.E.1 and 2 of this preamble also specify that they apply only to pneumatic devices/pumps vented directly to the atmosphere.

We are proposing that flared emissions from natural gas pneumatic devices or pumps are not required to be calculated and reported separately from other flared emissions. We are proposing to specify that instead emission streams from natural gas pneumatic devices or pumps that are routed to flares are required to be included in the calculation of total emissions from the flare according to the procedures in 40 CFR 98.233(n) and reported as part of the total flare stack emissions according to the procedures in 40 CFR 98.236(n), in the same manner as emission streams from other source types that are routed to the flare. Similarly, we are proposing that emissions from natural gas pneumatic devices or pumps that are routed to a combustion unit are required to be combined with other streams of the same fuel type and used to calculate total emissions from the combustion unit as specified in 40 CFR 98.233(z) and reported as part of the total emissions from the combustion unit as specified in 40 CFR 98.236(z). We are also proposing reporters would not calculate or report emissions from natural gas pneumatic devices or pumps if the emissions are routed to vapor

[68] *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps, Final Report.* GRI–94/0257.30 and EPA–600/R–96–080m. Gas Research Institute and U.S. Environmental Protection Agency. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[69] As noted previously, the development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

recovery and are not subsequently routed to a combustion device (*e.g.,* are routed back to process or sales).

We are also proposing to require in proposed 40 CFR 98.236(b)(2) and 98.236(c)(2) reporting of the total number of continuous low bleed, continuous high bleed, and intermittent bleed natural gas pneumatic devices and the total number of natural gas driven pneumatic pumps at the site (regardless of vent disposition), the number of these devices/pumps that are vented to the atmosphere for at least a portion of the year, and the number of these devices/pumps that are routed to control for at least a portion of the year (which includes natural gas pneumatic devices/pumps routed to a flare, combustion unit, or vapor recovery system). The total count of pneumatic devices or pumps is a proposed reporting element because the total count may not always be equal to the sum of the other two counts. For example, a reporter that switches from atmospheric venting to routing to control during a year for a particular pneumatic device or pump would include that pneumatic device or pump in both the count of devices or pumps that vent directly to atmosphere and in the count of devices or pumps that are routed to flares. However, that pneumatic device or pump would only be counted once towards the total number of pneumatic devices or pumps, allowing us to discern the number of devices or pumps that exclusively vent or exclusively route to control. The number of pneumatic devices or pumps vented directly to the atmosphere would be used in the verification of annual reports to the GHGRP. The total count of pneumatic devices or pumps at the facility and the number of pneumatic devices or pumps that are routed to a flare, combustion, or vapor recovery would provide the EPA with information to better characterize emissions from this source, including how many pneumatic devices or pumps are controlled across the industry and how the use of controls for pneumatic pumps changes across multiple years.

F. Acid Gas Removal Unit Vents

1. Reporting of Methane Emissions From Acid Gas Removal Units

Reporters currently report only CO_2 emissions from AGR vents using one of the four calculation methodologies provided in 40 CFR 98.233(d). In the 2010 subpart W TSD, the EPA explained that ''CH_4 emissions from AGR vents are insignificant, 0.06 percent of the total volume of CO_2 and CH_4 emissions,'' leading to the decision at that time not to require reporting of CH_4 emissions from AGR vents.[70] However, as described in more detail later in this section, both the number and size of the AGRs reported to the GHGRP in recent years are greater than the values used in that initial assessment, so current nationwide CH_4 emissions are likely greater than estimated in the 2010 subpart W TSD.

To determine the potential sources to be evaluated for inclusion in the original subpart W, the EPA used the emissions for the year 2006 as published in the 2008 U.S. GHG Inventory.[71] As documented in the 2010 subpart W TSD, the EPA estimated that AGR vents emitted 643 MMscf of CH_4 that year, which corresponds generally to the 12,380 mt CH_4 from AGR vents shown in Table A–114 of the 2008 U.S. GHG Inventory. The inputs for that estimate include the emission factor for AGR vents from *Volume 14: Glycol Dehydrators* of the 1996 GRI/EPA study (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234), and an estimate of about 290 AGRs at processing plants, scaled from the 1992 estimate of 371 AGRs presented in the GRI/EPA study. However, the emission factor in the 1996 GRI/EPA study is based on an AGR throughput of about 35 MMscf per day, while the average feed rate of the AGRs reported at onshore natural gas processing plants in RY2021 was around 78 MMscf per day and the average feed rate of all reported AGRs in RY2021 was around 59 MMscf per day. In addition, there were 391 AGRs reported at onshore natural gas processing plants and 579 total AGRs reported in RY2021. In other words, the total quantity of natural gas treated in AGRs in RY2021 at onshore natural gas processing plants was about three times the total amount of natural gas estimated to be treated by the 2008 U.S. GHG Inventory. Therefore, the CH_4 emissions from AGR vents are likely to be significantly greater than estimated in the 2010 subpart W TSD, and as such, the EPA is proposing to amend 40 CFR 98.233(d) and 98.236(d) to require calculation and reporting of those emissions. The proposed inclusion of reporting for emissions of CH_4 from AGR vents would improve the coverage of total CH_4 emissions reported to subpart W, consistent with section II.A of this preamble. For more information on the estimation of potential CH_4 emissions from AGR vents, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

There are four calculation methods currently provided in 40 CFR 98.233(d) for calculating CO_2 emissions from AGR vents. Calculation Method 1 is to use a continuous emissions monitoring system (CEMS) if one is installed (40 CFR 98.233(d)(1)), and Calculation Method 2 requires the use of a vent flow meter if there is one installed that is not part of a CEMS and use either a continuous gas analyzer or quarterly gas samples for composition (40 CFR 98.233(d)(2)). If neither a CEMS nor a vent flow meter is installed, reporters currently may use Calculation Method 3, engineering equations (40 CFR 98.233(d)(3)), or Calculation Method 4, modeling simulation via software (40 CFR 98.233(d)(4)).

As part of this proposal, the EPA evaluated the existing calculation methods for the purpose of proposing to require CH_4 emissions from AGR vents, and based on that assessment, Calculation Methods 2, 3, and 4, are generally appropriate to use for CH_4. Calculation Method 1 is not considered an option for CH_4 because the EPA is not currently aware of continuous CH_4 monitors that meet the EPA's criteria for CEMS.[72] Therefore, the EPA is proposing to specify that reporters must use Calculation Method 2 to calculate CH_4 emissions if they have a vent flow meter installed (including the flow meter of a CO_2 CEMS) and is proposing to revise the subscripts of the variables in equation W–3 slightly to specify that reporters should calculate both CO_2 and CH_4. If there is no vent flow meter, the EPA is proposing that reporters would choose between Calculation Method 3 or Calculation Method 4. For Calculation Method 4, the EPA is proposing to add the CH_4 content of the feed natural gas and the outlet natural gas as parameters that must be used to characterize emissions. This specification is analogous to the existing requirement to use acid gas content of the feed natural gas and the acid gas content of outlet natural gas to characterize CO_2 emissions. For Calculation Method 3, the EPA is proposing to revise the existing equations W–4A and W–4B and to add

[70] *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[71] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2006.* April 2008. Available at *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2006* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[72] See *https://www.epa.gov/emc/emc-continuous-emission-monitoring-systems* for more information on CEMS.

a new equation W–4C. With the addition of CH_4 as a component for these equations, reporters would need to have information on four parameters rather than the three they currently need to know. For more information on the derivation of these proposed equations, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. We request comment on whether these are the appropriate methods for calculating CH_4 from AGR vents, including whether there are continuous CH_4 monitors that meet the EPA's criteria for CEMS.

Although we used the 1996 GRI/EPA emission factor to assess the potential magnitude of CH_4 emissions from AGR vents, both in the 2010 subpart W TSD and for an initial assessment of whether to include additional reporting requirements in this proposal, we are not proposing use of that emission factor as a method for calculating emissions under subpart W. That emission factor is based on modeling of an average system from many years ago, and as discussed earlier in this section, the model AGR is much smaller than the AGRs reported to subpart W more recently. The emission factor is per AGR, so it does not take into account the feed rate of the AGR, the concentration of CO_2 entering the unit, or the level of treatment (*i.e.,* concentration of CO_2 exiting the unit).

The EPA is also proposing to add relevant reporting elements for CH_4 from each AGR to 40 CFR 98.236(d). The additional data elements include annual CH_4 emissions vented directly to the atmosphere; annual average volumetric fraction of CH_4 in the vent gas if using Calculation Method 2; additional inputs for Calculation Method 3, depending on the equation used (*i.e.,* as applicable, the annual average volumetric fraction of CH_4 in the natural gas flowing out of the AGR, annual average volumetric fraction of CH_4 content in natural gas flowing into the AGR, annual average volumetric fraction of CO_2 in the vent gas exiting the AGR and annual average volumetric fraction of CH_4 in the vent gas exiting the AGR); and the CH_4 content of the feed natural gas and outlet natural gas if using Calculation Method 4.

Finally, we note that under the current provisions of subpart W, reporters with AGRs routed to flares are required to report the CO_2 emissions from the AGR that pass through the flare as AGR vent emissions, and the emissions that result from combustion of any CH_4 in the AGR vent stream are reported as flare stack emissions. In the 2022 Proposed Rule, we proposed to provide more clarity regarding how to determine the flow rate and composition of the gas routed to a flare if Calculation Method 3 or 4 were used to calculate CO_2 emissions. Because we are proposing to require reporting of CH_4 emissions from AGR vents, there would be no reason for subpart W to include special provisions for AGR vents routed to flares that are different from the provisions for all other emission source types routed to flares. Instead, the EPA is proposing that AGR vents routed to a flare would follow the same calculation requirements as other emission source types and would begin reporting flared AGR emissions (CO_2, CH_4, and N2O) separately from vented AGR emissions (CO_2 and CH_4). See section III.N of this preamble for more information on the proposed flaring calculation and reporting provisions. In a similar amendment, we are proposing to specify that AGR vents routed to an engine would calculate CO_2, CH_4, and N2O emissions using the provisions of 98.233(z) or subpart C, whichever is applicable to that industry segment. We are also proposing that AGRs routed to a flare or engine for the entire year would report the information in proposed 40 CFR 98.236(d)(1) except for the calculation method, the indication of whether any CO_2 emissions were recovered and transferred offsite, and the CO_2 and CH_4 emissions from the unit. If the AGR routed to a flare or an engine only for part of the year, the other information in proposed 40 CFR 98.236(d)(1) would be required to be reported for the part of the year in which emissions were vented directly to the atmosphere.

2. Calculation Method 4

Reporters with AGRs that elect to calculate emissions using Calculation Method 4 are currently required to calculate emissions using any standard simulation software package that uses the Peng-Robinson equation of state and speciates CO_2 emissions. According to existing 40 CFR 98.233(c)(4), the information that must be used to characterize emissions include natural gas feed temperature, pressure, flow rate, and acid gas content; outlet natural gas acid gas content and temperature; unit operating hours; and solvent temperature, pressure, circulation rate, and weight. These parameters currently must be determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data. Consistent with section II.B of this preamble, we are proposing that the input parameters related to the natural gas feed that are used for the simulation software must be obtained by measurement. Those parameters include natural gas feed temperature, pressure, flow rate, acid gas content, CH_4 content, and, for nitrogen removal units, nitrogen content. We are proposing that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. We are not proposing to change the requirement that the other parameters must be determined for operating conditions based on engineering estimate and process knowledge.

We are also proposing that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this proposed change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year. Finally, we are proposing to clarify that the information reported under 40 CFR 98.236(d)(2)(ii) should be provided on an annual basis, either as an average across the year, or a total for the year (in the case of operating hours for the unit).

We are also proposing an additional change to the reported data for reporters with AGRs that elect to calculate emissions using Calculation Method 4. One of the required inputs to report is the solvent weight, in pounds per gallon (under existing 40 CFR 98.236(d)(2)(iii)(L)). A variety of different solvents may be used in an AGR (*e.g.,* chemical solvents such as monoethanolamine (MEA) and methyl diethanolamine (MDEA), physical solvents such as Selexol™ and Rectisol®), and the solubility of CO_2 varies across the different types of solvent. Requiring reporters to provide solvent characteristics provides information about the type of solvent used so the emissions calculated by the modeling run could be verified. However, the ''solvent weight'' is the only data element related to the identification of the solvent that is currently collected, and the values reported across all reporters have been inconsistent over the last few years, indicating that this data element is likely not clear to reporters (*e.g.,* some reporters appear to be providing the density of the solvent and others appear to be providing the amine concentration in weight percent). In addition, the densities of common amine-based solvents are fairly close in value, so even among reporters that are providing values within the expected range of solvent densities, we have found it difficult to use this data element to identify the solvent type. Finally, the current requirement to report solvent weight does not specify how this value should be determined, but given the precise values being reported, it appears that reporters are either measuring the solvent or reporting a specific value provided by the vendor.

Therefore, we are proposing to replace the existing requirement to report solvent weight with a requirement (proposed 40 CFR 98.236(d)(2)(iii)(N)) to report the solvent type and, for amine-based solvents, the general composition. Reporters would choose the solvent type option from a pre-defined list that most closely matches the solvent type and, for amine-based solvents, the general composition, used in their AGR. The standardized response options would include the following: ''Selexol™,'' ''Rectisol®,'' ''Purisol™,'' ''Fluor Solvent℠,'' ''Benfield™,'' ''20 wt% MEA,'' ''30 wt% MEA,'' ''40 wt% MDEA,'' ''50 wt% MDEA,'' and ''Other (specify).'' We are proposing to use commercially available trade names in this list rather than chemical compositions, as the trade names are more commonly used among AGR operators and therefore more readily available. This proposed amendment to collect standardized information about the solvent is expected to result in more useful data that would improve verification of reported data and better characterize AGR vent emissions, consistent with section II.C of this preamble. It would also improve the quality of the data reported compared to the apparently inconsistent application of the current requirements. In addition, the solvent type and composition rarely change from one year to the next, so once the data element is reported the first time, most reporters would be able to copy the response from the previous year's reporting form each year. Therefore, the proposal to require reporters to select a solvent type and composition from these standardized responses is also expected to improve verification and the consistency of reported data compared to the current requirement, consistent with section II.C of this preamble. In the event that reporters use more than one type of solvent in their AGR during the year, the proposed reporting requirement specifies that reporters would select the option that corresponds to the solvent used for the majority of the year.

3. Reporting of Flow Rates

We are proposing several amendments to improve the quality and verification of AGR flow rate information, consistent with sections II.C of this preamble. Reporters are currently required to report the total feed rate entering the AGR in units of million cubic feet per year (existing 40 CFR 98.236(d)(1)(iii), proposed 40 CFR 98.236(d)(1)(iv)). The existing rule does not specify million standard cubic feet per year or million actual cubic feet per year, so reporters may provide this feed rate in either of those units of measure. However, there is not currently a requirement for reporters to provide the actual temperature and pressure for the total feed rate if it is reported in million actual cubic feet, so it is difficult for the EPA to tell which are the correct units of measure. Reporters also provide flow rates that correspond with the calculation method chosen, and the subpart W reporting form currently requests the temperature and pressure corresponding to those flow rates, but they cannot necessarily be used to clarify the units of measure for the total feed rate. For example, for Calculation Method 1 or 2, reporters provide the annual volume of gas vented from the AGR in cubic feet (existing 40 CFR 98.236(d)(2)(i)(B), proposed 40 CFR 98.236(d)(2)(i)(C)), but the temperature and pressure of this vent gas does not correlate directly to the temperature and pressure for the AGR feed rate. In addition, while the reporting form requests the temperature and pressure corresponding to various flow rates, those data elements are not specifically included in 40 CFR 98.236(d), so there appears to be some inconsistency between the flow rates reported and the temperature and pressure reported. For example, in some cases, the flow rate appears to be reported in standard cubic feet but the temperature and pressure appear to represent actual conditions; in these cases, the temperature and pressure may have been the values used to convert the flow rate from actual conditions to the reported standard conditions, but it is not clear. As a result, the EPA has found it difficult to verify the AGR flow rates in some cases.

Therefore, we are first proposing to require that the total annual feed rate that is required to be reported for all AGRs regardless of the how the emissions are calculated (existing 40 CFR 98.236(d)(1)(iii), proposed 40 CFR 98.236(d)(1)(iv)) would be reported at standard conditions (*i.e.,* in units of MMscf per year). The revisions would make the units of measure for this total annual feed rate more consistent with the natural gas throughputs reported for each industry segment in existing 40 CFR 98.236(aa) and would standardize the units of measure for this total annual feed rate across all AGRs. Stakeholders have previously indicated that standard industry practice for either calculating or measuring the flow of gas into or out of an AGR would be in standard conditions.[73] Based on the data reported from RY2015 to RY2021, the EPA estimates that at least 80 percent of the AGR total annual feed rates were reported in MMscf per year (for the remaining 20 percent of the AGRs, the EPA either was able to determine that the AGR feed rate was reported in million actual cubic feet per year, or it is unclear whether the feed rate was reported in actual or standard conditions). Therefore, this proposed revision is not expected to result in changes for the majority of the reporters but would improve the quality of the overall data.

Second, we are proposing to specifically require the temperature and pressure that correspond to the flow rates reported for Calculation Methods 1, 2, or 3 (reporters using Calculation Method 4 are already required to report the temperature and pressure of the acid gas feed, under existing 40 CFR 98.236(d)(2)(iii)(B) and (C)). Depending on the calculation method selected, reporters are required to provide the vent gas flow rate, flow rate of natural gas into the AGR, and/or the flow rate of natural gas out of the AGR. The calculation methodologies in existing 40 CFR 98.233(d)(1) through (3) and the reporting requirements in existing 40 CFR 98.236(d)(2)(i) and (ii) accommodate use of flow rates in either actual or standard conditions to calculate emissions. The proposed additions, at proposed 40 CFR 98.236(d)(2)(i)(D) and (E) and (d)(2)(ii)(I), (J), (L), and (M), specify that reported temperature and pressure should be the actual temperature and pressure if the flow rate is reported in actual conditions, or standard temperature and pressure if the flow rate is reported in standard conditions. These proposed additions would provide the EPA with the ability to verify the emissions calculations more

[73] E.g., see U.S. EPA. *Response to Public Comments on Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*, November 2014, Comment EPA–HQ–OAR–2011–0512–0084–A2, Excerpt Number 73.

efficiently and would provide a more consistent data set overall.

G. Dehydrator Vents

Dehydrators are used to remove water from produced natural gas prior to transferring the natural gas into a pipeline or to a gas processing facility. Subpart W requires reporting of GHG emissions from dehydrator vents at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas processing facilities. Emissions are determined using one of the calculation methodologies for glycol dehydrators provided in existing 40 CFR 98.233(e) based on the unit's annual average daily natural gas throughput. For glycol dehydrator units with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per existing 40 CFR 98.233(e)(2) (Calculation Method 2). For glycol dehydrator units with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day, reporters must follow the provisions under existing 40 CFR 98.233(e)(1), which require modeling GHG emissions using a software program (*e.g.*, AspenTech HYSYS® [74] or GRI–GLYCalc™ [75]) (Calculation Method 1). Facilities with desiccant dehydrators calculate volumetric CO_2 and CH_4 emissions using equation W–6 and the provisions of existing 40 CFR 98.233(e)(3) (Calculation Method 3). In the 2022 Proposed Rule, the EPA proposed to remove the emissions calculation and reporting requirements for desiccant dehydrators per 40 CFR 98.233(e)(3) and 40 CFR 98.236(e)(3). However, to avoid potential gaps in emissions data and improve the accuracy of the data collected in the GHGRP (consistent with section II.A of this preamble), the EPA is not proposing the removal of desiccant dehydrator requirements in this proposal.

1. Selection of Appropriate Calculation Methodologies for Glycol Dehydrators

As noted in section III.G of this preamble, for dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per Calculation Method 2 (40 CFR 98.233(e)(2)) and report emissions per 40 CFR 98.236(e)(2). Reporters with glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 MMscf per day are currently required to model their dehydrator emissions per Calculation Method 1 (40 CFR 98.233(e)(1)). Through requests submitted to the GHGRP Help Desk and correspondence with the EPA via e-GGRT, reporters have indicated the desire to use Calculation Method 1 for determining emissions from dehydrators that have a throughput that is less than 0.4 MMscf per day, as they stated that the population emission factors provided in 40 CFR 98.233(e)(2) are not always representative of their dehydrators' actual emissions. Process simulations and models require unit-specific inputs, so it is reasonable to expect that they would result in more accurate emissions estimates for dehydrators that have differing operating characteristics than those used to develop the Calculation Method 2 emission factors. Therefore, we are proposing to revise the calculation requirements of 40 CFR 98.233(e) to allow reporters the ability to use Calculation Method 1 or Calculation Method 2 when determining emissions from dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 MMscf per day. We are also proposing to specify that if a facility is required to or elects to perform emissions modeling of a glycol dehydrator consistent with the methodology outlined in 40 CFR 98.233(e)(1), they must use the results of the model for estimating emissions under 40 CFR 98.233(e). It is the EPA's intention with this proposal that if reporters conduct modeling for environmental compliance or reporting purposes, including but not limited to compliance with Federal or state regulations, air permit requirements, annual inventory reporting, or internal review, they would use those results for reporting under subpart W. The EPA is also proposing revisions to 40 CFR 98.236(e) to specify the applicable reporting requirements based on the selected calculation method rather than the throughput of the dehydrator. This amendment is expected to improve the quality of the data collected, consistent with section II.B of this preamble.

2. Controlled Dehydrators

In correspondence with the EPA via e-GGRT, some reporters have asked the EPA for guidance regarding calculating emissions from dehydrators that are routed to different control devices throughout the reporting year (*e.g.*, dehydrators that are routed to vapor recovery and subsequently vented to atmosphere or routed to a flare when the vapor recovery device is not operating). Given the proposed amendments to the calculation methodology and reporting of flare stack emissions (discussed in section III.N of this preamble), we are proposing to revise the methodologies for calculating emissions from dehydrator vents controlled by a vapor recovery system, flare, or regenerator firebox/fire tubes currently provided in 40 CFR 98.233(e)(5) and (6), respectively. The new language in proposed 40 CFR 98.233(e)(4) provides a methodology for calculating emissions vented directly to the atmosphere during periods of time when emissions are not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes. For flared dehydrator emissions, the proposed 40 CFR 98.233(e) provisions would direct reporters to the proposed methodologies in 40 CFR 98.233(n). As a regenerator firebox/fire tubes does not meet the definition of a flare per 40 CFR 98.238, we are proposing methodologies for calculating combusted emissions from a regenerator firebox/fire tubes in 40 CFR 98.233(e)(5) using the combustion source equations W–39A, W–39B, and W–40 of 40 CFR 98.233(z)(3). We are also proposing new reporting requirements for dehydrator units with emissions routed to a firebox/fire tubes in proposed 40 CFR 98.236(e)(1)(xvi) and (xvii), (e)(2)(v), and (e)(3)(vii) that are consistent with the reporting requirements for combustion sources in 40 CFR 98.236(z)(2). By proposing these amendments, the EPA seeks to enhance the overall quality of the data collected under the GHGRP, consistent with sections II.B and II.D of this preamble.

The EPA is also proposing revisions to two terms consistent with the proposed amendments for reporting for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. The EPA is proposing to amend the definition of ''dehydrator vent emissions'' in 40 CFR 98.6 to confirm that dehydrator emissions reporting should include emissions from both the dehydrator still vent, and if applicable, the dehydrator flash vent. We are also proposing to remove the term ''reboiler'' from the definition, as the term ''regenerator'' refers to the same piece of equipment. Finally, we are proposing to expand the dehydrator control types referenced in the definition to include regenerator fireboxes/fire tubes and vapor recovery systems. Additionally,

[74] AspenTech HYSYS® software available from AspenTech website (*https://www.aspentech.com/*).

[75] GRI–GLYCalc™ software available from Gas Technology Institute website (*https://sales.gastechnology.org/*).

the EPA is proposing to amend the definition of ''vapor recovery system'' in 40 CFR 98.6 to clarify that routing emissions from a dehydrator regenerator still vent or flash tank separator vent to the regenerator firebox/fire tubes does not qualify as vapor recovery for purposes of 40 CFR 98.233. The EPA has noted significant variability in the dehydrator emissions values reported over the past several years, with values ranging from extremely high to almost negligible emissions, which indicates that there are likely inconsistencies in how these terms are being interpreted among subpart W reporters. In proposing these edits, the EPA expects to improve the quality of the emissions data reported and confirm the original intent of these terms.

3. Calculation Method 1 for Glycol Dehydrators

Reporters with glycol dehydrator units that calculate emissions using Calculation Method 1 are currently required to determine emissions using any standard simulation software package that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient; speciates CH_4 and CO_2 emissions from dehydrators; and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. According to current 40 CFR 98.233(e)(1), the information that must be used to characterize emissions include natural gas feed flow rate and water content; outlet natural gas water content; absorbent circulation pump type, circulation rate, and absorbent type; use of stripping gas, use of flash tank separator (and disposition of recovered gas), hours operated, wet natural gas temperature, pressure, and composition. These parameters currently must be determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data. Consistent with section II.B of this preamble, we are proposing that the input parameters related to the natural gas feed that are used for the simulation software must be obtained by measurement. Those parameters include feed natural gas flow rate, feed natural gas water content, wet natural gas temperature and pressure at the absorber inlet, and wet natural gas composition. We are proposing that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. We are not proposing to change the requirement that the other parameters must be determined for operating conditions based on engineering estimate and process knowledge.

We are also proposing that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this proposed change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year. Finally, we are proposing to clarify that the information reported under 40 CFR 98.236(e)(1) should be provided on an annual basis, either as an average across the year, or a total for the year (in the case of operating hours for the unit).

Subpart W currently lists two example software options, AspenTech HYSYS® and GRI–GLYCalc™ (GLYCalc), that meet the software requirements in 40 CFR 98.233(e)(1). Reporters are not limited to only using these two example software options. However, the EPA recently approved the use of ProMax [76] software simulations for compliance with 40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Gas Production Facilities (hereafter referred to as ''NESHAP HH'').[77] In the approval letter, the EPA concluded that the ProMax model results are typically equivalent or more conservative when compared to the results from the GLYCalc model and the total capture condensation method used by the EPA in its research. After considering this issue, we expect that ProMax meets the specifications of existing 40 CFR 98.233(e)(1) and, therefore, we are proposing to add ProMax as an example software program for calculating dehydrator emissions in 40 CFR 98.233(e)(1) for clarity for reporters. Consistent with the EPA's approval of ProMax for NESHAP HH compliance, the EPA is proposing that if reporters elect to use ProMax, they would be required to use version 5.0 or above.

As stated above, the EPA indicated in the referenced NESHAP HH ProMax approval that ProMax emissions results may be more conservative than emissions calculated using GLYCalc. In order to assess potential emissions changes between reporting years, the EPA is also proposing add a new provision under 40 CFR 98.236(e)(1)(xviii) to request reporting of the modeling software used to calculate emissions for each dehydrator unit using Calculation Method 1. We expect these proposed amendments would improve the quality of the data collected, consistent with section II.B of this preamble.

4. Calculation Method 1 Reporting

The EPA has reviewed the subpart W glycol dehydrator data and reporting requirements in existing 40 CFR 98.236(e) and has made a preliminary determination that additional information would help to more accurately characterize emissions from glycol dehydrators using Calculation Method 1. The EPA is proposing under 40 CFR 98.236(e) to require separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. These vents often use different control techniques, so requiring the emissions and applicable controls from these vents to be reported separately would ensure that emissions are more accurately characterized. The proposed data elements are included in the output files from the modeling software used for glycol dehydrators and therefore, this provision is not expected to be difficult for reporters to implement. We expect these proposed amendments would improve the quality of the data collected, consistent with section II.C of this preamble.[78]

[76] BRE Promax® software available from BRE website (*https://www.bre.com/*).

[77] Letter from Steffan Johnson, Group Leader, Measurement Technology Group, U.S. EPA Office of Air Quality Planning and Standards, to Josh Ravichandran, Bryan Research & Engineering, LLC, Re: Response to request for broad source category-wide approval for use of Bryan Research & Engineering's process simulation software, ProMax® (ProMax) in lieu of the GRI–GLYCalc™ software (GLYCalc) for modeling glycol dehydration unit emissions in demonstrating compliance with 40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Gas Production Facilities (Subpart HH). March 31, 2022. Available at *https://www.epa.gov/system/files/documents/2022-03/ravichandran-bre-promax-alt-final_147_signed.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[78] In the 2022 Proposed Rule, the EPA proposed to add several new reporting requirements for Calculation Method 1 glycol dehydrators under 40 CFR 98.236(e)(1) in an effort to find a potential correlation between dehydrator emissions and operating parameters. However, after consideration of comments received on the 2022 Proposed Rule, we have decided not to propose these additional elements in this proposal.

In the 2022 Proposed Rule, the EPA proposed to collect additional information on Calculation Method 1 glycol dehydrators under 40 CFR 98.236(e)(1) in an effort to derive a correlation between vent flow rate, absorbent circulation rate, and glycol pump type. Comments on the 2022 Proposed Rule indicated that this additional information request would be unnecessarily burdensome to reporters. Therefore, we are not proposing the reporting of additional data elements for this purpose in this proposal.

5. Calculation Method 2 for Glycol Dehydrators

As noted in section III.F.3 of this preamble, for glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per existing 40 CFR 98.233(e)(2) and report emissions per existing 40 CFR 98.236(e)(2). Under these current requirements, the count of glycol dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day could include dehydrators with annual average daily natural gas throughput of 0 MMscf per day (*i.e.*, glycol dehydrators that were not operated during the reporting year). As a result, some annual reports include a nonzero count of dehydrators per existing 40 CFR 98.236(e)(2)(i) without any corresponding CO_2 and CH_4 emissions. In these cases, it is not clear if the reporter did not report emissions because emissions are not expected, the emissions data were inadvertently omitted, or the nonzero count represents the total count of all dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day, including those that were not in use.

Therefore, the EPA is proposing to clarify in 40 CFR 98.233(e)(2) that the dehydrators for which emissions are calculated should be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day (*i.e.*, the count should not include dehydrators that did not operate during the year). Similarly, the EPA is proposing to clarify in 40 CFR 98.236(e)(2) introductory text that the count of dehydrators in existing 40 CFR 98.236(e)(2)(i) (proposed 40 CFR 98.236(e)(2)(ii)) should also be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day. These proposed amendments are expected to improve implementation and verification of reported data, consistent with section III.C of this preamble.

Additionally, the EPA is proposing edits to the existing reporting requirements in current 40 CFR 98.236(e)(2). Specifically, we are proposing to revise the data collected under current 40 CFR 98.236(e)(2)(iii) (proposed 40 CFR 98.236(e)(2)(iv)) to emphasize the original intent of the rule. Currently, the requirement is to report whether any Calculation Method 2 dehydrator emissions are routed to a control device other than a vapor recovery system or a flare or regenerator firebox/fire tubes (and if so, the type of control device(s) and count of units routing to each control). We are proposing to specifically state that the reporting of ''other'' control devices should only include control devices that reduce CO_2 and/or CH_4 emissions. This proposed revision would allow the EPA to verify the expected reductions in vented CO_2 and/or CH_4 emissions due to the use of the control device. This proposed amendment is expected to improve implementation and verification of reported data, consistent with section III.C of this preamble.

6. Desiccant Dehydrators

Subpart W requires reporting of desiccant dehydrators as a subcategory of dehydrator vents. The data required to be reported for desiccant dehydrators is consistent with the information that is reported for Calculation Method 2 for small glycol dehydrators: the total number of desiccant dehydrator units, whether any emissions from Calculation Method 3 units were routed to a vapor recovery system, flare, or other control (and if so, the count of units utilizing each of those controls), and the vented and/or combusted emissions from desiccant dehydrators. In June 2022, the EPA proposed to remove the reporting of desiccant dehydrators; however, as described in section II.B of this preamble, CAA section 136(h) directs the EPA to ensure that reporting under subpart W reflects total CH_4 emissions, and we are no longer proposing to remove this source. Instead, to better implement and verify the desiccant dehydrator data reported under subpart W (consistent with section II.C of this preamble), the EPA is proposing several updates to the current desiccant dehydrator reporting requirements of 40 CFR 98.236(e)(3).

Specifically, we are proposing to remove the cross-references from 40 CFR 98.236(e)(3) to 40 CFR 98.236(e)(2)(i) through (iv) and instead include all of the applicable reporting requirements from current 40 CFR 98.236(e)(2)(i) through (iv) for Calculation Method 2 glycol dehydrators as reporting requirements for Calculation Method 3 desiccant dehydrators under 40 CFR 98.236(e)(3). Currently, the language in 40 CFR 98.236(e)(3)(i) simply states that the same information that is included under 40 CFR 98.236(e)(2)(i) through (iv) should be reported for dehydrators that use desiccant. While we acknowledge that the current language has been correctly interpreted by reporters as-is, replicating the requirements under 40 CFR 98.236(e)(3) would make the rule easier to follow and allow the EPA to further clarify the required reporting data elements for desiccant dehydrators. Additionally, the EPA is proposing to specify that only desiccant dehydrators that were opened during the reporting year should be included in the total number of desiccant dehydrators at the facility under proposed 40 CFR 98.236(e)(3)(ii). This revision would align the reported count of desiccant dehydrators with the applicability of Calculation Method 3 methodology, which requires facilities to calculate emissions from the amount of gas vented from vessels when they are depressurized and opened for the desiccant refilling process. Also, we are proposing to require reporting of the total volume of all opened desiccant dehydrator vessels and the total number of desiccant dehydrator openings in the calendar year as new data elements under proposed 40 CFR 98.236(e)(3)(iii) and (iv), respectively. These data elements are inputs into equation W–6 and should, therefore, be readily available to facilities. With the change to reported number of desiccant dehydrators under proposed 40 CFR 98.233(e)(3)(ii) and the proposed addition of the two new data elements for vessel volume and number of vessel openings, the EPA would be able to more effectively verify the reported desiccant dehydrator emissions from each facility.

The EPA is also proposing to revise the definitions of ''dehydrator'' and ''desiccant'' in 40 CFR 98.6 to conform with the inclusion of desiccant dehydrators in subpart W. Currently, the definition of ''dehydrator'' indicates that desiccant is an example of a liquid absorbent. Since desiccants are solid materials, we are proposing to remove desiccant from the list of example liquid absorbents and instead define dehydrators as devices that use either a liquid absorbent or a desiccant to remove water vapor from a natural gas stream. The current definition of ''dehydrator'' also indicates that the device is used to absorb water vapor.

However, since some desiccants work by adsorbing water, we are proposing to replace the word ''absorb'' with ''remove.'' The definition of ''desiccant'' indicates that desiccants ''include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material.'' We are proposing to add ''molecular sieves'' to the list of example desiccant because they are a common type of desiccant. Since the list of example desiccants is not meant to be exhaustive or all-inclusive, we are also proposing to replace the word ''including'' with ''including, but not limited to.'' With these changes, the proposed definition would clarify that desiccants ''include, but are not limited to, molecular sieves, activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material.'' We expect these proposed amendments would improve the overall quality and completeness of the emissions data collected by the GHGRP, consistent with section II.A of this preamble.

Consistent with the proposed revisions to the definition of ''desiccant'' under 40 CFR 98.6, the EPA is proposing to add two additional data elements to the desiccant dehydrator reporting requirements in 40 CFR 98.236(e)(3). We are proposing to require reporting of the count of opened desiccant dehydrators that used deliquescing desiccant (*e.g.*, calcium chloride or lithium chloride) and the count of opened desiccant dehydrators that used regenerative desiccant (*e.g.*, molecular sieves, activated alumina, or silica gel) present at the facility (proposed 40 CFR 98.236(e)(3)(ii)(B) and (C), respectively). As regenerative desiccant dehydrators are not opened as often as deliquescing desiccant dehydrators, the EPA would use this new data to verify large swings in desiccant dehydrator emissions year-to-year and to gain a better understanding of the distribution of emissions between the two types of desiccant dehydrators. These proposed amendments would improve verification of reported data and ensure accurate reporting of emissions, consistent with section II.C of this preamble.

H. Liquids Unloading

1. Selection of Calculation Method

Subpart W currently requires reporting of emissions from well venting for liquids unloading. Facilities currently calculate emissions using measured flow rates under Calculation Method 1 (40 CFR 98.233(f)(1)) or engineering equations under Calculation Method 2 for unloadings without plunger lifts (40 CFR 98.233(f)(2)) and Calculation Method 3 for unloadings with plunger lifts (40 CFR 98.233(f)(3)). As noted in the preamble to the NSPS OOOOb supplemental proposal, facilities can face operational and safety issues managing liquids unloading with the EPA noting in the preamble that there could be situations where ''it is technically infeasible or not safe to perform well liquids with zero emissions unloadings'' (87 FR 74781, December 6, 2022). The EPA believes these safety and operational issues can possibly extend to taking measurements at wells with liquids unloading. Therefore, the EPA is proposing to continue providing reporters the option to use Calculation Methods 2 and 3 to calculate emissions from liquids unloading. Both equations rely on well-specific data, including well depth, tubing or casing diameter, and the flow line rate of gas, to calculate well-level emissions. However, consistent with section II.B of this preamble, the EPA is proposing that reporters with liquids unloadings must calculate emissions from unloadings for each well at least once every 3 consecutive calendar years or more frequently using Calculation Method 1 to ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading events.

To implement this change, the EPA is proposing to amend the introductory text in 40 CFR 98.233(f) to add the requirement that reporters must use Calculation Method 1 to calculate emissions from well venting for liquids unloading every 3 consecutive calendar years or more frequently. Calculation Method 1 currently requires reporters to install a recording flow meter on the vent line used to vent gas from the well to a separator or atmospheric tank and measure the flow rate of the unloading events. The reporter must measure flow rates at one or more wells in each sub-basin combination (sub-basin/plunger lift indicator/automated/manual indicator) where wells are subject to liquids unloading events. The average measured flow rate in standard cubic feet per hour is then applied to each well with unloadings in the same sub-basin combination for the time in hours during the year the well is unloaded. To support implementation of this requirement, the EPA is proposing to add 40 CFR 98.236(f)(2)(xi)(D) and 98.236(f)(2)(xii)(D) to require reporters to report the most recent calendar year Calculation Method 1 was used to calculate emissions from unloadings for the same sub-basin combination.

2. Reporting for Calculation Methods 2 and 3

Under the current reporting requirements of 40 CFR 98.236(f), facilities must report whether plunger lifts were used when using Calculation Method 1 and must report the data elements used in equations W–7A and W–7B. For Calculation Methods 2 and 3, however, reporters currently only report a subset of the data elements used to calculate emissions in equations W–8 and W–9. Specifically, for Calculation Methods 2 and 3, reporters must provide a plunger lift indicator (*i.e.*, whether plunger lifts were used), total number of wells with well venting for liquids unloading, the total number of unloading events, and the casing diameter (Calculation Method 2) or the tubing diameter (Calculation Method 3).

In a 2019 study, Zaimes *et al.*[79] evaluated various liquid unloading scenarios, and the results indicated that differentiating emissions only on the basis of type of unloading (plunger or non-plunger lift) may not accurately assess emissions from this source. In particular, Zaimes *et al.* noted that type of unloading should be further differentiated for plunger lift unloadings between automated and manual unloadings, suggesting further granularity is necessary to properly characterize emissions. In particular, there could be significant differences in the number and duration of unloadings and, hence, differences in emissions between manual and automated plunger lift unloadings and liquids unloading emissions. A manual unloading occurs when field personnel attend to the well at the well-pad, for example, to manually plunge a well at the site using a rig or other method, to open a valve to direct flow to an atmospheric tank to clear the well, or to manually shut-in the well to allow pressure to build in the well-bore. Manual unloadings may be performed on a routine schedule or on ''as needed'' basis. An automated unloading is performed without manual interference. Examples of an automated unloading include a timing and/or pressure device used to optimize intermittent shut-in of the well before liquids choke off gas flow or to open and close valves, continually operating equipment that does not require presence of an operator such as rod pumping units, automated and unmanned plunger lifts, or other

[79] Zaimes, G.G. *et al.* ''Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading.'' *Environ. Sci. Technol.* 2019, 53, 4619–4629. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

unloading activities that do not entail a physical presence at the well-pad.

The Zaimes *et al.* study did not evaluate manual and automated non-plunger lift unloadings separately, but further differentiating non-plunger lift unloadings between manual and automated unloadings in subpart W could also improve data quality. Correspondence with reporters via e-GGRT since subpart W reporting for the onshore production segment began in 2011 indicates potentially meaningful differences in the number of unloadings and emissions for manual versus automated non-plunger lift unloadings. When the EPA finalized the calculation methods and reporting requirements for well venting for liquids unloading, the reporting requirements did not differentiate between manual and automated non-plunger lift unloadings. However, reporters have clearly affirmed the use of automated non-plunger lift unloadings in response to multiple inquiries the EPA has made as part of the annual report verification process.

In addition, there are several data elements used to calculate emissions from liquids unloading in equations W–8 and W–9 for Calculation Methods 2 and 3 that are not currently required to be provided. Specifically, reporters do not report well depth (Calculation Method 2) or tubing depth (Calculation Method 3), the average flow-line rate of gas, the hours that wells are left open to the atmosphere during unloading events, and the shut-in, surface or casing pressure (Calculation Method 2) or the flow-line pressure (Calculation Method 3). Requiring reporting of these data elements would improve verification of annual reports to the GHGRP and would allow the EPA and the public to replicate calculations and more confidently confirm reported calculated emissions than is currently possible.

The EPA is, therefore, proposing to revise the reporting requirements in 40 CFR 98.236(f)(1) and (2) to require reporters to include the following data elements, consistent with section II.C of this preamble. In 40 CFR 98.236(f)(1), for Calculation Method 1, the EPA is proposing that reporters would identify the type of unloading as an automated or manual unloading in addition to identifying whether the unloading is a plunger lift or non-plunger lift unloading. We are also proposing in 40 CFR 98.236(f)(1) that reporters would report emissions by unloading type combination (with or without plunger lifts, automated or manual unloading). In addition, for each individual Calculation Method 1 well that was tested during the year, we are proposing that reporters would specify the type of unloading as automated or manual unloading under 40 CFR 98.236(f)(1)(xi)(F) or 40 CFR 98.236(f)(1)(xii)(F), as applicable.

For non-plunger lift unloadings that use Calculation Method 2 in 40 CFR 98.233(f)(2), the EPA is proposing in 40 CFR 98.236(f)(2) that reporters would identify the type of non-plunger lift unloading as automated or manual non-plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type combination. In addition, for each well with non-plunger lift unloadings, the EPA is proposing to revise and add requirements in existing 40 CFR 98.236(f)(2)(ix) (proposed 40 CFR 98.236(f)(2)(xi) in this proposed rule) to report the well depth for each well (WD_p) and the shut-in pressure, casing pressure or surface pressure for each well, (SP_p). Reporters would continue to report the internal casing diameter (CD_p) as is currently required for non-plunger lift unloadings.

For plunger lift unloadings that use Calculation Method 3 in 40 CFR 98.233(f)(3), the EPA is proposing in 40 CFR 98.236(f)(2) that reporters would identify the type of plunger lift unloading as automated or manual plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type combination. In addition, for all each well with plunger lift unloadings, the EPA is proposing to revise and add requirements in existing 40 CFR 98.236(f)(2)(x) (proposed 40 CFR 98.236(f)(2)(xii) in this proposed rule) to report the tubing depth (WD_p) and the flow-line pressure for each well in the sub-basin (SP_p). Reporters would continue to report the internal tubing diameter (TD_p) as is currently required for plunger lift unloadings.

Finally, for each well with unloadings that uses Calculation Method 2 or 3, the EPA is proposing to add new requirements, as proposed 40 CFR 98.236(f)(2)(ix) and (x), to report the flow-line rate of gas (SFR_p) and the cumulative number of hours that the well is left open to the atmosphere during unloading events ($HR_{p,q}$), respectively.

To encourage accurate classification of manual and automated unloadings for all calculation methods, the EPA is proposing to add new terms in 40 CFR 98.238 for ''Manual liquids unloading'' and ''Automated liquids unloading.'' The terms are proposed to be defined consistent with the descriptions provided earlier in this section of this preamble.

3. Other Clarifying Amendments

The EPA is proposing an additional amendment to add clarity for reporters with liquids unloadings. The EPA is proposing to specify in the introductory text for 40 CFR 98.233(f) that calculation of emissions from unloading events is required only when the well is unloaded to the atmosphere or to a control device. The EPA is proposing this change because these unloadings are the events that result in emissions of GHG to the atmosphere. The proposed change, consistent with sections II.C and II.D of this preamble, is intended to provide clarity to reporters while also ensuring that the EPA continues to receive accurate and relevant data.

I. Gas Well Completions and Workovers With Hydraulic Fracturing

Reporters currently may use equation W–10A or W–10B to calculate emissions from gas well completions and workovers with hydraulic fracturing. Equation W–10A is used to calculate emissions from wells using inputs obtained from a representative sample of wells within a sub-basin and the ratio of the gas flowback rate to the production flow rate, and equation W–10B is used to calculate emissions using inputs obtained from all wells within a sub-basin and the flow rate and flow volume of the gas vented or flared. In addition, reporters must use Calculation Method 1 or Calculation Method 2 in existing 40 CFR 98.233(g)(1) for calculating inputs to equations W–12A and W–12B if using equation W–10A. Calculation Method 1 relies on direct measurement of gas flow rate during flowback to develop calculation inputs whereas Calculation Method 2 uses an engineering equation to produce a calculated flowback. Specifically, Calculation Method 2 uses the measured gas pressure differential across the well choke to estimate gas flow rate for natural gas well completions and workovers with hydraulic fracturing. It is, therefore, often referred to as the ''Choke Flow'' equation. The Choke Flow equation is only available for hydraulically fractured natural gas well completions and workovers. It cannot be used for hydraulically fractured oil well completions and workovers.

The majority of onshore production facilities with hydraulically fractured completions and workovers use equation W–10B to calculate emissions. In RY2021, 118 onshore production facilities reported 2418 hydraulically fractured gas well completions or workovers. Only 15 of those facilities used equation W–10A for emissions calculations for 385 gas well completions or workovers. It is unknown what percentage of those facilities use Calculation Method 2, as the calculation methodology is not currently reported.

Consistent with section II.B of this preamble, the EPA is proposing to retain equations W–10A and W–10B, but is proposing to remove the option in 40 CFR 98.233(g)(1) for reporters to use Calculation Method 2, the Choke Flow equation, when using equation W–10A. The EPA believes that measurement of back flow rates is standard practice in the onshore production segment, whether through measurement of every well completion or workover or through measurement of a representative well or workover. Moreover, this is supported by the large number of reporters using equation W–10B compared with equation W–10A. The EPA believes this proposal would improve reporting of emissions from hydraulically fractured gas well completions and workovers while impacting very few reporters due to the small number of reporters using equation W–10A. The EPA understands that some reporters may be concerned that there could be situations where direct measurement is not possible for technical, operational or safety reasons; however, subpart W provides requirements for use of missing data procedures as specified in 40 CFR 98.235. The EPA is requesting comment on whether we should retain Calculation Method 2 for gas well completions and workovers with hydraulic fracturing. However, if the EPA retains Calculation Method 2 following consideration of public comment on this proposed rulemaking, the EPA expects we would also amend the reporting requirements in the final rulemaking to improve data quality and transparency. Specifically, if Calculation Method 2 is retained, the EPA expects we would add a new reporting requirement in 40 CFR 98.236(g) for reporters that use equation W–10A to indicate whether the backflow rate for the representative well was determined using Calculation Method 1 or Calculation Method 2.

J. Blowdown Vent Stacks

1. Reporting Equipment Categories for Pipelines

Subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). Stakeholders have indicated through correspondence with the EPA via e-GGRT and the GHGRP Help Desk that the descriptions of the ''facility piping'' and ''pipeline venting'' categories in 40 CFR 98.233(i)(2) as it is currently written reference ''distribution'' pipelines but compressor stations are generally not associated with distribution pipelines. Therefore, the EPA is proposing to revise the descriptions of the facility piping and pipeline venting categories in 40 CFR 98.233(i)(2) to reflect the EPA's intent regarding which equipment or event type category is appropriate for each blowdown, consistent with section II.D of this preamble. Our intent is that the ''facility piping'' equipment category is limited to unique physical volumes of piping (*i.e.*, piping between isolation valves) that are located entirely within the facility boundary. In contrast, the intent for the ''pipeline venting'' equipment category is that a portion of the unique physical volume of pipeline is located outside the facility boundary and the remainder, including the blowdown vent stack, is located within the facility boundary. The proposed revisions to the equipment type descriptions would clarify these distinctions. Additionally, we are proposing to remove the reference to ''distribution'' pipelines in the description of these two categories because we did not intend to limit the pipeline venting category to unique physical volumes that include such pipelines. We agree with the industry stakeholders who have indicated that facilities subject to the blowdown vent stack reporting requirements typically are connected to other pipelines such as gathering pipelines or transmission pipelines, and on-site blowdowns from sections of these pipelines should be reported. Finally, we note that for the ''facility piping'' equipment category and the ''pipeline venting'' equipment category, the existing phrase ''located within a facility boundary'' in the descriptions of those categories generally refers to being part of the facility as defined by the existing provisions of subpart A or subpart W, as applicable, and we are not proposing to change that portion of those descriptions. In other words, blowdowns from unique physical volumes of gathering pipeline that are entirely considered to be part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238 would be assigned to the ''facility piping'' equipment category. The ''pipeline venting'' equipment category would only apply if the unique physical volume includes some sections of gathering pipelines that are not part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238.

2. Blowdown Equipment Types

As noted in section III.J.1 of this preamble, subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). When the Onshore Natural Gas Transmission Pipeline industry segment was added to subpart W in 2015, after considering public comments that indicated that the existing equipment or event types were not appropriate for the new segment, the EPA developed new equipment or event types that apply only for the Onshore Natural Gas Transmission Pipeline industry segment (80 FR 64275, October 22, 2015). The new equipment or event types were added to the introductory paragraph of 40 CFR 98.233(i)(2), where the existing equipment or event types were already located, resulting in a complex introductory paragraph. These changes also resulted in identical third and last sentences in 40 CFR 98.233(i)(2) that currently read as follows: ''If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.''

The EPA is proposing, consistent with section II.D of this preamble, to move the listings of event types and the apportioning provisions to a new 40 CFR 98.233(i)(2)(iv) so that the introductory paragraph in 40 CFR 98.233(i)(2) would be more concise and provide clearer information regarding which requirements are applicable for each blowdown. Proposed 40 CFR 98.233(i)(2)(iv) includes separate paragraphs for each set of equipment and event type categories and would also provide clearer information regarding the applicable requirements for each industry segment.

3. Blowdown Temperature and Pressure

In the 2015 amendments to subpart W (80 FR 64262, October 22, 2015), the EPA added the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment and the Onshore Natural Gas Transmission Pipeline industry segment and specified that both industry segments are required to report emissions from blowdown vents. Stakeholders representing the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment provided comments on the proposed rule stating that the proposed definition of facility would make equipment geographically dispersed, and blowdowns may occur without personnel on-site or nearby, which would make it difficult to collect the information needed to calculate emissions from each blowdown (80 FR 64271, October 22, 2015). After considering those comments, the EPA also specified in the final amendments to equation W–14A that for emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the actual temperature and actual pressure.

Since that time, the EPA has received questions through the GHGRP Help Desk indicating that facilities in the Onshore Natural Gas Transmission Pipeline industry segment also have unmanned blowdown vents. Given that a ''facility with respect to the onshore natural gas transmission pipeline segment'' is the total mileage of natural gas transmission pipelines owned and operated by an onshore natural gas transmission pipeline owner or operator, all of the blowdown vents at that facility would be outside the fenceline of a transmission compression station and would be geographically dispersed. The EPA considers it reasonable to assume that those blowdown vents may also be unmanned during an emergency blowdown, and thus it can similarly be difficult to collect the information needed to calculate emissions from each blowdown. Therefore, we are proposing to extend the provisions in equation W–14A of 40 CFR 98.233(i)(2)(i) that allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown to the Onshore Natural Gas Transmission Pipeline segment, which would align the requirements for the two geographically dispersed industry segments currently required to report blowdown vent stack emissions (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) and increase clarity of reporting requirements for Onshore Natural Gas Transmission Pipeline reporters, consistent with section II.D of this preamble. As described in section III.C.1 of this preamble, we are also proposing to allow use of engineering estimates to determine the temperature and pressure for emergency blowdowns in equation W–14A for the geographically dispersed industry segments that we are proposing would begin reporting emissions from blowdown vent stacks (Onshore Petroleum and Natural Gas Production and Natural Gas Distribution).

In addition, similar provisions to allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown were not added to equation W–14B of 40 CFR 98.233(i)(2)(i) in 2015 (80 FR 64262, October 22, 2015). We have reviewed this equation and have determined that this omission was inadvertent. Therefore, we are proposing to add provisions to equation W–14B of 40 CFR 98.233(i)(2)(i) to allow use of engineering estimates to determine the temperature and pressure of an emergency blowdown for both the geographically dispersed industry segments that currently report blowdown vent stack emissions (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) as well as the geographically dispersed industry segments that we are proposing would be required to begin reporting blowdown vent stack emissions as described in section III.C.1 of this preamble (Onshore Petroleum and Natural Gas Production and Natural Gas Distribution), consistent with equation W–14A.

K. Atmospheric Storage Tanks

Facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are currently required to report CO_2 and CH_4 emissions (and N_2O emissions when flared) from atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids (hereafter referred to as ''atmospheric storage tanks'').[80] Reporters with gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.*, stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day are required to calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as described in existing 40 CFR 98.233(j)(1) and (2), respectively. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, facilities must calculate annual CH_4 and CO_2 emissions using Calculation Method 2. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, reporters must currently use Calculation Method 3 as specified in existing 40 CFR 98.233(j)(3) to calculate annual CO_2 and CH_4 emissions.

1. Open Thief Hatches

The purpose of a thief hatch on an atmospheric storage tank is generally to allow access to the contents of the tank for sampling, gauging, and determining liquid levels. The thief hatch also works along with the vent valve to maintain safe tank operating pressures. The EPA previously evaluated emissions from atmospheric storage tanks as part of the 2016 amendments to subpart W (81 FR 86500, November 30, 2016) and determined that the subpart W calculation methodology in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on atmospheric storage tanks in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. The subpart W calculation methodologies for controlled atmospheric storage tanks include procedures for determining emissions from storage tanks with a vapor recovery system (existing 40 CFR 98.233(j)(4)) and storage tanks with a flare (existing 40 CFR 98.233(j)(5)). The procedure for determining emissions from a tank with a vapor recovery system instructs reporters to adjust the storage tank emissions downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data (existing 40 CFR 98.233(j)(4)(i)). The procedure for determining emissions from an atmospheric storage tank with a flare references 40 CFR 98.233(n), which currently instructs reporters to use engineering calculations based on process knowledge, company records, and best available data to determine the flow to the flare if the flare does not have a continuous flow measurement device. If a reporter sees emissions from a thief hatch or other opening on a controlled atmospheric storage tank during an equipment leak survey

[80] As described in section III.C.3 of this preamble, the EPA is proposing to revise the source type in 40 CFR 98.233(j) from the current name of ''onshore production and onshore petroleum and natural gas gathering and boosting storage tanks'' to ''hydrocarbon liquids and produced water storage tanks'' to reflect the proposal to require reporting of storage tank emissions from additional industry segments as well as to reflect the proposed addition of reporting for produced water storage tanks. When used to describe proposed amendments in this section, the general term ''atmospheric storage tanks'' applies to the group of hydrocarbon liquids and produced water storage tanks that would be reporting emissions if these proposed amendments are finalized.

conducted using OGI, the reporter should consider that information as part of the ''best available data'' used to calculate emissions from that storage tank.

However, it appears that reporters may not be accurately accounting for emissions from open thief hatches on atmospheric storage tanks, as many reporters claim 100 percent capture efficiency from vapor recovery systems and flares. In order to emphasize the original intent of the rule and ensure the accuracy of reported data, the EPA is proposing several clarifying edits to 40 CFR 98.233(j)(4) and (5) (which, as described in section III.K.3 of this preamble, would be combined in proposed 40 CFR 98.233(j)(4)), consistent with sections II.B and II.C of this preamble. We are proposing to specifically state that emissions during times of reduced capture efficiency are required to be evaluated to determine if adjustments are needed to the calculated recovered mass from vapor recovery units or total emissions vented to atmosphere from tanks. Reduced capture efficiency may occur during periods when the control device is not operating or is bypassed when the control device is operating, such as open thief hatches. The emissions that are not captured by a vapor recovery system or sent to a flare must be considered when calculating emissions from atmospheric storage tanks vented directly to the atmosphere using Calculation Methods 1, 2, or 3.

Further, we are proposing to provide a calculation methodology for determining reduced capture efficiencies when a control device is in use but a thief hatch is not properly seated or closed. We are proposing to revise existing 40 CFR 98.233(j) to require facilities to assume that no emissions are captured by the control device (0 percent capture efficiency) when the thief hatch on a tank is open or not properly seated. As described above, emissions during this time would be reported as vented directly to the atmosphere as determined using Calculation Methods 1, 2, or 3. Additionally, in order to accurately quantify the time period that emissions are vented to atmosphere from an open or not properly seated thief hatch, consistent with section II.B of this preamble, the EPA is proposing in 40 CFR 98.233(j)(7) to require either the use of a thief hatch sensor, if present and operating, or if a thief hatch sensor is not present and operating, visual inspection of the tank to monitor the thief hatch. We are proposing that if a thief hatch sensor is present and operating on the tank, sensor data must be used to inform the periods of time that a thief hatch is open or not properly seated. The thief hatch sensor must be capable of transmitting and logging data whenever a thief hatch is open or not properly seated and when the thief hatch is subsequently closed. Visual inspections would be required once per calendar year, at a minimum, if a thief hatch sensor is not present and operating. If the thief hatch is required to be monitored as a fugitive emissions component to comply with NSPS OOOOb or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62, we are proposing that visual inspections must be conducted at least as frequent as the required visual, audible, or olfactory fugitive emissions components surveys described in NSPS OOOOb or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62, or annually (whichever is more frequent). Similar to the provisions of 40 CFR 98.233(q), if one visual inspection is conducted in the calendar year and an open or not properly seated thief hatch is identified, the reporter would be required to assume that the thief hatch had been open for the entire calendar year. If multiple visual inspections are conducted in the calendar year and an open or not properly seated thief hatch is identified, the reporter would be required to assume that the thief hatch had been open since the preceding visual inspection (or the beginning of the year if the inspection was the first performed in a calendar year) through the date of the visual inspection (or the end of the year if the inspection was the last performed in a calendar year). As discussed in the TSD for the 2016 amendments to subpart W, we determined that this methodology provides an accurate quantification of emissions and it is consistent with the timeframe required for subpart W annual reports.[81] However, we are requesting comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. In this scenario, if the reporter can identify the start date and it spans reporting years, then that reporter would have to report the vented tank emissions from an open thief hatch that occurred in each reporting year and, if necessary, revise reports for the previous reporting year. The EPA is also seeking comment on alternative methodologies for quantifying the time that a thief hatch is left open or not properly seated in lieu of a required visual inspection.

The EPA is also proposing revisions to the atmospheric storage tank reporting requirements in 40 CFR 98.236(j) with regard to open thief hatches. Specifically, the EPA is proposing to require reporting of the number of controlled atmospheric storage tanks with open or not properly seated thief hatches within the reporting year, as well as the total volume of gas vented through the open or not properly seated thief hatches, for all calculation methods. With these new reporting elements, the EPA seeks to quantify the impact of open thief hatches on atmospheric storage tanks and enhance the overall quality of the data collected under the GHGRP, consistent with section II.C of this preamble.

Stakeholders have voiced concerns through the GHGRP Help Desk regarding the potential for double counting of tank thief hatch emissions under 40 CFR 98.236(j), (q) and (r). The EPA has previously confirmed that there is no potential for double counting thief hatches in the methodologies provided in 40 CFR 98.233(q) and 40 CFR 98.233(r), and we have also confirmed that there is no potential for double counting thief hatches based on the proposed revisions to 40 CFR 98.236(j), (q) and (r). When determining leaks by population count per 40 CFR 98.233(r), the EPA is proposing updated major equipment emission factors in existing Table W–1A (proposed Table W–1) that were developed using Rutherford *et al.* (2021). Population emission factors are presented by major equipment, which includes tanks—leaks; however, the major equipment indicating venting emissions (*e.g.*, tanks—unintentional vents) were not included. For equipment leak surveys per 40 CFR 98.233(q), existing Table W–1E (proposed Table W–2) references 40 CFR 98.232(c)(21) and (j)(10) for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, respectively. These provisions, which describe the list of components to be surveyed for equipment leaks, specifically state that thief hatches or other openings on a storage vessel should not be considered an ''other component.'' As such, we confirm that the proposed thief hatch emissions reporting requirements in 40 CFR 98.236(j) would not overlap with the equipment leak emission reporting requirements in 40 CFR 98.236(q) and (r). Also, we confirm that the proposed thief hatch emissions reporting requirements would not overlap with

[81] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.* November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

emissions reporting in 40 CFR 98.236(y). As stated in section III.B of this preamble, only thief hatch emissions that exceed the emissions estimated under 40 CFR 98.233(j) by 250 $mtCO_2e$ or more, or 100 kg/hr of CH_4 or more, would be included in the calculation and reporting requirements for ''other large release events.''

The EPA is aware that there are circumstances other than open or not properly seated thief hatches in which the capture efficiency of the control device(s) for atmospheric storage tanks is reduced. These circumstances include, but are not limited to, when the control device is bypassed due to an open pressure relief device or when the atmospheric storage tank covers and closed vent systems have openings that allow emissions to vent directly to atmosphere. We are proposing in 40 CFR 98.233(j)(4)(i)(D) to require facilities to account for time periods of reduced capture efficiency from causes other than open or not properly seated thief hatches when determining total emissions vented directly to atmosphere based on best available data. However, we are requesting comment on methodologies other than best available data for identifying and quantifying time periods of reduced capture efficiency in these situations. For example, the EPA is requesting comment on the prevalence of pressure monitoring systems on atmospheric storage tanks, how pressure monitoring systems can be used to identify and determine the duration of periods of reduced capture efficiency due to open pressure relief devices, and the cost of those pressure monitoring systems.

2. Malfunctioning Dump Valves

For Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities with atmospheric storage tank emissions calculated using Calculation Method 1 (40 CFR 98.233(j)(1)) or Calculation Method 2 (40 CFR 98.233(j)(2)), reporters must also follow the procedures in current 40 CFR 98.233(j)(6) (proposed 40 CFR 98.233(j)(5)) and use equation W–16 to calculate emissions from occurrences of gas-liquid separator dump valves not closing properly. Equation W–16 estimates the annual volumetric GHG emissions at standard conditions from each storage tank resulting from the malfunctioning dump valve on the gas-liquid separator using a correction factor, the total time the dump valve did not close properly in the calendar year, and the hourly storage tank emissions. Per the definition of the variable ''E_n'' in equation W–16, the input hourly storage tank emissions should be those calculated using Calculation Methods 1 or 2 and should be adjusted downward by the magnitude of emissions recovered using a vapor recovery system, if applicable. The EPA is proposing to revise the equation variables (particularly the subscripts) in equation W–16 to clarify the intent of this equation. We are proposing to revise the variable ''E_n'' to ''$E_{s,i}$'' to further clarify that these are the volumetric atmospheric storage tank emissions determined using the procedures in 40 CFR 98.233(j)(1), (2), and (4). We are also proposing to replace the ''n'' and ''o'' subscripts in the other variables with a ''dv'' subscript to indicate that these are the emissions from periods when the gas-liquid separator dump valves were not closed properly and that the emissions from these periods should be added to the emissions determined using the procedures in 40 CFR 98.233(j)(1), (2), and (4).

One of the inputs to equation W–16 is the total time the dump valve did not close properly in the calendar year (T_n). Currently, T_n may be estimated based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position. In order to improve the quality of the open dump valve emissions data collected, consistent with section II.C of this preamble, the EPA is proposing to formalize the requirement to perform routine visual inspections of separator dump valves to determine if the valve is stuck in an open position, thus allowing gas carry-through to the controlled tank(s).

The EPA is proposing to revise the current provisions in 40 CFR 98.233(j)(6) (which is proposed 40 CFR 98.233(j)(5)) to require visual inspection of the gas-liquid separator and determine if the liquid dump valve is stuck in an open or partially open position. Incorporating this proposed monitoring requirement would result in a more realistic time estimate being used in equation W–16 and thus, more accurate emissions reporting, consistent with section II.B of this preamble. Visual inspections would be required once per calendar year, at a minimum. Similar to the provisions of 40 CFR 98.233(q) and the proposed section 40 CFR 98.233(j)(7), if one visual inspection is conducted in the calendar year and a stuck dump valve is identified, the reporter would be required to assume that the dump valve had been stuck open for the entire calendar year. If multiple visual inspections are conducted in the calendar year and a stuck dump valve is identified, the reporter would be required to assume that the dump valve had been stuck open since the preceding visual inspection (or the beginning of the year if the inspection was the first performed in a calendar year) through the date of the visual inspection (or the end of the year if the inspection was the last performed in a calendar year). As discussed in the TSD for the 2016 amendments to subpart W, we determined that this methodology provides an accurate quantification of emissions and it is consistent with the timeframe required for subpart W annual reports.[82] We are requesting comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. In this scenario, if the reporter can identify the start date and it spans reporting years, then that reporter would have to report the vented tank emissions from an open thief hatch that occurred in each reporting year and, if necessary, revise reports for the previous reporting year.

3. Applicability and Selection of Appropriate Calculation Methodologies for Atmospheric Storage Tanks

When determining the applicability of the different calculation methodologies described in existing 40 CFR 98.233(j), reporters must calculate their annual average daily throughput to determine whether flow of hydrocarbon liquids through the gas-liquid separator, well, or non-separator equipment is greater than or equal to 10 barrels per day. Through the GHGRP Help Desk and correspondence with the EPA via e-GGRT, it appears that reporters may be misinterpreting how hydrocarbon liquid throughputs from gas-liquid separators should be determined. Specifically, reporters appear to have differing conclusions regarding whether the throughput determination should be based on flow into or out of the separator and whether days when the separator was not operating should be included when calculating the annual average. Therefore, we are proposing revisions to the introductory text of 40 CFR 98.233(j) to emphasize the original intent of how the hydrocarbon liquid throughputs should be determined. Specifically, we are proposing to add language that clearly states that the annual average daily throughput of hydrocarbon liquids should be based on

[82] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*. November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

flow out of the separator, well, or non-separator equipment determined over the actual days of operation. This amendment is expected to clarify the rule, consistent with II.D of this preamble and improve the quality of the data collected, consistent with section II.C of this preamble.

For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput greater than 0 barrels per day and less than 10 barrels per day, reporters currently use population emission factors and equation W–15 to calculate volumetric CO_2 and CH_4 emissions per Calculation Method 3 (40 CFR 98.233(j)(3)) and report emissions per 40 CFR 98.236(j)(2). However, facilities with hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput greater than or equal to 10 barrels per day are given the option to either model their tanks per Calculation Method 1 (40 CFR 98.233(j)(1)) or use a mass balance approach per Calculation Method 2 (40 CFR 98.233(j)(2)). Through the GHGRP Help Desk and correspondence with the EPA via e-GGRT, reporters have expressed the desire to use Calculation Methods 1 or 2 for reporting emissions from storage tanks currently required to use Calculation Method 3, as they stated that the population emission factors provided in 40 CFR 98.233(j)(3) are not always representative of their tanks' actual emissions. Calculation Methods 1 and 2 require unit-specific inputs, so it is reasonable to expect that they would result in more accurate emissions estimates for atmospheric storage tanks that have differing operating characteristics than those used to develop the Calculation Method 3 emission factors. Therefore, the EPA is proposing to amend the requirements in 40 CFR 98.233(j) to specify reporters may use Calculation Method 1, Calculation Method 2, or Calculation Method 3 when determining emissions from hydrocarbon liquids flowing to wells, gas-liquid separators, or non-separator equipment with throughput greater than 0 barrels per day and less than 10 barrels per day. We are also proposing to specify in 40 CFR 98.233(j) that if a reporter is required or elects to perform emissions modeling of an atmospheric storage tank consistent with the methodology outlined in 40 CFR 98.233(j)(1), they must use the results of the model for estimating emissions under 40 CFR 98.233(j). It is the EPA's intention with this proposal that if reporters conduct modeling for environmental compliance or reporting purposes, including but not limited to compliance with Federal or state regulations, air permit requirements, annual inventory reporting, or internal review, they would use those results for reporting under subpart W. Consistent revisions are also proposed for the reporting requirements in 40 CFR 98.236(j). These amendments are expected to improve the quality of the data collected and provide flexibility to reporters, consistent with section II.D of this preamble.

The current requirements in 40 CFR 98.233(j) require calculation of emissions from atmospheric pressure fixed roof storage tanks. As discussed in section III.C of this preamble, the EPA evaluated the sources included in present-day inventories of the oil and gas industry in comparison with sources covered in subpart W and is proposing to include additional sources in subpart W as a result of this evaluation. Based on a similar evaluation, we are proposing to remove the ''fixed roof'' language when referring to atmospheric pressure storage tanks subject to 40 CFR 98.233(j). This would expand the reporting of tank emissions to include floating roof tanks, which are a source included in the 2022 U.S. GHG Inventory for the petroleum industry. We are also proposing revisions to existing 40 CFR 98.236(j)(1)(x) and existing 40 CFR 98.236(j)(2)(i) to require separate reporting of the total count of fixed roof and floating roof tanks at the facility. To provide additional clarity for this proposed amendment, we are also proposing to revise all instances of ''storage tanks,'' ''atmospheric tanks,'' and ''tanks'' in 40 CFR 98.233(j) and 40 CFR 98.236(j) to instead use the term ''atmospheric pressure storage tanks.'' We are proposing to define an atmospheric pressure storage tank as ''a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.*, wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.'' We expect these proposed amendments would improve the overall quality and completeness of the emissions data collected by the GHGRP, consistent with section II.A of this preamble.

4. Controlled Atmospheric Storage Tanks

In correspondence with the EPA via e-GGRT, some reporters have asked the EPA for guidance regarding calculating emissions from atmospheric storage tanks that are routed to different control devices throughout the reporting year (*e.g.*, tanks that are routed to vapor recovery and subsequently vented to atmosphere or routed to a flare when the vapor recovery device is not operating). Given the proposed amendments to the calculation methodology and reporting of flare stack emissions (discussed in section III.N of this preamble), we are proposing to revise the methodologies for calculating emissions from tanks controlled by a vapor recovery system or a flare currently provided in 40 CFR 98.233(j)(4) and (5), respectively. The new language in proposed 40 CFR 98.233(j)(4)(i) provides a methodology for calculating emissions vented to atmosphere during periods of reduced capture efficiency of the vapor recovery system or flare (*e.g.*, when a thief hatch is open or not properly seated). The provisions of proposed 40 CFR 98.233(j)(4)(ii) would require facilities to use engineering estimates based on best available data to calculate recovered mass from vapor recovery systems, and also clarifies that reporters must take into account periods with reduced capture efficiency of the vapor recovery system (*e.g.*, when a thief hatch is open or not properly seated or when the vapor recovery system is down for maintenance) when calculating mass recovered. For flared atmospheric storage tank emissions, the proposed 40 CFR 98.233(j) provisions would direct reporters to the proposed methodologies in 40 CFR 98.233(n). By proposing these amendments, the EPA seeks to enhance the overall quality of the data collected under the GHGRP, consistent with section II.D of this preamble.

5. Calculation Methods 1 and 2 for Atmospheric Storage Tanks

Reporters with atmospheric storage tanks that calculate emissions using Calculation Method 1 are currently required to determine emissions using any standard simulation software package that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions from the atmospheric storage tank. According to current 40 CFR 98.233(j)(1), the information that must be used to characterize emissions include separator or non-separator equipment temperature and pressure, sales or stabilized hydrocarbon liquids API gravity, sales or stabilized hydrocarbon liquids production rate, ambient air temperature and pressure, and separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure. These parameters currently must be determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data. Consistent with section II.B of this preamble, we are proposing that the input parameters related to the hydrocarbon liquid stream that are used for the simulation software must be obtained by measurement.[83] Those parameters include separator or non-separator equipment temperature and pressure, sales or stabilized hydrocarbon liquids API gravity, sales or stabilized hydrocarbon liquids production rate, and separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure. We are proposing that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. We are not proposing to change the requirement that the other parameters must be determined for operating conditions based on engineering estimate and process knowledge.

We are also proposing that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this proposed change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year.

For reporters with atmospheric storage tanks that calculate emissions using Calculation Method 2, all CH_4 and CO_2 in solution are assumed to be emitted from hydrocarbon liquids. For flow to storage tanks after passing through a separator, the CH_4 and CO_2 in solution is determined by taking a sample of separator hydrocarbon liquids at separator pressure and temperature. However, for flow to atmospheric storage tanks direct from wells and flow to atmospheric storage tanks direct from non-separator equipment, facilities may only use either the latest compositional analysis already available at the facility or default liquid and gas compositions from modeling software programs to determine the CH_4 and CO_2 in solution; there is currently no requirement to take a representative sample during the calendar year. Consistent with these proposed amendments for atmospheric tanks with emissions calculated using Calculation Method 1, the EPA is proposing that the composition of the liquids flowing to all tanks with emissions calculated using Calculation Method 2 must be obtained by measurement, regardless of the source from which the liquids are supplied. We are proposing to remove the provisions of 40 CFR 98.233(j)(2)(ii) and (iii) that allowed for representative compositions to be used for tanks receiving liquids directly from wells or non-separator equipment. These amendments are expected to improve the accuracy of the data collected under the GHGRP, consistent with section II.B of this preamble.

Similar to the provision for dehydrators in 40 CFR 98.233(e)(1), subpart W currently provides two example software options, AspenTech HYSYS® or API 4697 E&P Tank, that meet the software requirements in 40 CFR 98.233(j)(1). Under the existing requirements, reporters are not limited using to these two software options when complying with 40 CFR 98.233(j)(1). However, many reporters have been using BRE's ProMax software to model their tank emissions. In RY2021, based on responses to 40 CFR 98.236(j)(1)(ii) (name of the software package used if using Calculation Method 1), 59 percent of facilities reporting emissions from Calculation Method 1 atmospheric storage tanks used ProMax as their modeling software, compared to 30 percent using API 4697 E&P Tank and 6 percent using AspenTech HYSYS®. Given the significant majority of reporters using ProMax, and considering our proposed addition and supporting rationale of ProMax to the list of example software options in 40 CFR 98.233(e)(1), we are proposing to add ProMax as an example software program for calculating atmospheric tank emissions per 40 CFR 98.233(j)(1). Consistent with the EPA's proposed revisions to 40 CFR 98.233(e)(1), the EPA is proposing to require ProMax version 5.0 or above. We expect these proposed amendments would improve the quality of the data collected, consistent with section II.C of this preamble.

Additionally, we are aware that several process simulation software options have the ability to model emissions from atmospheric storage tanks that are receiving hydrocarbon liquids directly from wells. As such, the EPA is proposing to amend 40 CFR 98.233(j) such that facilities with wells flowing directly to atmospheric storage tanks without passing through a separator may use either Calculation Method 1, Calculation Method 2, or, for wells, gas-liquid separators, or non-separator equipment with annual average daily throughput less than 10 barrels per day, Calculation Method 3. We are also proposing conforming edits within 40 CFR 98.233(j)(1) and (2) and 40 CFR 98.236(j)(1) to refer to parameters and requirements for wells flowing directly to atmospheric storage tanks. These proposed amendments are expected to improve the accuracy of reported emissions, consistent with section II.B of this preamble.

Stakeholders have indicated through correspondence with the EPA via e-GGRT and the GHGRP Help Desk that flash emissions from atmospheric storage tanks are often determined through laboratory measurement of separator liquid gas to oil ratio (GOR). This emission calculation methodology involves taking a pressurized sample of crude or condensate from an upstream vessel (separator or non-separator equipment) and flashing the sample in a laboratory. To do this, part of the sample is brought to sampling temperature and pressure conditions, while another portion of the sample is brought to storage tank temperature and pressure conditions. The amount of gas released per volume of oil generated is measured to estimate the GOR. The chemical composition of the flash gas is then analyzed and the CH_4 and CO_2 concentrations are determined. The GHG emissions can be estimated by multiplying the GOR by the crude oil or condensate throughput, and then applying the CH_4 and/or CO_2 composition to the total gas rate to estimate the CH_4 and/or CO_2 emissions from the atmospheric storage tank. The EPA has determined that this methodology does not meet the requirements of Calculation Method 1 (as the emissions are not calculated using a modeling software) or Calculation Method 2 (as the emissions are not calculated assuming that all the CH_4 and CO_2 in solution at separator temperature and pressure is emitted).

[83] As described in section III.C.3 of this preamble, the EPA is also proposing to expand the applicability of 40 CFR 98.233(j)(1) to include produced water tanks.

However, upon review of storage tank emissions calculation guidance from states such as Louisiana [84] and Texas,[85] it appears that companies may be performing this testing to meet state-level requirements. Additionally, this methodology is included in the 2021 API Compendium as an option for determining atmospheric storage tank emissions.

Therefore, we are seeking comment on adding laboratory measurement of the GOR from a pressurized liquid sample as a new emission calculation methodology for atmospheric storage tanks under 40 CFR 98.233(j). If this methodology were to be added to 40 CFR 98.233(j), we anticipate providing an equation that would multiply the measured GOR by the annual throughput of the hydrocarbon liquid stream to the atmospheric storage tank (in barrels per year) to obtain the annual volumetric flash gas emissions. The CO_2 and CH_4 emissions from the atmospheric storage tank would then be calculated using CO_2 and CH_4 flash gas concentrations determined from the laboratory analysis. Facilities utilizing this methodology would report all data elements required under 40 CFR 98.236(j)(1), consistent with the reporting for Calculation Methods 1 and 2. We would also require additional data elements associated specifically with this new calculation method, such as the annual average GOR and total days of operation of the atmospheric storage tank(s) at the facility, well-pad, or gathering and boosting site. We specifically request comment on the accuracy of this methodology for calculating GHG emissions (with emphasis on comparison with Calculation Method 1 modeling), as well as how extensive its use may be in the oil and gas industry.

6. Calculation Methods 1 and 2 Reporting

For facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2, 40 CFR 98.236(j)(1) currently requires reporting of counts of the total number of atmospheric storage tanks within the sub-basin or county (40 CFR 98.236(j)(1)(x)), the number of atmospheric storage tanks that are controlled by a vapor recovery system (40 CFR 98.236(j)(1)(xii)(A)), the number of atmospheric storage tanks that are controlled by a flare (40 CFR 98.236(j)(1)(xiv)(A)), and the number of atmospheric storage tanks that are not controlled by either a vapor recovery system or a flare (40 CFR 98.236(j)(1)(xiii)(A)).[86] Given the proposed amendments to require reporting of CO_2, CH_4, and N_2O emissions from atmospheric storage tanks controlled by a flare under 40 CFR 98.236(n) (discussed in section III.N of this preamble), the EPA is proposing to reorganize the reporting requirements in 40 CFR 98.236(j)(1) to collect each of these tank counts under 40 CFR 98.236(j)(1)(x)(A) through (F).[87] The EPA is also proposing to move the reporting of CO_2 and CH_4 vented emissions and recovered mass to paragraph 40 CFR 98.236(j)(1)(xi) through (xiv). With this reorganization of the emissions reporting requirements for atmospheric storage tanks, the EPA expects to improve verification of atmospheric storage tank emissions, consistent with section II.C of this preamble.

Additionally, the EPA is proposing to remove the requirement to report an estimate of the number of atmospheric storage tanks that are not on well-pads and that are receiving the facility's oil (existing 40 CFR 98.236(j)(1)(xi)), consistent with section II.C of this preamble. This reporting requirement is currently, and under the proposed rule would still be, redundant because all Onshore Petroleum and Natural Gas Production facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 must also report the total number of atmospheric storage tanks in the sub-basin per existing 40 CFR 98.236(j)(1)(x) (proposed to be revised to the total number of atmospheric storage tanks at the well-pad).

Under 40 CFR 98.236(j)(1)(vii) and (viii), reporters with atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 are currently required to provide the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas. Reporting of emissions and activity data for atmospheric storage tanks is aggregated at the sub-basin or county level under the current regulations, and the minimum and maximum flash gas concentrations were expected to provide the EPA with a broad characterization of the often-significant number of tanks reported for each sub-basin or county. However, through correspondence with reporters via e-GGRT, the EPA has found that the minimum and maximum flash gas concentrations do not accurately represent the majority of atmospheric storage tanks within the reported sub-basins and counties. Thus, the EPA is proposing to revise these two reporting requirements to request the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas, rather than the minimum and maximum values. These values would be calculated as the sum of all products of the concentration of CO_2 or CH_4 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks. The concentration of CO_2 or CH_4 in the flash gas and the throughput for each storage tank would be determined using the methodologies in Calculation Method 1 or Calculation Method 2. Consistent with section II.C of this preamble, the EPA expects that these revisions would improve both the representative nature of the data collected and the process of verifying annual reported atmospheric storage tanks emissions data under the GHGRP.

7. Calculation Method 3 for Atmospheric Storage Tanks

For hydrocarbon liquids flowing to storage tanks from gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, reporters currently use population emission factors and equation W–15 to calculate volumetric CO_2 and CH_4 emissions per 40 CFR 98.233(j)(3) and report emissions per 40 CFR 98.236(j)(2). Under these current requirements, the count of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day could include separators, wells, or non-separator

[84] Louisiana Department Of Environmental Quality. ''Flash Gas Calculation Methods.'' *https://www.deq.louisiana.gov/page/flash-gas-calculation-methods.*

[85] Texas Commission on Environmental Quality Air Permits Division. May 2012. *Calculating Volatile Organic Compounds (VOC) Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites.* Air Permit Reference Guide APDG 5942. Available at *https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[86] In the 2022 Proposed Rule, the EPA proposed updates to the tank count reporting requirements in current 40 CFR 98.236(j)(1). These revisions are not included in this proposal, as the current tank count reporting requirements better align with the proposed flare stack revisions discussed in section III.N of this preamble.

[87] 87 As discussed in section III.K.3 of this preamble, the EPA is expanding this source to include both fixed roof and floating roof atmospheric storage tanks. The total count of tanks within the facility is proposed to be further divided into the count of fixed roof atmospheric storage tanks and the count of floating roof atmospheric storage tanks. Also, as discussed in section III.K.1 of this preamble, the EPA is also proposing to collect the count of controlled atmospheric storage tanks with open or not properly seated thief hatches.

equipment with annual average daily hydrocarbon liquids throughput of 0 barrels (i.e., separators, wells, or non-separator equipment that were not operated during the reporting year). As a result, some annual reports include a nonzero count of wells with and without separators per existing 40 CFR 98.236(j)(2)(i)(E) and (F) (which, as described in section III.K.7 of this preamble, would be combined in proposed 40 CFR 98.236(j)(2)(ii)(E) and are proposed to be revised to the total number of separators, wells, or non-separator equipment to better match ''Count'' from equation W–15) without any corresponding CO_2 and CH_4 emissions. In these cases, it is not clear if the reporter did not report emissions because emissions are not expected, the emissions data were inadvertently omitted, or the nonzero count of all wells and separators includes those that had no throughput.

Therefore, the EPA is proposing to clarify in 40 CFR 98.233(j)(3) that the separators, wells, or non-separator equipment for which emissions are calculated should be those with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day (i.e., the count should not include separators, wells, or non-separator equipment that had no throughput during the year). Similarly, we are proposing to clarify that the count of separators, wells, or non-separator equipment to report under proposed 40 CFR 98.236(j)(2)(ii)(E) should also be those with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day. These amendments are expected to improve the quality of the data collected, consistent with section II.C of this preamble.

8. Calculation Method 3 Reporting

The provisions in existing 40 CFR 98.236(j)(2)(ii) and (iii) currently require facilities to separately report Calculation Method 3 emissions from atmospheric storage tanks that did not control emissions with flares and those that controlled emissions with flares, respectively. As discussed in section III.N of this preamble, the EPA is proposing new reporting requirements for atmospheric storage tanks controlled by flares. The proposed revisions would require all flared emissions from atmospheric storage tanks with emissions calculated using Calculation Method 3 to be reported under 40 CFR 98.236(n). Therefore, the EPA is proposing to require reporting of all Calculation Method 3 emissions that are vented directly to atmosphere under 40 CFR 98.233(j)(2)(ii).[88] We are proposing to no longer require separate reporting of Calculation Method 3 emissions from atmospheric storage tanks that did not control emissions with flares and those that controlled emissions with flares. This proposed reporting structure would be similar to the emissions reporting structure for Calculation Methods 1 and 2 atmospheric storage tanks. Further discussion on the reasoning behind these proposed revisions is provided in section III.N of this preamble. In the 2022 Proposed Rule, we proposed to revise the reporting structure to specify that the reporting requirements in the current 40 CFR 98.236(j)(2)(iii) only apply to tanks whose emissions were calculated using Calculation Method 3 that used flares to control emissions from at least half the annual hydrocarbon liquids received. As this proposed amendment would not be consistent with the revisions to the flare stack reporting requirements discussed in section III.N of this preamble, the EPA is not including these revisions in this proposal.

For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, reporters currently follow the Calculation Method 3 methodology specified in 40 CFR 98.233(j)(3) and equation W–15 (proposed equation W–15A). Equation W–15 uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in 40 CFR 98.236(j)(2)(i)(E) through (F) require reporters to delineate the count used in equation W–15 into the number of wells with gas-liquid separators in the basin and those without gas-liquid separators. After reviewing these reporting requirements, the EPA has made a preliminary determination that they are not consistent with the language used in the definition of the ''Count'' variable in equation W–15, nor are they inclusive of all equipment to be included in the count. Therefore, the EPA is proposing to revise existing 40 CFR 98.236(j)(2)(i)(E) and (F), in combined proposed 40 CFR 98.236(j)(2)(ii)(E), to completely align the reporting requirement with the total ''Count'' input variable in equation W–15. We are also proposing to collect this information at the well-pad, gathering and boosting site, or facility level. The EPA proposes to amend the language in proposed 40 CFR 98.236(j)(2)(ii)(E) to request the total number of separators, wells, or non-separator equipment used to calculate Calculation Method 3 storage tank emissions. The current language in existing 40 CFR 98.236(j)(2)(i)(E) requests the number of wells with gas-liquid separators in the basin, which is only a subset of the equipment included in the ''Count'' variable. Further, the EPA is proposing to remove the reporting requirement in existing 40 CFR 98.236(j)(2)(i)(F) that requires reporting of the number of wells without gas-liquid separators in the basin. These changes would ensure the consistency of the requirements for all facilities reporting atmospheric storage tanks emissions using Calculation Method 3 and provide activity data that better correlates with the calculated Calculation Method 3 atmospheric tank emissions. Consistent with section II.C of this preamble, reporters would no longer be required to determine two separate counts that may not align with the inputs used in equation W–15.

L. Flared Transmission Storage Tank Vent Emissions

Reporters in the transmission compression industry segment currently are required to report flared emissions specific to their transmission storage tanks under 40 CFR 98.236(k), separately from other flare stack emissions. In the years RY2015 through RY2020, between one and six facilities per year reported having a transmission tank vent stack routed to a flare, and each of these facilities reported no dump valve leakage from the tanks that were routed to flares. As a result, the reported flared emissions from transmission storage tank vent stacks in each of the last 6 years have been 0 mt of CO_2, CH_4, and N_2O. Based on these results, the EPA has made a preliminary determination that including flared emissions from transmission storage tank vents in the group of ''other flared sources'' instead of continuing to report source-specific flared emissions from transmission tanks would not affect data quality or accuracy, nor would it significantly impact the EPA's knowledge of the industry sector, emissions or trends. Therefore, consistent with section II.C of this preamble, the EPA is proposing that transmission storage tanks (proposed to be renamed ''condensate storage tanks'' as described in section III.C.1 of this preamble) be classified as an ''other'' flared source such that any flared emissions from the tanks in the future would be reported only as part of the

[88] As described in section III.C.3 of this preamble, the EPA is proposing new reporting requirements in 40 CFR 98.233(j)(2)(iii) for produced water tanks.

total emissions from the flare. The proposed disaggregation of total flare emissions to individual source types as described in section III.N of this preamble would not apply to condensate storage tanks.

To implement this change for condensate storage tanks that are connected to a flare, the EPA is proposing to remove the current requirements in 40 CFR 98.233(k)(5) that require reporters to monitor the tank vent stack annually for leaks and to quantify the leak rate if a leak is detected. Reporting requirements would remain essentially the same except that flared mass emissions would no longer be reported under 40 CFR 98.236(k)(3). Note that if we decide not to finalize the proposed changes described in this section after considering public comment, then we alternatively propose that we would finalize provisions applying the proposed flare emissions disaggregation requirements as described in section III.N of this preamble to flared emissions from condensate storage tank vent stacks, consistent with the proposed disaggregation of emissions for other source types. Under this alternative, condensate storage tanks would be added to the list of source types in proposed 40 CFR 98.233(n)(10) for which disaggregation would be required. We would also not finalize the proposal to remove the current requirements in 40 CFR 98.233(k)(5) to monitor and quantify leak rates because it would not be possible to tell how much of the total flare emissions should be disaggregated to condensate storage tanks if the scrubber dump valve leakage is not monitored. We request comment on the advantages and disadvantages of both approaches we are considering relative to the current requirements.

M. Associated Gas Venting and Flaring

1. Associated Gas Venting

Associated gas venting or flaring is the venting or flaring of natural gas that originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. Venting associated gas involves directly releasing associated gas into the atmosphere at the well-pad or tank battery. Flaring associated gas is a common, and usually preferred, alternative to venting for safety and environmental reasons. Subpart W currently requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18, which uses the GOR, volume of oil produced, and volume of associated gas sent to sales to calculate the volume of gas vented. Associated gas venting emissions are then calculated using the results of equation W–18 and the gas composition determined using 40 CFR 98.233(u), and associated gas flaring emissions are calculated by applying the calculation method of flare stacks in 40 CFR 98.233(n) to the associated natural gas volume and gas composition determined for the associated gas stream routed to the flare.

For associated gas venting emissions, we are proposing provisions in 40 CFR 98.233(m)(3) to specify that if the reporter measures the flow to a vent using a continuous flow measurement device the reporter must use the measured flow volumes to calculate the volume of gas vented rather than using equation W–18. This proposed amendment would add calculation methodologies based on measurements and improve the accuracy of the data collected, consistent with section II.B of this preamble. We are proposing corresponding reporting requirements for associated gas venting emissions in 40 CFR 98.236(m)(7), including requiring an indication of whether a continuous flow monitor or continuous composition analyzer was used. We are also proposing to require reporting of the flow-weighted mole fractions of CH_4 and CO_2 and the total volume of associated gas vented from the well, in standard cubic feet for all wells whether using GOR or continuous flow measurement devices. Finally, we are proposing to specify that if the volumetric emissions from associated gas venting and flaring were determined using a continuous flow measurement device rather than equation W–18, then reporting of the inputs to equation W–18, including the GOR, the volume of oil produced, and the volume of gas sent to sales for wells with associated gas venting or flaring, would not be required for that well. We request comment on whether we should continue to require reporting of these data elements even if they are not used as inputs to an emissions calculation. 40 CFR 98.236(m)(7)(i) currently requires the reporter to provide the total number of wells and a list of well IDs in the sub-basin for wells that vented associated gas emissions. As noted in section III.D of this preamble, however, the EPA is proposing that reporters begin reporting information for this emission source by well rather than at the sub-basin level. Therefore, we are proposing to remove this reporting requirement. The well ID would be reported for each vented well under proposed 40 CFR 98.236(m)(1) and the total number of wells reported at the sub-basin level is no longer necessary, because we are proposing to require reporting at the well level for associated gas venting rather than the sub-basin level.

As discussed further in section III.N of this preamble, the EPA is proposing several amendments to the calculation and reporting requirements for flare stacks that would impact associated gas flaring emissions calculations in existing 40 CFR 98.233(m)(5) and reporting in existing 40 CFR 98.236(m)(8). As a result, the EPA is proposing to remove existing 40 CFR 98.233(m)(5) and instead direct reporters to 40 CFR 98.233(n) to calculate emissions from associated gas flaring. The EPA is also proposing to remove 40 CFR 98.236(m)(8), as flared emissions would be reported under 40 CFR 98.236(n). In addition to flared emissions, 40 CFR 98.236(m)(8)(i) currently requires the reporter to provide a list of well IDs in the sub-basin for wells that flared associated gas emissions. As noted in section III.D of this preamble, however, the EPA is proposing that reporters begin reporting information for this emission source by well rather than at the sub-basin level. Existing 40 CFR 98.236(m)(3) requires reporters to indicate whether any associated gas was flared. The EPA is not proposing to revise this requirement. Thus, reporters would still be required to indicate whether associated gas was flared but would report this information at the well level rather than the sub-basin level under the proposed rule. Retaining the requirement to provide a list of well IDs as required by current 40 CFR 98.236(m)(8)(i) would effectively duplicate the proposed requirement to indicate if associated gas is flared in 40 CFR 98.236(m)(3) for each well. Therefore, the EPA is proposing to remove existing 40 CFR 98.236(m)(8)(i) in addition to all other requirements in 40 CFR 98.236(m)(8).

2. Oil and Gas Volumes

As noted previously in this section, subpart W currently requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18. Two of the inputs in the equation are the volume of oil produced and volume of associated gas sent to sales for each well in the sub-basin during time periods in which associated gas was vented or flared. However, based on the values initially reported in some annual GHGRP reports and correspondence with reporters via e-GGRT, it appears that reporters, in a limited number of cases, may have incorrectly interpreted the language of equation W–18 to require reporting of gas sent to sales summed across all sub-basins at the facility during time periods in which associated gas was vented or flared under existing 40 CFR 98.236(m)(6) rather than gas sent to sales in the sub-basin during these flaring and venting periods. Thus, the total sales volume reported for the associated gas source in these instances is the same as the total volume of gas sent to sales for the facility reported under existing 40 CFR 98.236(aa)(1)(i)(B). If these reporters are accurately reporting the volume of gas sent to sales during flaring and venting associated gas events and using that volume in equation W–18, then the associated gas venting and flaring emissions are likely overstated, as it is unlikely that all wells are venting or flaring associated gas 100 percent of the time. If the reporters are using accurate volumes of gas sent to sales during time periods in which associated gas was vented or flared for their emissions calculations but reporting total gas sent to sales, then the activity data reported do not match the emissions, leading to an inconsistent data set. Therefore, the EPA is proposing to add the word ''only'' to the definitions of the terms $V_{p,q}$ and $SG_{p,q}$ in equation W–18 (40 CFR 98.233(m)(3)) and to the reporting requirements for those data elements in 40 CFR 98.236(m)(5) and (6).These proposed amendments would lead to improved accuracy of reported emissions, consistent with sections II.C and II.D of this preamble.

The EPA is further proposing to clarify the definition of the variable SGp,q in equation W–18 to account for associated gas used at the facility. Currently, the term is defined as ''Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year during time periods in which associated gas was vented or flared.'' That volume is subtracted from the total volume of associated gas produced to provide a net volume of gas sent to a vent or flare at each well. However, an operator may use the produced gas at the well-pad, further reducing the volume of gas sent to sales. For example, produced gas is often used as fuel for internal combustion engines or for separators. For this reason, the EPA is proposing to amend the definition of $SG_{p,q}$ in equation W–18 to include these additional uses. Specifically, we propose to revise the variable name to SG_p (*i.e.,* we propose to remove the ''q'' subscript) to indicate that the emissions would no longer be summed and reported by sub-basin (as described in more detail in section III.D of this proposal). We propose to define SG_p as the volume of associated gas sent to sales or volume of associated gas used for other purposes at the facility site, including powering engines, separators, safety systems and/or combustion equipment and not flared or vented, for well p, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared. Incorporating these proposed changes would add clarity to equation W–18, consistent with section II.D of this preamble, resulting in more accurate reporting of actual volumes of associated gas sent to a vent or flare and thus more accurate emissions reporting, consistent with section II.C of this preamble. Consistent with these changes, the EPA is also proposing to amend reporting requirements in 40 CFR 98.236(m)(6) to clarify that $SG_{p,q}$ includes associated gas that is used on-site at the facility but not sent to a flare or vent.

N. Flare Stack Emissions

Flare stacks are an emission source type subject to emissions reporting by facilities in seven of the ten industry segments in the Petroleum and Natural Gas Systems source category.[89] Total CO_2, CH_4, and N_2O emissions from each flare currently are required to be calculated using the methodology specified in 40 CFR 98.233(n). In addition to calculating total emissions from a flare, reporters currently must also separately calculate the flared emissions from several types of emission sources as specified in the requirements of 40 CFR 98.233 specific to that source type.[90] The procedures in the source-specific paragraphs of the existing rule cross-reference the calculation procedures in existing 40 CFR 98.233(n), but they also specify that the volume and composition of the gas routed to the flare are required to be determined according to the procedures for estimating vented emissions from the specific source type. For example, existing 40 CFR 98.233(e)(6) specifies that the volume and gas composition to use in calculating flared emissions from dehydrators must be determined according to the procedures for calculating vented emissions from dehydrators as specified in existing 40 CFR 98.233(e)(1) through (5). Since source-specific flared emissions often are a portion of the total emissions from a flare, existing 40 CFR 98.233(n)(9) specifies that the total CO_2, CH_4, and N_2O for a particular flare must be adjusted downward by the amount of the source-specific emissions that are calculated for the same flare; this ensures that emissions from a flare are not double counted (i.e., reported for both the flare stacks source type and another emission source type). The resulting CO_2, CH_4, and N_2O emissions to report for that flare according to existing 40 CFR 98.236(n)(9) through (11) should be only what is left after subtracting all of the source-specific flared emissions from the total emissions.

When a flare is dedicated to one or more source types that are all subject to source-specific flared emissions reporting, all of the mass emissions are currently reported under those source types, and zero mass emissions are reported for the flare stacks source types. However, even when the only streams routed to a flare are from source types that are subject to flared emissions reporting under those source types, the flare name or ID and all activity data related to the streams that are routed to the flare and the flare operating characteristics still must be reported under existing 40 CFR 98.236(n). These activity data include the volume of gas routed to the flare, average CO_2 and CH_4 mole fractions in the flared gas, flare combustion efficiency, fraction of flared gas routed to the flare when it was unlit, and indicators of whether a continuous flow measurement device and a continuous gas analyzer were used on the gas stream routed to the flare. These flare ID and activity data reporting requirements are specified in existing 40 CFR 98.236(n)(1) through (8). In the rare cases that a CEMS is used on the outlet of a flare, then according to existing 40 CFR 98.236(n)(12), only the flare ID and the measured CO_2 emissions must be reported.

The EPA is proposing changes to the flared emissions calculation

[89] Flare stacks are an emission source type currently subject to emissions reporting by facilities in the following industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Import and Export Equipment, and LNG Storage.

[90] Facilities currently separately calculate the flared emissions from the following types of emission sources (if required for the applicable industry segment, per 40 CFR 98.232): dehydrator vents (40 CFR 98.233(e)(6)), well venting during completions and workovers with hydraulic fracturing (40 CFR 98.233(g)(4)), gas well venting during completions and workovers without hydraulic fracturing (40 CFR 98.233(h)(2)), onshore production and onshore petroleum and natural gas gathering and boosting storage tanks (40 CFR 98.233(j)(5)), transmission storage tanks (40 CFR 98.233(k)(5)), well testing venting and flaring (40 CFR 98.233(l)(6)), and associated gas venting and flaring (40 CFR 98.233(m)(5)).

methodologies, including the monitoring provisions, as well as the flare data reporting requirements for both the flared emissions from each source type and for each flare. The proposed changes would align the flared emissions calculation methodology and reporting with the requirements in CAA section 136(h) to report emissions that are based on empirical data and that accurately reflect the total CH_4 emissions from each facility, consistent with section II.B of this proposal. We are also proposing changes to clarify specific provisions.

1. Calculation Methodology for Total Emissions from a Flare

The EPA is proposing several revisions to the flare emission calculation methods to improve the quality and accuracy of the calculated and reported data, consistent with section II.B of this proposal. First, we are proposing to revise the default combustion efficiency for flares. Currently, reporters may assume a default combustion efficiency of 98 percent, as provided in existing 40 CFR 98.233(n)(3). However, researchers conducting remote sensing tests of emissions from flares have reported finding lower combustion efficiencies. For example, Plant *et al*. conducted extensive testing in the Eagle Ford, Bakken, and Permian basins and found average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin.[91] Consistent with the requirements of CAA section 136(h), we are proposing a tiered approach to setting the default combustion efficiency that would provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in proposed 40 CFR 98.233(n)(4). Specifically, under Tier 1, a default combustion efficiency of 98 percent would be allowed where the reporter conducts flare monitoring consistent with the procedures specified in 40 CFR 63.670 and 40 CFR 63.671 of the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (40 CFR part 63, subpart CC) (hereafter referred to as ''NESHAP CC''). The standard in NESHAP CC is to either reduce emissions by 98 percent or comply with the specified flare requirements, as verified via monitoring. Therefore, under NESHAP CC, it is presumed that complying with the flare requirements achieve at least a 98 percent reduction in emissions. Under Tier 2, a default combustion efficiency of 95 percent would be allowed if the reporter is required to or elects to comply with the monitoring specified in proposed 40 CFR 60.5417b(d)(1)(viii) of NSPS OOOOb. The standard in NSPS OOOOb is 95 percent, and it is presumed that this standard is met when the specified monitoring is conducted and the corresponding activity data limits are met. The default combustion efficiency under Tier 3, which would apply if neither Tier 1 nor Tier 2 requirements are met, would be 92 percent. This value is based on the low end of the range of empirical results observed in testing over an extensive area in three of the most active basins in the United States (U.S.) in Plant *et al*. Our assessment is that this would be a reasonable combustion efficiency for subpart W sources that are not monitoring as specified under Tier 1 or Tier 2 because the overall average in the empirical results likely included many facilities that would comply with those tiers and thus should be excluded from the calculation of the average for Tier 3 flares. We are proposing Tier 3 to provide a default combustion efficiency that would apply before the flare owner or operator has implemented the monitoring that would be required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 and that would be consistent with CAA section 136(h).

We request comment on our proposed approach and values, including whether available data would support the selection of other default values for any of the tiers. In addition, we request comment on whether Tier 3 should be included in the final provisions and if so, whether the data support using a default combustion efficiency of 92 percent or another value. If commenters do not agree that Tier 3 is appropriate, we request that the commenters include what alternative approach should be specified for reporters to use for calculating the combustion efficiency that would be consistent with the requirements in CAA section 136(h) to accurately reflect total CH4 emissions and to base reporting on empirical data. Under an approach where only Tier 1 and Tier 2 were included, we expect that some period of time would be needed for flares not subject to NSPS OOOOb to implement the requirements, potentially the same period of time until the facility is subject to an approved state plan or applicable Federal plan in 40 CFR part 62. We request comment on this possible time frame and what procedures and combustion efficiency should be implemented in the interim.

Second, for all flares, regardless of the tier discussed above, we are proposing to require at least continuous parameter monitoring to determine gas flow to the flare. Currently, under 40 CFR 98.233(n)(1), if a continuous flow measurement device is used on part or all of the gas routed to the flare, then the measured values must be used in the calculation of emissions from the flare. For the portion of gas not measured by a continuous flow measurement device, the reporter currently may estimate the flow using engineering calculations based on process knowledge, company records, and best available data. We are proposing a more defined empirical method for determining the gas flow to the flare, consistent with section II.B of this proposal. Specifically, the proposed revisions to 40 CFR 98.233(n)(1) specify that the flow rate determination must be based on direct measurement using a flow meter if one is present, or if a flow meter is not available, it must be based on indirect calculation of flow using continuous parameter monitoring, such as line pressure, burner nozzle dimensions, and appropriate engineering calculations. We are also proposing that the monitoring could be conducted on either the inlet gas to the flare or on each of the individual streams that are combined for routing to the flare.

Third, for all flares, regardless of the tier discussed previously in this section, we are proposing in 40 CFR 98.233(n)(2) to require either continuous monitoring (proposed 40 CFR 98.233(n)(2)(i)) or visual inspection at least once per month (proposed 40 CFR 98.233(n)(2)(ii)) for the presence of pilot flame or combustion flame. During periods when a continuous monitoring device is out of service, we are proposing that visual inspections be conducted at least once per week for the first four weeks of the outage or until a new or repaired continuous monitoring device is operational. If the outage is less than one week, then we are proposing that at least one visual inspection must be conducted during the time the continuous monitoring device is out of service. If an outage lasts more than four weeks, then we are proposing that the reporter may switch to conducting visual inspections at least once per month in accordance with proposed 40 CFR 98.233(n)(2)(ii). Data from these measurements or inspections, combined with continuous flow data as described previously in this section, would be used to determine the

[91] Plant, G., *et al*. 2022. ''Inefficient and unlit natural gas flares both emit large quantities of methane.'' Science, 377 (6614). *https://doi.org/10.1126/science.abq0385*. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

amount of gas routed to the flare when it was unlit. Currently, subpart W specifies that the fraction of gas sent to an unlit flare is to be determined by engineering estimate and process knowledge based on best available data and operating records (as provided in the definition of the variable Z_U for existing equations W–19 and W–20 of 40 CFR 98.233). Researchers conducting remote sensing testing of flares have identified higher percentages of unlit flares than the average fractions of gas routed to unlit flares reported under subpart W.[92] Although the percentage of flares that are unlit may not equal the fraction of gas routed to unlit flares, the difference suggests there is a potential for the reported fractions of gas routed to unlit flares to be underestimated. Therefore, we are proposing a more defined empirical method of determining the fraction of gas sent to the flare when it is unlit, consistent with section II.B of this proposal. The proposed requirement for continuous monitoring or periodic visual inspection of the pilot flame or combustion flame would provide flare-specific information on the specific times when the flare was unlit. The proposed continuous determination of the flow of gas to the flare, as described earlier in this section, would provide an accurate determination of the flow during the periods when the flare is unlit. Together, the information from both measurements would be used to calculate the total amount of gas routed to the flare when it is unlit. Dividing this amount by the total annual flow would give the fraction sent to the flare when it was unlit, which would be used in equations W–19 and W–20 to calculate the total annual CH_4 and CO_2 emissions, respectively, from the flare. If a flame is not present during a visual inspection, then the reporter must assume it was unlit since the previous inspection that confirmed the presence of a flame and that it remains unlit until the next inspection that confirms the presence of a flame. These assumptions are consistent with the existing requirements for estimating the time over which a leak occurs based on equipment leak inspections.

Fourth, we are proposing changes to the determination of gas composition to make the results more accurate, consistent with section II.B of this proposal. Currently, under 40 CFR 98.233(n)(2), if a reporter is using a continuous gas composition analyzer on gas to the flare, then the measured data must be used in the calculation of emissions from the flare. However, if the reporter does not use a continuous gas composition analyzer, we have reassessed the current subpart W requirements that apply and think that they should be revised to improve clarity and thus better correspondingly result in calculated emissions that accurately reflect CH_4 emissions at the facility. Specifically, existing 40 CFR 98.233(n)(2) requires determination of ''the appropriate gas compositions for each stream of hydrocarbons going to the flare . . .'' However, 40 CFR 98.233(u)(2)(i) for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities requires the reporter to use an annual average gas composition based on the most recent available analysis of the facility. Although not explicitly stated, one interpretation is that the ''most recent available analysis'' should be for each stream of hydrocarbons routed to the flare. Another interpretation of 40 CFR 98.233(u)(2)(i) is that the composition of produced gas may be used for all streams routed to the flare. This interpretation is based on the first sentence in existing 40 CFR 98.233(u)(2)(i) that states: ''If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction.'' Given the ambiguity in the existing regulations, to date the EPA has not sent validation messages to have all facilities report using only one of the possible interpretations. Another concern with the current procedures for determining gas composition when not using a continuous gas composition analyzer is that there is no requirement to conduct additional sampling and analysis over time, and subpart W does not specify how compositions from multiple streams are to be weighted to generate the constituent mole fractions of the total combined stream into the flare that are to be used in equations W–19 and W–20. The current requirements for determining gas compositions for flared streams in other industry segments are clearer. However, one of the options for transmission compression, underground natural gas storage, LNG storage, LNG import/export facilities, and transmission pipeline industry segments is to use a default CH_4 composition of 95 percent, which may not accurately represent the composition of the gas flow routed to flares for some facilities. The proposed revisions to the flare stacks methodology would delete the cross-reference to 40 CFR 98.233(u)(2) and specify the gas composition determination requirements within proposed 40 CFR 98.233(n)(3). The proposed options are to use a continuous gas composition analyzer or to take samples for compositional analysis at least once each quarter in which the flare operated. If a continuous gas analyzer is used, then the measured data would be required to be used to calculate flared emissions. Reporters would be allowed to determine the composition of either the inlet gas to the flare or on each of the streams that are routed to the flare. If periodic samples are collected, then the measured concentrations would be combined with flow data over the same time periods to calculate flow-weighted annual average concentrations.

Fifth, for clarity, we are proposing to add requirements in existing 40 CFR 98.233(n)(5) to specify how flow and composition data would be used to calculate total emissions depending on different scenarios a reporter could use to determine the flow and gas composition. Proposed 40 CFR 98.233(n)(5)(i) specifies that if both flow and gas composition are determined for the inlet gas to the flare, then the inlet gas data would be used in a single application of equations W–19 and W–20 to calculate the total emissions from the flare. If the flow and gas composition are determined for each of the streams that are routed to the flare, then one proposed option in proposed 40 CFR 98.233(n)(5)(iii) would require the reporter to use each set of stream-specific flow and annual average concentration data in equations W–19 and W–20 to calculate stream-specific flared emissions for each stream, and then sum the results from each stream-specific calculation to calculate the total emissions from the flare. Alternatively, in such circumstances proposed 40 CFR 98.233(n)(5)(iii) would also allow reporters to sum the flows from each source to calculate the total gas flow into the flare and use the source-specific flows and source-specific annual average concentrations to determine flow-weighted annual average concentrations of CO_2 and hydrocarbon constituents in the combined gas stream into the flare. The calculated total gas flow and the calculated flow-weighted annual average concentrations would then be used in a single application of both equation W–19 and W–20 to calculate the total emissions from the flare. If flow is determined for all of the individual source streams while gas composition is determined for the

[92] See, *e.g.,* Plant, G., *et al.* 2022. ''Inefficient and unlit natural gas flares both emit large quantities of methane.'' Science, 377 (6614). *https://doi.org/10.1126/science.abq0385.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

combined stream into the flare, then proposed 40 CFR 98.233(n)(5)(ii) would require the reporter to sum the individual source flows to calculate the total flow into the flare. This summed volume and the gas composition determined for the stream into the flare would be used in a single application of equations W–19 and W–20 to calculate the total emissions from the flare. Finally, in 40 CFR 98.233(n)(5)(iv) we are proposing that a reporter may not calculate flared emissions based on the determination of the total volume at the inlet to the flare and gas composition for each of the individual streams routed to the flare. The proposal would not allow this combination of volume and gas composition determinations because there is no way to calculate flow-weighted average compositions of either the inlet gas to the flare or the individual source streams.

Sixth, we are proposing to delete the option to use a default higher heating value (HHV) in the calculation of N_2O emissions and instead require all reporters to use either a flare-specific HHV or individual flared gas stream-specific HHVs in the calculation. Currently, 40 CFR 98.233(n)(7) requires the use of equation W–40 to calculate N_2O emissions from flares. This equation requires the flared gas volume, the HHV of the flared gas, and the use of a default emission factor. For field gas or process vent gas, the variable definition for the HHV provides that either a site-specific or default value may be used; for other gas streams, a site-specific HHV must be used. We are proposing in 40 CFR 98.233(n)(8) to require the use of a flare-specific HHV when composition of the inlet gas to the flare is measured or when flow-weighted concentrations of the inlet gas are calculated from measured flow and composition of each of the streams routed to the flare. Similarly, we are proposing that reporters would calculate N_2O emissions using flared gas stream-specific HHVs when flow and composition are determined for each of the individual streams that are routed to the flare and emissions are calculated per stream and summed to calculate total emissions from the flare. We are proposing this change because we believe flare-specific values more accurately represent the HHV of variable flared gas composition and would result in more accurate calculation of N_2O emissions. Our assessment is that the methods for calculating CO_2 and CH_4 in 40 CFR 98.233(n) already require the use of flare-specific concentrations for the hydrocarbon constituents in the flared gas streams; therefore, we expect that a flare-specific HHV is known (or can be calculated using the compositional data) without incurring additional burden, while increasing the accuracy of the emissions estimate. We are also proposing to add a requirement in 40 CFR 98.236(n)(9) to report the HHV(s) used to calculate N_2O emissions. This data element would improve verification of reported N_2O emissions and minimize the amount of communication with reporters via e-GGRT. It also would be useful for characterizing the differences in flared gas streams among the various industry segments and basins, and it is expected to be useful in analyses such as updates to the U.S. GHG Inventory.

Seventh, we are proposing changes to the emission calculation requirements for flares that use CEMS in order to address requirements in CAA section 136(h) as described in section II.B of this preamble. Currently, if a reporter operates and maintains a CEMS to monitor emissions from a flare, existing 40 CFR 98.233(n)(8) requires the reporter to calculate only CO_2 emissions from the flare. This proposal would revise existing 40 CFR 98.233(n)(8) (proposed 40 CFR 98.233(n)(9)) to require reporters to comply with all of the other emission calculation procedures in proposed 40 CFR 98.233(n), with one exception. The exception is that since CO_2 emissions would be measured with the CEMS, calculation of CO_2 emissions using equation W–20 would not be required. We expect that these proposed amendments would address a potential gap in CH_4 emissions reporting and improve the overall quality and completeness of the emissions data collected by the GHGRP, consistent with section II.A of this preamble.

Eighth, we are proposing to replace the current source-specific methodologies for calculating flared emissions (*e.g.,* existing 40 CFR 98.233(e)(6) for dehydrators or existing 40 CFR 98.233(g)(4) for completions) with a requirement (proposed 40 CFR 98.233(n)(10)) that the reporter use engineering calculations and best available data to disaggregate the calculated total emissions per flare to the source types that routed gas to the flare. One issue with the current source-specific flared emission calculation methodologies is that the equation inputs developed under these methodologies (*e.g.,* flared volumes and compositions) often differ from the inputs used in the methodology to calculate the total emissions from the flare (as specified in existing 40 CFR 98.233(n)). As a result, when using the existing methodologies, the sum of the flared emissions calculated for individual source types sometimes exceeds the total emissions calculated using the methodology for calculating total emissions from the flare. The proposed change would eliminate this issue because only the flare methodology would be used to calculate emissions from a flare, and only these values would be included in the published data set for the reporting year. Since estimates of the flared emissions from source types that route emissions to flares are still useful in other analyses (*e.g.,* assessing impacts of emission control regulations on nationwide emission trends), the proposed methodology also would require reporters to estimate the portions of the total emissions from each flare that are attributable to each type of source that is currently subject to flared emissions reporting (*e.g.,* completions, storage tanks, associated gas). The expected accuracy of the estimated quantities per source type may sometimes be lower than the expected accuracy of the total emissions from the flare since the source-specific estimates would be based on best available data, which may be of more variable quality. However, the expectation is that the sum of the estimated emissions over all source types will always equal the calculated (and reported) total emissions from the flare, and it is expected that the results will be of sufficient accuracy for their intended purpose.

This proposed change would also address a common misperception among reporters regarding the flare activity data that is to be reported under existing 40 CFR 98.236(n). Many reporters have provided information through the GHGRP Help Desk and in correspondence with the EPA via e-GGRT indicating that they believe the adjustment requirement in existing 40 CFR 98.233(n)(9) applies to all flare data, not just the mass emissions (as intended). Thus, some reporters provide activity data information for a flare only if some of the mass emissions from the flare are due to combustion of gas from source types that are not subject to source-specific flared emissions reporting (*i.e.,* miscellaneous flared sources). Although these reporters generally correctly report the mass emissions from the flare that are due to the miscellaneous flared sources, they incorrectly limit their activity data reporting to those same streams. The EPA has procedures in its verification process to identify such errors; if errors are identified, the EPA notifies the reporter, who can resolve the issue by correcting the data and resubmitting their annual GHG report. Some reporters have also indicated that they dislike reporting activity data for a flare in one table in the reporting form (*i.e.,* Table N.1) and reporting the emissions in a different table; they suggest that it would be clearer to report all flare activity data and emissions related to a particular emission source type together in one location.

We also expect that the total emissions per flare calculated using the proposed methodology described above would be more accurate than the emissions calculated using the current source-specific methodologies. While similar changes to the methods for determining flow rate and composition of the gas routed to the flare could be proposed for each of the source-specific methodologies, we have tentatively determined that the additional accuracy in the source-specific flared emissions relative to calculation of disaggregated total emissions based on best available data is not needed given the additional burden that would be imposed, as the total flared emissions are expected to be accurate; in other words, applying source-level methods for flares over the proposed method would not be expected to have an impact on the accuracy of the total emissions calculated. However, the proposed approach would still maintain calculation and reporting of flared emissions per source type because of that information's importance for use in assessing trends in control over time and in policy determinations under the CAA, and it would also be useful in U.S. GHG Inventory development.

Finally, we are proposing to remove existing 40 CFR 98.233(n)(9) for consistency with the other proposed provisions in this subsection, as the requirement to correct flare emissions to avoid double counting would no longer be necessary because the disaggregated emissions would not be a separate source type.

2. Reporting Requirements for Flared Emissions

The EPA is proposing several changes to the reporting requirements for flares. These changes are being proposed to align reporting in 40 CFR 98.236(n) with the proposed revisions to the calculation methods specified in proposed 40 CFR 98.233(n), consistent with section II.B of this preamble, and to improve the verification process, obtain a better understanding of the design and operation of flares in each of the industry segment to help future policy determinations, and clarify ambiguous provisions.

First, the EPA is proposing to replace the source-specific flared CH_4, CO_2, and N_2O emissions reporting requirements currently in 40 CFR 98.236(e), (g), (h), (j), (l), (m), and (n) with a requirement to report source-specific CH_4, CO_2, and N_2O emissions that have been disaggregated from the total flare emissions as described in section III.N.1 of this preamble. The disaggregated emissions per source type would be reported per flare under proposed 40 CFR 98.236(n)(19). We are proposing to remove the source-specific flared CH_4, CO_2, and N_2O emissions reporting requirements currently in 40 CFR 98.236(k), but for the reasons discussed in section III.L of this preamble, we are not proposing to include condensate storage tanks in this list of source types for which emissions would be disaggregated in proposed 40 CFR 98.236(n)(19). We are also proposing to include AGR vents in the list of source types for which emissions would be disaggregated in proposed 40 CFR 98.236(n)(19), even though emissions from flaring are not currently reported separately for that source, due to the proposed addition of reporting of CH_4 emissions from that source type, as discussed further in section III.F.1 of this preamble. In addition to aligning the reporting with the proposed calculation methodology, reporting the disaggregated emissions per flare rather than per facility, sub-basin, or county (under the current provisions of subpart W), and rather than per well-pad, gathering and boosting site, or facility (as is being proposed for vented emissions), would provide the EPA and other stakeholders with a better understanding of the impact of different emission source types on the performance of flares. We are proposing to retain some of the unit-specific activity data for source types that are flared as described throughout this preamble in the sections that describe amendments specific to those source types (*e.g.,* section III.F.2 of this preamble for AGR vents, sections III.K.6 and III.K.8 of this preamble for atmospheric storage tanks, section III.M.1 for associated gas flaring).

Second, the EPA is proposing to add a requirement for facilities in the Onshore Petroleum and Natural Gas Production industry segment, the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, and the Onshore Natural Gas Processing industry segment to report an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations. A finding from the currently reported data is that a number of facilities in these industry segments report significant amounts of emissions from miscellaneous flared sources. It is not clear what sources are generating the large amount of gas that is routed to these flares. It is important to know what source types are generating the large amounts of flared gas because the same source type may not always be routing the gas to a flare. If the source type also is not currently subject to source-specific reporting of vented emissions, then a potentially large quantity of vented emissions might go unreported. It appears that one potential source of currently undefined sources of flared emissions is emissions from one facility that are routed to another facility specifically for flaring. To help the EPA understand what source types are generating the large amounts of flared gas, we are proposing in 40 CFR 98.236(n)(10) to require reporting by facilities in these three industry segments of an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations. As an example, if an owner or operator has an onshore petroleum and natural gas production and an onshore petroleum and natural gas gathering and boosting facility in the same basin and routes associated gas from wells in the onshore petroleum and natural gas production facility to a flare that is defined as part of the onshore petroleum and natural gas gathering and boosting facility, then the flared emissions would be reported by the onshore petroleum and natural gas gathering and boosting facility as emissions from ''other flare stacks'' sources under the current rule (or from other flared sources under the proposed amendments). If the other gas streams routed to the flare are from sources at the onshore petroleum and natural gas gathering and boosting facility, then for this proposed reporting requirement, the onshore petroleum and natural gas gathering and boosting facility report would include an estimate of the fraction of the total gas burned in the flare that is associated gas from the onshore petroleum and natural gas production facility. We request comment on the types of sources (both onsite sources and offsite sources) that may be generating these large emissions and whether other reporting elements could be specified that would better achieve the EPA's objective of clearly characterizing the sources of flared emissions from facilities in the three industry segments identified above. For example, we have considered adding a reporting element to identify for each flare the source type in the category of ''other flared sources'' under this proposal that routes the largest quantity of gas to the flare. We also request comment on whether there should be a minimum threshold for the amount of gas routed from a source in the ''other flared sources'' category before reporting the identity of the source type would be required and the basis for any such threshold.

Third, we are proposing adjustments to several of the existing reporting elements to align with proposed changes to the calculation methodology. For example, existing 40 CFR 98.236(n)(4) requires reporting of the total volume of gas routed to the flare. As described in section III.N.1 of this preamble, we are proposing to add an option for reporters to monitor volume of each stream routed to the flare. To align with this monitoring approach, we are proposing in 40 CFR 98.236(n)(11) to require reporting of the volumes for each of the individual streams if the reporter elects to monitor the flow rate of the individual streams rather than the total. Similarly, existing 40 CFR 98.236(n)(7) and (8) require reporting of the CH_4 and CO_2 in the feed gas to the flare. To align with the proposed option that would allow determination of gas composition at all of the source stream levels as an alternative to determination of the composition at the flare inlet, as discussed in section III.N.1 of this preamble, proposed 40 CFR 98.236(n)(14) and (15) also would require reporting of the annual CH_4 and CO_2 mole fractions for each of the individual streams routed to the flare if the reporter elects to monitor composition of those streams. Existing 40 CFR 98.236(n)(6) requires reporting of the flare combustion efficiency. To align with the proposed monitoring tiers, as discussed in section III.N.1 of this preamble, proposed 40 CFR 98.236(n)(13) would require reporting of the default combustion efficiency associated with applicable monitoring tier. In addition, if a reporter switches from one monitoring tier to another and calculates emissions for part of the year using the default combustion efficiency for one tier and calculates emissions for the rest of the year using the default combustion efficiency for a different tier, then proposed 40 CFR 98.236(n)(13) would require reporting of a flow-weighted average combustion efficiency for that flare. We are proposing that flow-weighted average combustion efficiencies be reported to one decimal place. These data also would help with verification of the reported emissions.

Existing 40 CFR 98.236(n)(12) requires reporting of whether a CEMS was used to measure CO_2 emissions from the flare. We are proposing to keep this reporting requirement (in proposed 40 CFR 98.236(n)(20)), but to align with the proposed calculation procedures when using CEMS, as described in section III.N.1 of this preamble, we are also proposing to specify that the CO_2 mole fraction of the gas sent to the flare should not be reported when using CEMS because equation W–20 is not used to calculate CO_2 emissions when using a CEMS.

We are proposing changes to the continuous flow and gas composition measurement indicator data elements to require reporting of specific measurement methodologies that were used instead of the current ''yes/no'' indicators. Currently, existing 40 CFR 98.236(n)(2) requires reporting of whether the flare stack has a continuous flow measurement device and existing 40 CFR 98.236(n)(3) requires reporting of whether the flare stack has a continuous gas analyzer (these are yes/no indicators). The proposed 40 CFR 989.236(n)(7) would require reporters to indicate whether flow is determined using a continuous flow measurement device or whether they use a continuous parameter monitoring system with engineering calculations. Similarly, the proposed 40 CFR 98.236(n)(8) would require reporters to indicate whether gas composition is measured using a continuous gas analyzer or by taking periodic samples.

We are also proposing to add a reporting element in proposed 40 CFR 98.236(n)(13)(i) for facilities that report flares using a combustion efficiency of 95 percent to indicate whether the flare is subject to NSPS OOOOb or a State or Federal plan in part 62 implementing EG OOOOc or whether the reporter is electing to implement flare monitoring procedures that are specified in NSPS OOOOb or a State or Federal Plan in part 62 implementing EG OOOOc. This information would help the EPA verify the reported data.

Finally, one objective of the current flare reporting requirements is to obtain information on the total number of flares and their operating characteristics. We are proposing to require a few new flare-specific reporting elements to help us better understand the state of flaring in the industry and to improve data quality, such as an indication of the type of the flare (*e.g.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare) in 40 CFR 98.236(n)(4) and the type of flare assist (*e.g.,* unassisted, air-assisted (with indication of single-, dual-, or variable-speed fan), steam-assisted, or pressure-assisted) in proposed 40 CFR 98.236(n)(5). These data would help the EPA assess the impact of design and operation on emissions and may be useful in analyses for potential future policy decisions related to flares under the CAA. To harmonize the proposed reporting requirements with the proposed requirement to either continuously monitor or periodically inspect for the presence of a pilot flame as discussed in section III.N.1 of this preamble, we are proposing in proposed 40 CFR 98.236(n)(6) that reporters indicate for each flare whether they continuously monitor for the presence of a pilot flame, conduct periodic visual inspections, or both. If periodic visual inspections are conducted, we are proposing to require reporting of the count of inspections conducted during the year and an indication of whether the flare has a continuous pilot or auto igniter. For a pilot flame that is monitored continuously, we are proposing to require reporting of the number of times the continuous monitoring device was out of service or otherwise inoperable for a period of more than one week.

3. Definition of Flare Stack Emissions

In response to a verification message in e-GGRT, one reporter noted that the existing definition of the term ''flare stack emissions'' in 40 CFR 98.238 does not include CO_2 that is in streams routed to the flare. The term is currently defined to mean ''CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.'' Based on this definition, the reporter concluded that CO_2 in streams routed to the flare are not to be reported as flare stack emissions. The current definition, which was added to the 2010 Final Rule after consideration of comments on the 2010 re-proposal, does not clearly convey the EPA's intent that the CO_2 that enters a flare should be reported as flare stack emissions. This intent is evident from the fact that equation W–20 includes a term for the inlet gas volume times the CO_2 mole fraction in the inlet gas. Additionally, in a response to a comment on the 2010 re-proposal, the EPA clearly stated that the total quantity of CO_2, including both combusted CO_2 (*i.e.,* CO_2 created in the flare) and uncombusted CO_2 (*i.e.,* CO_2 that entered and simply passed through the flare), is to be calculated. Another issue with the current definition is that it implies N_2O emissions only result from partial combustion of hydrocarbons in the gas routed to the flare. This is likely the primary mechanism for generating N_2O emissions when combusting fuels that include nitrogen-containing compounds. However, natural gas and field gas have negligible amounts of fuel-bound nitrogen. For combustion of these fuels, it appears the N_2O is generated primarily from converting thermal nitrogen oxides (NO_X) under certain operating conditions in the flare. Consistent with section II.D of this preamble, in order to eliminate the unintended inconsistency between the definition and the intent that CO_2 in gas routed to the flare is to be reported as emissions from the flare, to clarify the requirement to calculate and report total CO_2 that leaves the flare, and to clarify the source of flared N_2O emissions, we are proposing to revise the definition of the term ''flare stack emissions'' in 40 CFR 98.238 to mean CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

O. Compressors

Compressors are used across the petroleum and natural gas industry to raise the pressure of and convey natural gas or CO_2. The two main types of compressors used in the industry are centrifugal compressors and reciprocating compressors. Subpart W currently requires Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities to calculate compressor emissions using population emission factors per existing 40 CFR 98.233(o)(10) and (p)(10). Population emission factors are multiplied by the count of equipment, in this case compressors of a certain type, to calculate emissions. For the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment industry segments, subpart W requires facilities to annually measure the emissions from the compressor sources applicable to the mode the compressor is in at the time of the measurement; facilities also have the option to continuously measure emissions from a compressor source per existing 40 CFR 98.233(o)(2) through (5) and (p)(2) through (5). The annual measurements are called ''as found'' measurements because the compressors are to be measured in the mode in which they are found when the measurements are made. The ''as found'' measurements are required for each centrifugal and reciprocating compressor at least annually, but only for those compressor emission sources that have measurement requirements for the mode in which they are found (*i.e.,* the defined ''compressor mode-source combinations''), as described in the following paragraph. If a given compressor was not measured in not-operating-depressurized-mode during the ''as found'' measurements for three consecutive years, a measurement in not-operating-depressurized-mode is currently required to be taken during the next planned scheduled shutdown of the compressor, per existing 40 CFR 98.233(o)(1)(i)(C) and (p)(1)(i)(D).

Subpart W at 40 CFR 98.238 currently defines the following ''compressor sources'': wet seal degassing vent (for centrifugal compressors only); rod packing emissions (for reciprocating compressors only); blowdown valve leakage through the blowdown vent (for both centrifugal and reciprocating compressors) and unit isolation valve leakage through the open blowdown vent without blind flanges (for both centrifugal and reciprocating compressors). Subpart W also currently defines the following ''compressor modes'': operating-mode (for both centrifugal and reciprocating compressors), standby-pressurized-mode (for reciprocating compressors only [93]), and not-operating-depressurized-mode (for both centrifugal and reciprocating compressors). Some compressor sources may only release emissions during certain compressor modes. Therefore, subpart W uses the term ''compressor mode-source combination'' to refer to the specific compressor sources that must be measured based on the mode in which the compressor is found. For centrifugal compressors, subpart W currently requires measurement in the following compressor mode-source combinations: wet seal oil degassing vents in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode. For reciprocating compressors, subpart W currently requires measurement in the following compressor mode-source combinations: rod packing emissions in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, blowdown valve leakage through the blowdown vent in standby-pressurized-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode.

[93] Currently, subpart W does not require measurements for centrifugal compressors in standby-pressurized-mode and therefore does not define this mode for centrifugal compressors.

1. Mode-Source Combination Measurement Requirements

The EPA is proposing several amendments related to the ''as found'' measurement requirements to improve the quality of data collected for compressors. First, standby-pressurized-mode was not included as a mode for centrifugal compressors in the existing subpart W definition of ''compressor mode'' and no compressor mode-source combinations were defined for centrifugal compressors in standby-pressurized-mode. While centrifugal compressors are seldom in the standby-pressurized-mode, there have been several occasions when reporters have indicated through the GHGRP Help Desk that a centrifugal compressor was in this mode during the ''as found'' measurement. Therefore, we are proposing to revise the definition of compressor mode in 40 CFR 98.238 to add standby-pressurized-mode to the defined modes for centrifugal compressors and require measurement of volumetric emissions from the wet seal oil degassing vent or dry seal vent, as applicable (see discussion in following paragraph) and the volumetric emissions from blowdown valve leakage through the blowdown vent when the compressor is found in this mode (proposed 40 CFR 98.233(o)(1)(i)(C)), consistent with section II.A of this preamble.

Second, dry seals on centrifugal compressors were not included in the existing subpart W definition of ''compressor source'' and no compressor mode-source combinations were defined for dry seals on centrifugal compressors. While emissions from wet seal oil degassing vents are expected to be larger than from dry seals when the dry seal compressor is well-maintained and operating normally, dry seals still contribute to centrifugal compressor emissions, especially if they are poorly maintained or there are unforeseen upset conditions. Additionally, the measurement crew will already be at the centrifugal compressor to make the ''as found'' measurement for blowdown valve leakage, so they can also measure the emissions from the dry seal while they are onsite. Therefore, to better characterize the emissions from dry seal centrifugal compressors, we are proposing to revise the definition of compressor source in 40 CFR 98.238 to add dry seal vents to the defined compressor sources for centrifugal compressors and require measurement of volumetric emissions from the dry seal vents in both operating-mode and in standby-pressurized-mode (proposed 40 CFR 98.233(o)(2)(iii)), consistent with section II.B of this preamble. Proposed measurement methods for the dry seal vents are similar to those provided for reciprocating compressor rod packing emissions and would include the use of temporary or permanent flow meters, calibrated bags, and high volume samplers. We are proposing that screening methods may also be used to determine if a quantitative measurement is required. We are proposing to specify that acoustical screening or measurement methods would not be applicable to screening dry seal vents because emissions from dry seal vents are not a result of through-valve leakage. These proposed revisions include a proposed new reporting requirement in proposed 40 CFR 98.236(o)(1)(x) to report the number of dry seals on centrifugal compressors and the reporting of emission measurements made on the dry seals.

Third, we are proposing to revise 40 CFR 98.233(p)(1)(i) to require measurement of rod packing emissions for reciprocating compressors when found in the standby-pressurized-mode because recent studies indicate that rod packing emissions can occur while the compressor is in this mode.[94] The inclusion of this compressor mode-source combination would more accurately reflect compressor emissions, consistent with section II.A of this preamble. Furthermore, the measurement crew will already be at the compressor to make the ''as found'' measurement for blowdown valve leakage, so they can also measure the emissions from the dry seal while they are onsite, and several reporters already make these measurements.

Fourth, as noted in section III.O of this preamble, if a given compressor was not measured in not-operating-depressurized-mode during the ''as found'' measurements for three consecutive years, a measurement in not-operating-depressurized-mode is currently required to be taken during the next planned scheduled shutdown of the compressor, per 40 CFR 98.233(o)(1)(i)(C) and (p)(1)(i)(D). This provision requires reporters to schedule an extra ''as found'' measurement to make this required measurement if the compressor was not found in this mode when the regularly scheduled ''as found'' measurements were taken. We are proposing to eliminate this requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years, consistent with section II.C of this preamble. We originally included this requirement in subpart W in order to obtain a sufficient amount of data for this mode (75 FR 74458, November 30, 2010). However, based on data collected under subpart W thus far, many compressors are in not-operating-depressurized-mode for 30 percent of the time or more, so facilities would be able to obtain sufficient number of measurements in not-operating-depressurized-mode to calculate an accurate mode-source specific emission factor without the additional requirement. As such, the extra measurements are unnecessary, and we are proposing to eliminate this requirement and make the annual ''as found'' measurements true ''as found'' measurements. We are also proposing to remove the reporting requirement to indicate if the compressor had a scheduled depressurized shutdown during the reporting year (existing 40 CFR 98.236(o)(1)(xiv) and 40 CFR 98.236(p)(1)(xiv)) because that information is only collected to verify compliance with the requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years.

2. Measurement Methods

The EPA is proposing several amendments related to the measurement method requirements to improve the quality of data collected for compressors. First, we are proposing to revise the allowable methods for measuring wet seal oil degassing vents. Since the inception of subpart W, the only method provided in 40 CFR 98.233(o)(2)(ii) for measuring volumetric flow from wet seal oil degassing vents has been the use of a temporary or permanent flow meter. The limitation in methods allowed for wet seal oil degassing vents was due to the expectation that the volumetric flows may exceed the quantitative limits of these other methods. In reviewing the data reported for the wet seal oil degassing vent, we found that the measured flow rates using flow meters are often within the limits of other measurement methods allowed for other compressor sources. We also found that many reporters have overlooked the restriction on the methods allowed for wet seal oil degassing vents and often reported using other measurement methods (*e.g.,* high volume samplers). We have found that most of these measured flow rates appear to be within the capacity limits of a typical high volume sampler. In the small minority of cases in which flow rates would be outside of the capacity limit of the instrument, facilities can use an alternate method, consistent with the requirements for other compressor source measurements. Consequently, we concluded that the measurement methods allowed for wet seal oil degassing vents could be expanded to include the use of calibrated bags and high volume samplers. Therefore, we are proposing to revise 40 CFR 98.233(o)(2)(ii) to allow the use of calibrated bags and high volume samplers. However, we are not proposing to allow the use of screening methods because wet seal oil degassing vents are expected to always have some natural gas flow. Therefore, we are proposing to retain and clarify this unique limitation on the use of screening methods for wet seal oil degassing vent measurement methods. This proposed revision would provide improved clarity of the wet seal oil degassing provisions and allow an additional measurement method that was determined to be accurate for this source, consistent with section II.B of this preamble.

Second, we are proposing to remove acoustic leak detection from the screening and measurement methods allowed for manifolded groups of compressor sources. As noted in existing 40 CFR 98.234(a)(5), acoustic leak detection is applicable only for through-valve leakage. The acoustic method can be applied to individual compressor sources associated with through-valve leakage (*i.e.,* blowdown valve leakage or isolation valve leakage), but it cannot be applied to a vent that contains a group of manifolded compressor sources downstream from the individual valves or other sources that may be manifolded together. The inclusion of this method for manifolded compressor sources was in error and we are proposing to remove it from 40 CFR 98.233(o)(4)(ii)(D) and (E) and 40 CFR 98.233(p)(4)(ii)(D) and (E) to improve accuracy of the measurements, consistent with section II.B of this preamble.

Third, we are proposing a number of clarifications to the references to the allowed measurement methods to correct errors and improve the clarity of the rule, consistent with section II.D of

[94] Subramanian, R. *et al.* ''Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol.'' *Environ. Sci. Technol.* 49, 3252–3261. 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

this preamble. These proposed revisions include: revising 40 CFR 98.233(o)(1)(i)(A) and (B) to reference 40 CFR 98.233(o)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A), (B) and (C) (as proposed) to reference 40 CFR 98.233(p)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A) and (C) (as proposed) to reference ''paragraph (p)(2)(ii) or (iii) of this section as applicable'' instead of only ''paragraph (p)(2)(ii)'' to clarify that measurement of rod packing emissions without an open-ended vent line are to be made according to 40 CFR 98.233(p)(2)(iii); and revising 40 CFR 98.233(p)(2)(ii)(C) and (iii)(A) to clarify that acoustic leak detection is not an applicable screening method for rod packing emissions (not a through-valve leakage).

3. Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting

As noted in section III.O of this preamble, subpart W requires onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to calculate compressor emissions using population emission factors. As noted in the introduction to section II of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for certain oil and natural gas sources. The proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc include emission limits for reciprocating compressors, centrifugal compressors with wet seals, and centrifugal compressors with dry seals that would apply when the compressor is in operating-mode or standby-pressurized-mode. The proposed standards would require owners or operators to conduct volumetric emissions measurements from each reciprocating compressor rod packing or centrifugal compressor wet or dry seal on or before 8,760 hours of operation from startup or from the previous measurement. Similar to the 2016 amendments to subpart W specific to equipment leak surveys (81 FR 4987, January 29, 2016), the EPA is proposing to revise the calculation methodology for compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W so that data derived from centrifugal compressor or reciprocating compressor monitoring conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 could be used to calculate emissions for subpart W reporting, consistent with section II.B of this preamble. For compressors at onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting facilities not subject to either NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, we are proposing that reporters would have the option to calculate emissions for subpart W reporting using the same provisions for ''as found'' measurements as other industry segments.

Because the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc are not the same as the requirements in subpart W, the EPA is proposing a few additional requirements under subpart W for compressors subject to the proposed standards in NSPS OOOOb or standards in an applicable approved state plan or applicable Federal plan codified in 40 CFR part 62. First, subpart W requires measurement of compressor sources that would not be required to be measured under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc (*e.g.,* blowdown valve leakage through the blowdown vent). The EPA is proposing that reporters conducting measurements of compressors under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would conduct measurements of any other compressor sources required to be measured by subpart W at the same time. Second, because the time between measurements under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc may not result in measurements being taken every reporting year, the EPA is proposing to specify that reporters would use equation W–22 or equation W–27, as applicable, to calculate emissions from all mode-source combinations for any reporting year in which measurements are not required. Finally, while we are proposing to eliminate the requirement to conduct a measurement in not-operating-depressurized-mode at least once every 3 years for compressors in the industry segments for which reporters are currently required to conduct ''as found'' measurements (as described in section III.O.1 of this preamble), we note that the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc would only require measurements to be taken in operating-mode or standby-pressurized-mode. If no compressor sources are measured in not-operating-depressurized-mode, reporters would not have data to develop reporter emission factors for that mode-source combination using equation W–23 and equation W–28. Therefore, we are proposing in 40 CFR 98.233(o)(10)(i)(B) and 40 CFR 98.233(p)(10)(i)(B) that reporters with compressors subject to NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would be required to conduct additional measurements of compressors in not-operating-depressurized-mode such that they can develop an annual reporter emission factor for isolation valve leakage in not-operating-depressurized-mode. Based on an analysis of all reciprocating and centrifugal compressor measurements for the other industry segments since 2015, approximately one-third of all compressor measurements were performed in not-operating-depressurized mode. We propose to maintain that percentage for reciprocating and centrifugal compressor measurements in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. Therefore, we are proposing to require reporters to measure emissions in not-operating-depressurized mode from isolation valve leakage for at least one-third of the subject compressors during any 3 consecutive calendar year period. We are also proposing to require reporters to provide the total count of compressors measured in not-operating-depressurized-mode over the previous 3 calendar years, as well as the total number of compressors subject to NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62. We request comment on other ways to collect sufficient measurements to calculate a reporter emission factor for isolation valve leakage in not-operating-depressurized-mode.

For facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments that do not conduct measurements, we are proposing to clarify the language at 40 CFR 98.233(o)(10) and (p)(10) for compressors at Onshore Petroleum and Natural Gas Production or Onshore

Petroleum and Natural Gas Gathering and Boosting facilities, consistent with section II.B of this preamble. The compressor emission factors for these industry segments are specific to uncontrolled wet seal oil degassing vents on centrifugal compressors and uncontrolled rod packing emissions for reciprocating compressors. The language in 40 CFR 98.233(o) and (p) clearly indicates that the provisions of 40 CFR 98.233(o)(10) and (p)(10) do not apply for controlled compressor sources. However, proposed revisions are necessary to provide clarity regarding the compressor sources for which emissions are required to be calculated under 40 CFR 98.233(o)(10) and (p)(10) and reported under 40 CFR 98.236(o)(5) and (p)(5). Specifically, we are proposing minor revisions to 40 CFR 98.233(o)(10) and the corresponding reporting requirements in 40 CFR 98.236(o)(5) to clarify that the compressor count used in equation W–25 should be the number of centrifugal compressors with atmospheric (*i.e.,* uncontrolled) wet seal oil degassing vents. Similarly, we are proposing minor revisions to 40 CFR 98.233(p)(10) and the corresponding reporting requirements in 40 CFR 98.236(p)(5) to clarify that the compressor count used in equation W–29D should be the number of reciprocating compressors with atmospheric (*i.e.,* uncontrolled) rod packing emissions. We are also proposing to add requirements to report the total number of centrifugal compressors at the facility and the number of centrifugal compressors that have wet seals to 40 CFR 98.236(o)(5) and proposing to add a requirement to report the total number of reciprocating compressors at the facility to 40 CFR 98.236(p)(5). These additional data would provide the EPA with an improved understanding of the total number of compressors and the number of compressors that are controlled (*i.e.,* routed to flares, combustion, or vapor recovery systems) in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, consistent with section II.C of this preamble.

In addition, consistent with section II.B of this preamble, we are proposing to amend the CH_4 and CO_2 population emission factors in equation W–29D for reciprocating compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities. The current population emission factors were adopted from the 1996 GRI/EPA study *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks.*[95] [96] In the time since the promulgation of the current population emission factor, Zimmerle *et al.* (2019) [97] reported the results of a nationally representative field assessment of equipment leak rates from facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. As part of this proposed rulemaking, the EPA reviewed Zimmerle *et al.* (2019) to evaluate the potential for revisions to the population emission factor in equation W–29D. We found that Zimmerle *et al.* (2019) uses a larger and more representative sample of 412 rod packing vent measurements, compared to the 40 compressor measurements available in the 1996 GRI/EPA study. Therefore, we are proposing a population emission factor for CH_4 based on the average population emission rate measured by Zimmerle *et al.* (2019), with a proposed CO_2 population emission factor derived by applying the ratio of the current CO_2 emission factor to the current CH_4 emission factor to the CH_4 emission factor obtained from Zimmerle *et al.* (2019). For more information regarding our review of Zimmerle *et al.* (2019) and the derivation of the proposed emission factors, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. We request comment on whether there are other studies or data sets that provide information that could be used to further refine the emission factors for both reciprocating and centrifugal compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, particularly data sets that include measurements for all compressor sources (*i.e.,* rod packing and blowdown isolation valves for reciprocating compressors and wet seals, dry seals, and blowdown isolation valves for centrifugal compressors).

4. Compressors Routed to Controls

Centrifugal and reciprocating compressors are the only sources for which capture for fuel use and thermal oxidizers currently are specifically listed as dispositions for emissions that would otherwise be vented (see 40 CFR 98.233(o) and (p) introductory text). The EPA's intent with the provisions is to differentiate flares, which are combustion devices that combust waste gases without energy recovery (per 40 CFR 98.238), from combustion devices with energy recovery, including for fuel use. However, some thermal oxidizers combust waste gases without energy recovery and therefore may instead meet the subpart W definition of flare. Consistent with section II.D of this preamble, in order to emphasize that the EPA's intent is generally to treat emissions routed to flares and combustion devices other than flares consistently, we are proposing to remove the references to fuel use and to thermal oxidizers in 40 CFR 98.233(o) and (p) and 40 CFR 98.236(o) and (p). Instead, we are proposing to define ''routed to combustion'' in 40 CFR 98.238 to specify the types of non-flare combustion equipment for which reporters would be expected to calculate emissions. In particular, for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments, ''routed to combustion'' would mean the combustion equipment specified in 40 CFR 98.232(c)(22), (i)(7), and (j)(12), respectively (*i.e.,* the combustion equipment for which emissions must be calculated per 40 CFR 98.233(z)). For all other industry segments, ''routed to combustion'' would mean the stationary combustion sources subject to subpart C. The proposed definition of ''routed to combustion'' would apply for all subpart W emission sources for which that term appears (*e.g.,* natural gas driven pneumatic pumps).

5. Reporting of Compressor Activity Data

We are proposing to remove some data elements that are redundant between 40 CFR 98.236(o)(1) and (2) for centrifugal compressors and between 40 CFR 98.236(p)(1) and (2) for reciprocating compressors. Specifically, current 40 CFR 98.236(o)(1)(vi) and 40 CFR 98.236(p)(1)(viii) require reporters to indicate which individual compressors are part of a manifolded

[95] The development of the current emission factors for reciprocating compressors in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting sectors are described in *Compressor Modes and Thresholds*, U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3580), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[96] Campbell, L., M. Campbell, M. Cowgill, D. Epperson, M. Hall, M. Harrison, K. Hummell, D. Myers, T. Shires, B. Stapper, C. Stapper, J. Wessels, AND H. Williamson. *Methane Emissions From the Natural Gas Industry—Volume 8. Equipment Leaks.* U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–96/080h, also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[97] Zimmerle, D., Bennett, K., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., & Allen, D. (2019). Characterization of methane emissions from gathering compressor stations: final report. Mountain Scholar. *https://doi.org/10.25675/10217/194544.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

group of compressor sources, and current 40 CFR 98.236(o)(1)(vii) through (ix) and 40 CFR 98.236(p)(1)(ix) through (xi) require reporters to indicate whether individual compressors have compressor sources routed to flares, vapor recovery, or combustion. However, current 40 CFR 98.236(o)(2)(ii)(A) and 40 CFR 98.236(p)(2)(ii)(A) require the same information for each compressor leak or vent rather than by compressor. The information collected for each leak or vent is more detailed and is the information used for emissions calculations. Therefore, the EPA is proposing to remove the redundant reporting requirements in existing 40 CFR 98.236(o)(1)(vi) through (ix) and existing 40 CFR 98.236(p)(1)(viii) through (xi), consistent with section II.B of this preamble.

P. Equipment Leak Surveys

Subpart W reporters are currently required to quantify emissions from equipment leaks using the calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count). The equipment leak survey method currently uses the count of leakers detected with one of the subpart W leak detection methods in 40 CFR 98.234(a), subpart W leaker emission factors, and operating time to estimate the emissions from equipment leaks. The current leaker emission factors applicable to onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities are found in existing Table W–1E of subpart W. These leaker emission factors are based on the EPA's *Protocol for Equipment Leak Emission Estimates* published in 1995 (Docket Id. No. EPA–HQ–OAR–2009–0927–0043), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. The leaker emission factors are provided for components in gas service, light crude service, and heavy crude service that are found to be leaking via several different screening methods. In addition to being component- and service-specific, subpart W currently provides two different sets of leaker emission factors: one based on leak rates for leaks identified by Method 21 (see 40 CFR part 60, appendix A–7) using a leak definition of 10,000 ppm and one based on leak rates for leaks identified by Method 21 using a leak definition of 500 ppm. Currently, the other leak screening methods provided in subpart W (OGI, infrared laser beam illuminated instrument, and acoustic leak detection device) use the leaker emission factors based on Method 21 data with a leak definition of 10,000 ppm.

1. Revisions and Addition of Default Leaker Emission Factors

In the 2022 Proposed Rule, we proposed to revise the leaker emission factors to provide separate leaker factors for leaks detected using OGI based on recent study data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019). For the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the emission factors were calculated directly from these study data. For downstream industry segments, separate OGI emission factors were estimated using an ''OGI enhancement factor,'' which was estimated as the ratio between the OGI emission factors and the Method 21 emission factors for the upstream industry segments. In this proposed rulemaking and as described in more detail later in this section, we are maintaining our proposal to provide separate emission factors for leaks detected using OGI based on recent study data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019). In this proposed rulemaking, we are proposing an update to the emission factors provided for downstream segments based on an ''OGI enhancement factor'' value that has been updated since the June 2022 proposal. Additionally, in this rulemaking we are proposing to use the Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) study data to provide Method 21 at leak definitions of 500 ppm and 10,000 ppm. We expect these updated emission factors to provide a more accurate estimation of emissions estimated with default leaker emission factors as they use more recent data and are from a dataset of a larger size than the current emission factors.

In the years that have followed the adoption of the leaker emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks that provide measurement data to update the existing emission factors for leaks detected using Method 21 at a leak definition of either 10,000 ppm or 500 ppm as well as to quantify leaker emission factors for OGI screening methods at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.[98] With respect to the OGI screening method, these studies have found that OGI identifies fewer yet larger leaks than the EPA's Method 21. Specifically, the average leaker emission factor determined from OGI leak detection surveys is often a factor of two or more larger than leaker emission factors determined when using Method 21 leak detection surveys. Therefore, the application of the same leaker emission factor to leaking components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in subpart W, likely understates the emissions from leakers detected with OGI.

Based on our review of these studies, we are proposing to amend the leaker emission factors in existing Table W–1E (proposed Table W–2) for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to update the Method 21 emission factors as well as include separate emission factors for leakers detected with OGI, consistent with section II.B of this preamble. We are proposing to revise the emission factors using study data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019). The Zimmerle *et al.* (2020) study contains hundreds of quantified leaks detected using OGI. The Pacsi *et al.* (2019) study also contains hundreds of equipment leak measurements from sites that were screened using Method 21 with a leak definition of 10,000 ppm and 500 ppm as well as OGI. We are proposing the use of these studies as the basis for the proposed emission factors because they included recent measurements of subpart W-specified equipment leak components from both oil and gas production and gathering and boosting sites in geographically diverse locations.

As noted above, numerous studies have found that the average size of the leaks detected by OGI are larger than those detected by EPA's Method 21. Using the Pacsi *et al.* study data, we estimate that the leaks detected by OGI are 1.63 times larger than leaks detected by Method 21 at a leak definition of

[98] See, *e.g.,* ERG (Eastern Research Group, Inc.) and Sage (Sage Environmental Consulting, LP). *City of Fort Worth Natural Gas Air Quality Study: Final Report.* July 13, 2011, available at *https://www.fortworthtexas.gov/departments/development-services/gaswells/air-quality-study/final*; Allen, D.T., *et al.* ''Measurements of methane emissions at natural gas production sites in the United States.'' *Proceedings of the National Academy of Sciences of the United States of America*, Vol. 110, no. 44. pp. 17768–17773, October 29, 2013, available at *http://dept.ceer.utexas.edu/methane/study.* Docket Item No. EPA–HQ–OAR–2014–0831–0006; Pacsi, A.P., *et al.* ''Equipment leak detection and quantification at 67 oil and gas sites in the Western United States.'' *Elem Sci Anth*, 7: 29, available at *https://doi.org/10.1525/elementa.368.* 2019; Zimmerle, D., *et al.* ''Methane Emissions from Gathering Compressor stations in the U.S.'' *Environmental Science & Technology* 2020, 54(12), 7552–7561, available at *https://doi.org/10.1021/acs.est.0c00516.* The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

10,000 ppm and 2.81 times larger than leaks detected by Method 21 at a leak definition of 500 ppm. As noted, the Pacsi *et al.* (2019) study provided data on leaks detected by Method 21 at a leak definition of 10,000 ppm and 500 ppm as well as OGI data, however, the sample size of leaks screened in the Pacsi *et al.* (2019) study with Method 21 is smaller than those screened with OGI, particularly when combining the OGI data from Pacsi *et al.* (2019) with the Zimmerle *et al.* (2020) data. The combined OGI dataset from Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) contains more than 700 measurements from leaks detected with OGI. Emission factors using these data are derived for each combination of well site type (*e.g.,* gas or oil) and component type (*e.g.,* valve). The more than 700 measurements in the combined OGI dataset results in an average of 44 measurements for each combination of well site type (*e.g.,* gas or oil) and component type (*e.g.,* valve). In contrast, the Pacsi *et al.* study has nearly 300 measurements for leaks detected using Method 21 at a leak definition of 500 ppm and 140 measurements for leaks detected using Method 21 at a leak definition of 10,000 ppm, which results in averages of 21 measurements and 10 measurements for each combination of site type and component type, respectively.

For OGI, we are proposing leaker emission factors that were developed using the combined data from Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) by site type (*i.e.,* gas or oil). Equipment leaks are inherently variable; therefore, sample size is important when seeking to derive representative equipment leak emission factors. Therefore, we are proposing to use the OGI data and the ratio between OGI and the Method 21 at a leak definition of 10,000 ppm and a leak definition of 500 ppm (*i.e.,* 1.63 and 2.81, respectively) to derive the proposed emission factors for Method 21 at both leak definitions. This approach uses the most robust set of data available (OGI) to derive the proposed emission factors. The precise derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors in proposed Table W–2 would be used to quantify the emissions from the leaks identified using these other monitoring methods. We are seeking comment on the performance of infrared laser beam illuminated instruments and acoustic leak detection devices including data that may support a separate detection method specific emission factor or that supports the proposal that OGI emission factors appropriately estimate leakers detected with these methods.

As described in the introductory section III.P of this section of this preamble, currently, equipment leak emissions quantified with the leaker method are calculated using the count of leakers and a default emission factor from existing Table W–1E that is specific to the type of component (*e.g.,* valve) and the service (*i.e.,* gas or oil). For onshore petroleum and natural gas gathering and boosting facilities, subpart W currently specifies and would continue to specify that all components should be considered to be in gas service consistent with the language in 40 CFR 98.233(q)(2)(iv); thus, the gas service factors from proposed Table W–2 should be applied to the count of equipment leak components consistent with the leak detection method used.

For onshore petroleum and natural gas production facilities, we are proposing to amend 40 CFR 98.233(q)(2)(iii) to state that onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors consistent with the well type (rather than the component-level service type), where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in proposed Table W–2 to this subpart. This proposed amendment is intended to ensure that the application of the proposed emission factor using the well site type rather than component-level service type is consistent with the derivation of the emission factor. The emission factors were derived based on study-reported well site type, accounting for the idea that a gas well site can have components in oil service and vice versa, and thus would be required to be applied by well site type.

As described previously, our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates that the OGI screening method finds fewer and larger leaks than Method 21. Consequently, the leaker emission factors derived using measurement data from the OGI screening method are larger than those derived using the measurement data from Method 21 screening method. We expect that the leaker emission factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks. In this proposal, we are applying the addition of an ''OGI enhancement factor'' to the leaker emission factors for the other subpart W industry segments, resulting in new proposed emission factors, to ensure that facilities estimate the same equipment leak emissions if they either (1) identify leaks with Method 21 and apply the Method 21 derived emission factors or (2) identify leaks with OGI and apply the OGI enhancement factor adjusted emission factors. More specifically, we are proposing to apply the ''OGI enhancement'' factor identified from measurement study data in the onshore production and gathering and boosting industry segments, a value of 1.63, to the leaker emission factors for the other subpart W industry segments as a means to estimate and propose an OGI emission factor set. In other words, the ''OGI enhancement factor'' is based on the average OGI-identified leak being 1.63 times larger than the average Method 21-identified leak when using a leak definition of 10,000 ppm in the measurement study data. Analogous to the proposed changes in proposed Table W–2 for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, this results in the proposed addition of emission factor sets specific to OGI, infrared laser beam illuminated instrument, or acoustic leak detection device screening methods. The proposed emission factor sets are included in proposed Tables W–4 and W–6 for the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, and Natural Gas Distribution industry segments. A detailed description of the proposed emission factors is provided in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

The existing reporting requirements for the equipment leak emission source types that are quantified by leaker method include activity and emissions data (*i.e.*, count of leakers, annual average operating time, CO_2 emissions and CH_4 emissions) on a per component basis (*e.g.*, valve, connector), consistent with the component-level screening surveys and component-level default emission factors. In addition to continuing to collect the existing activity data, we are seeking comment on including a requirement to report the major equipment type (*e.g.*, wellhead, compressor, dehydrator) at which the component-level leak is found. The collection of the major equipment type associated with leakers could facilitate future development of major equipment-based leaker factors and/or be combined with the population of major equipment at facilities to facilitate future development of the major equipment population emission factors. Since the leak surveys are ground-level, the major equipment type is expected to be known and this additional requirement would appear to result in minimal increased burden. We are seeking comment on whether it is appropriate to require the reporting of the type of major equipment type in addition to the component type and specifically if there are concerns regarding burden or data collection that should be considered.

2. Addition of Undetected Leak Factor for Leaker Emission Estimation Methods

Subpart W currently provides various screening methods for detecting leaking components in 40 CFR 98.234(a). Each method includes a unique instrument and associated procedure by which leaks are detected. Variability inherently exists in each method's ability to detect leaks and can be attributed to reasons associated with the instrument, leak detection procedures, the operator or site conditions. For example, some components may be inaccessible to be surveyed with handheld devices that require close proximity to the leak to detect it (*e.g.*, Method 21 flame ionization detectors (FID)), while the same leak could be visualized using an OGI camera that is less dependent on proximity to the leak. Operators with varying levels of training or expertise deploy the screening devices, resulting in operator variability. Site-level conditions such as wind speed can also impact the detection of leaks. We have reviewed recent study data from Pacsi *et al.* (2019) in which multiple leak detection methods, including OGI and Method 21, were deployed alongside one another at the same sites. This study demonstrates that there are undetected leaks for each method. Based on the Pacsi *et al.* (2019) study data, OGI observes 80 percent of emissions from measured leaks, Method 21 at a leak definition of 10,000 ppm observes 65 percent of emissions from measured leaks, and Method 21 at leak definition of 500 ppm observes 79 percent of emissions from measured leaks. In order to account for the quantity of emissions that remain undetected by each screening method, we are proposing to provide a method specific adjustment factor, k, for the calculation methods used to quantify emissions from equipment leaks using the leaker method in 40 CFR 98.233(q). The proposed addition of a method specific adjustment factor would be expected to improve the accuracy of emissions data, consistent with section II.B of this preamble. Further detail on the development of the adjustment factor for each of these screening methods is provided in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

As noted in section III.P.2 of this preamble, very few onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys, so there are no data available to develop a method-specific adjustment factor, k, for these detection methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using OGI. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI adjustment factor, k, would be used in the calculation to quantify the emissions from the leaks identified using these other monitoring methods. We are seeking comment on the performance of infrared laser beam illuminated instruments and acoustic leak detection devices, including data that may support a separate detection method specific adjustment factor, k.

We are proposing the survey method-specific k value in equation W–30 of 40 CFR 98.233(q)(2) such that the factor would be applied to the emissions quantified using either the default or the proposed site-specific emission factors, as discussed in section III.P.4 of this preamble, to estimate equipment leak emissions. We are also proposing the application of the k value to the emissions quantified using the proposed direct measurement method discussed in section III.P.3 of this preamble and in proposed 40 CFR 98.233(q)(3). The application of the k factor is intended to account for undetected emissions such that the reported emissions represent the actual site-level total, not limited to the fraction of detected leaks. We are seeking comment on the application of this factor to scale detected leak emissions. Specifically, we are seeking additional data that either support the application of this factor and the appropriate method-specific value for this factor or support why the proposed factor should not be applied to equipment leak emission estimates.

3. Addition of Method To Quantify Emissions Using Direct Measurement

As an alternative to the proposed revised default leaker emission factors, we are also proposing in 40 CFR 98.233(q)(1) to provide an option (provided in proposed 40 CFR 98.233(q)(3)) that would allow reporters to quantify emissions from equipment leak components in 40 CFR 98.233(q) by performing direct measurement of equipment leaks and calculating emissions using those measurement results, consistent with section II.B of this preamble. The proposed amendments would provide that facilities with components subject to 40 CFR 98.233(q) can elect to perform direct measurement of leaks using one of the existing subpart W measurement methods in 40 CFR 98.234(b) through (d), such as calibrated bagging or a high volume sampler. To use this proposed option, all leaks identified during a ''complete leak detection survey'' must be quantified; in other words, reporters could not use leaker emission factors for some leaks and quantify other leaks identified during the same leak detection survey. For the Onshore Petroleum and Natural Gas Production industry segment, proposed 40 CFR 98.233(q)(1) specifies that a complete leak detection survey would be the fugitive emissions monitoring of a well site using a method in 40 CFR 98.234(a) which is conducted to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment on a single well-pad. For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, proposed 40 CFR 98.233(q)(1) specifies that a complete leak detection survey would be the fugitive emissions monitoring of a compressor station using a method in 40 CFR 98.234(a) which is conducted to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment at a ''gathering and boosting site'' (and we are proposing to define this term in 40 CFR 98.238, as described in section III.D of this preamble). For downstream industry segments (*e.g.*, Onshore Natural Gas Transmission Compression), a complete leak detection survey is facility-wide, and therefore, the election to perform direct measurement of leaks would also be facility-wide. In other words, this option would allow the use of measurement data directly when all leaks identified are quantitatively measured.

The proposed amendments rely specifically on quantitative measurement methods already provided in the rule. We are seeking comment on alternative methods for quantifying leaks for use for these equipment leak measurements (and for ''as found'' compressor measurements) along with supporting information and data. The supporting information should include description of the method, limitations on the applicability of the method, and calibration requirements. Supporting data should include accuracy assessments (*e.g.*, controlled release assessments) relative to other quantitative measurement methods provided in the rule.

4. Addition of a Method To Develop Site-Specific Component-Level Leaker Emission Factors

As noted in section III.P of this preamble, facilities are currently required to perform leak surveys to determine the number of leaking components. The results of these surveys (*i.e.*, the count of leakers) are used with default emission factors to estimate the quantity of resulting emissions. As noted in the previous section, the EPA is proposing an additional option for facilities to conduct leak surveys and perform direct measurement to quantify the emissions from equipment leak components.

The EPA recognizes that while direct measurement is the most accurate method for determining equipment leak emissions, it may also be time consuming and costly. In consideration of both the advantages of and potential burdens associated with direct measurement, the EPA is also proposing to provide facilities with a method to use direct measurement from leak surveys to develop component level emission factors based on site-specific leak measurement data. The site-specific emission factors would provide increased accuracy over the use of default emission factors, consistent with section II.B of this preamble, while lessening a portion of the burden of directly measuring every leak.

We are proposing that facilities that elect to follow the direct measurement provisions in proposed 40 CFR 98.233(q)(3)(i) must track the individual measurements of natural gas flow rate by specific component type (valve, connector, etcetera, as applicable for the industry segment) and leak detection method. We are proposing three different bins for the leak detection methods: Method 21 using a leak definition of 500 ppm as specified in 40 CFR 98.234(a)(2)(i); Method 21 using a leak definition of 10,000 ppm as specified in 40 CFR 98.234(a)(2)(ii); and OGI and other leak detection methods as specified in 40 CFR 98.234(a)(1), (3), or (5). We are proposing that reporters would have to compile at least 50 individual measurements of natural gas flow rate for a specific component type and leak detection method (*e.g.*, gas service valves detected by OGI) before they can develop and use the site-specific emission factors for the component types at the facility. We are proposing that these flow rate measurements would be required to be converted to standard conditions following the procedures in 40 CFR 98.233(t). We are proposing that the volumetric measurements comprised of at least 50 measured leakers must then be summed and divided by the total number of leaks measurements for that component type and leak detection method combination. The resulting value would be an emission factor in units of standard cubic feet per hour-component (scf/hr-component). The site-specific emission factor is proposed to be used, when available, to calculate equipment leak emissions following the procedures in 40 CFR 98.233(q)(2). Because some equipment component types are more prevalent and more likely to reach 50 leak measurements than other components, application of the calculation methodology in 40 CFR 98.233(q)(2) may include a default leaker factors for some components and site-specific leaker factors for other components.

For example, a hypothetical onshore petroleum and natural gas production facility has 30 single well-pad sites, at which during a reporting year they perform complete leak surveys of all components and direct measurements of all components found leaking at 20 of the single well-pad sites and they perform leak detection surveys only (*i.e.*, no measurement) at the remaining 10 single well-pad sites. In this example, during the leak detection surveys at the 20 sites where measurements were also performed, the facility obtained sufficient measurements from valves (*i.e.*, more than 50 measurements) to develop a site-specific emission factor in accordance with proposed 40 CFR 98.233(q)(4). They did not measure enough components, however, of any other type (*e.g.*, connector, open-ended line, pressure relief valve) to develop site-specific emission factors for these components. For this example, under the proposed provisions the facility must use the methods in 40 CFR 98.233(q)(1) and (3) to quantify emissions for that reporting year. The facility would be required to quantify emissions from the 20 monitored and directly measured single well-pad sites in accordance with proposed 40 CFR 98.233(q)(3). Beginning in the reporting year the measurements were made, the facility must develop and apply the site-specific emission factor for valves to any valve found leaking which was not directly measured (*i.e.*, valves at the 10 sites where only leak surveys and no measurements were performed) rather than applying the default emission factor. This facility would quantify emissions from the 10 single well sites where no measurement was performed using the count of components found leaking and the default leaker emission factors for all components in accordance with 40 CFR 98.233(q)(1) except valves, where the site-specific emission factor must be used. If in subsequent reporting years, the facility is required to perform additional surveys or elects to continue to survey and perform direct measurement, the facility will accumulate additional measurements which may be of a sufficient number to develop other component type site-specific emission factors. We also note that in accordance with proposed 40 CFR 98.233(q)(4), any additional measurements of a component for which a facility has developed a site-specific emissions factor (*e.g.*, valves in the described example) would be required to be used to update the site-specific emission factor annually.

We are proposing to require the use of a minimum of 50 measurements to ensure a statistically representative dataset. We have found that equipment leak measurements are highly variable and it is imperative to ensure a robust sample size. We have performed statistical analyses with measurements from compressors and determined that a minimum of 50 measurements is required to reduce uncertainty to factor of 3 of the true value.[99] We are seeking comment on the required number of measurements by component type and leak detection method, specifically on whether the number is or is not appropriate, whether a different number is appropriate, and the supporting rationale.

We are also proposing in 40 CFR 98.236(q) to require that the emissions be reported at the aggregation of calculated or measured values for the combination of component type and leak detection method. As discussed in more detail in section III.P.1 of this preamble, numerous studies have shown that different leak detection methods identify different populations of leaking components; therefore, consistent with the delineation of the default emission factors by leak detection method, site-specific emission factors are proposed to be delineated in the same way.

5. Removal of Additional Method 21 Screening Survey for Other Screening Survey Methods

We are proposing to remove the additional Method 21 screening when a survey is conducted using a method other than Method 21. Currently, facilities using survey methods other than Method 21 to detect equipment leaks may then screen the equipment identified as leaking using Method 21 to determine if the leak measures greater than 10,000 parts per million by volume (ppmv) (see, *e.g.*, 40 CFR 98.234(a)(1)). If the Method 21 screening of the leaking equipment is less than 10,000 ppmv, then reporters may consider that equipment as not leaking. In the 2016 subpart W revisions, we added a leak detection methodology at 40 CFR 98.234(a)(6) (proposed 40 CFR 98.234(a)(1)(ii) in this proposal) for using OGI in accordance with NSPS OOOOa, which does not include an option for additional Method 21 screening. As noted in response to comments on the subpart W proposal regarding the absence of this optional additional Method 21 screening when using OGI in accordance with NSPS OOOOa, the additional screening of OGI-identified leaking equipment using Method 21 requires additional effort from reporters (81 FR 86500, November 30, 2016). Furthermore, as noted previously in this section, the average emissions of leakers identified by OGI are greater than leaks identified by Method 21. Directly applying the number of OGI-identified leaks to the subpart W leaker emission factor specific to that survey method would provide the most accurate estimate of emissions, while selectively screening OGI-identified leaks using Method 21 to reduce the number of reportable leakers would yield a low bias in the reported emissions. Additionally, this would be incongruous with the proposed application and supporting rationale of the proposed monitoring method-specific adjustment factor, k (where the k value for Method 21 with a leak definition of 10,000 ppm would need to be applied) if OGI-identified leaks could be considered non-leaks based on subsequent Method 21 monitoring. Therefore, we are proposing to require reporters to directly use the leak survey results for the monitoring method used to conduct the complete leak survey and are proposing to eliminate this additional Method 21 screening provision. These proposed amendments are expected to provide more accurate emissions data, consistent with section II.B of this preamble.

6. Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60

As noted in the introduction to section II. of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for certain oil and natural gas new and existing affected sources, respectively. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc, owners and operators would be required to implement a fugitive emissions monitoring and repair program for the collection of fugitive emissions components at well site, centralized production facility and compressor station affected sources. In addition, the proposed NSPS OOOOb and EG OOOOc include a proposed appendix K to 40 CFR part 60, specifying an OGI-based method for detecting leaks and fugitive emissions from all components that is not currently provided in subpart W. The EPA also proposed provisions in NSPS OOOOb and EG OOOOc for equipment leak detection and repair at onshore natural gas processing facilities. Similar to the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA is proposing to revise the calculation methodology for equipment leaks in subpart W so that data derived from equipment leak and fugitive emissions monitoring using one of the methods in 40 CFR 98.234(a) which is conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would be used to calculate emissions, consistent with section II.B of this preamble.

First, under these proposed amendments, facilities with certain fugitive emissions components at a well site, centralized production facility or compressor station subject to NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 would use the data derived from the NSPS OOOOb or applicable 40 CFR part 62 fugitive emissions requirements along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report their GHG emissions to the GHGRP. Specifically, the proposed amendments would expand the existing cross-reference to 40 CFR 60.5397a to also include the analogous requirements in NSPS OOOOb or 40 CFR part 62. Facilities with fugitive emissions components not subject to the standards in the proposed NSPS OOOOb or addressed by standards in a state or Federal plan following finalization of the proposed EG OOOOc would continue to be able to elect to calculate subpart W equipment leak emissions using the leak survey calculation methodology and leaker emission factors (as is currently provided in 40 CFR 98.233(q)). Therefore, reporters with other fugitive emission sources at subpart W facilities not covered by NSPS OOOOb or a state or Federal plan in 40 CFR part 62 (*e.g.*, sources subject to other state regulations and sources participating in the Methane Challenge Program or other voluntarily implemented programs) would continue to have the opportunity to voluntarily use the proposed leak detection methods to calculate and report their GHG emissions to the GHGRP. To facilitate this proposed requirement, we are also proposing to clarify in proposed 40 CFR 98.233(q)(1)(vi)(B) and (C) that fugitive emissions monitoring conducted using one of the methods in 40 CFR 98.234(a) to comply with NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, respectively, is considered a ''complete leak detection survey,'' so that onshore petroleum and natural gas

[99] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule*. November 2016. Docket Item No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

production and onshore petroleum and natural gas gathering and boosting facilities would be able to comply with the proposed requirement to use NSPS OOOOb or 40 CFR part 62 fugitive emission surveys directly for their subpart W reports. We are also proposing to move the specification that fugitive emissions monitoring conducted to comply with NSPS OOOOa is considered a ''complete leak detection survey'' from existing 40 CFR 98.233(q)(2)(i) to proposed 40 CFR 98.233(q)(1)(vi)(A) so that all the provisions regarding what constitutes a ''complete leak detection survey'' are together. In a corresponding amendment, we are also proposing to expand the current reporting requirement in existing 40 CFR 98.236(q)(1)(iii) (proposed 40 CFR 98.236(q)(1)(iv)) to require reporters to indicate if any of the surveys of well sites, centralized production facilities or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.[100] We request comment on these proposed amendments and whether there are other provisions or reporting requirements relative to NSPS OOOOb or EG OOOOc that we should consider for revisions to requirements under subpart W.

Second, we are proposing to revise 40 CFR 98.234(a) to clarify and consolidate the requirements for OGI and Method 21 in 40 CFR 98.234(a)(1) and (2), respectively. In the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA added 40 CFR 98.234(a)(6) and (7) to provide OGI and Method 21 as specified in NSPS OOOOa as leak detection survey methods. In part, structuring the amendment this way allowed the EPA to provide the NSPS OOOOa leak detection methods as allowable methods under subpart W without affecting the requirements for facilities and industry segments not subject to NSPS OOOOa. However, as the EPA continues to propose additional standards with slightly different variations on OGI and Method 21, it would be unnecessarily convoluted organizationally to continue to add those methods and cross-references to each standard to the end of 40 CFR 98.234(a). Therefore, the EPA is proposing to move 40 CFR 98.234(a)(1) and 40 CFR 98.234(a)(6) to 40 CFR 98.234(a)(1)(i) and 40 CFR 98.234(a)(1)(ii), respectively, which would consolidate the OGI-based methods in 40 CFR 98.234(a)(1). Similarly, the EPA is proposing to revise 40 CFR 98.234(a)(2) such that 40 CFR 98.234(a)(2)(i) is Method 21 with a leak definition of 10,000 ppm and 40 CFR 98.234(a)(2)(ii) is Method 21 with a leak definition of 500 ppm. This proposed amendment would effectively move 40 CFR 98.234(a)(7) to 40 CFR 98.234(a)(2)(ii). We are also proposing that the references to ''components listed in § 98.232'' would be replaced with a more specific reference to 40 CFR 98.233(q)(1). The references to specific provisions in 40 CFR 60.5397a in 40 CFR 98.234(a)(6) and (7) would be moved to 40 CFR 98.234(a)(1)(ii) and 40 CFR 98.234(a)(2), as applicable.

In December 2022, the EPA proposed in NSPS OOOOb and EG OOOOc that owners and operators of natural gas processing facilities would detect leaks using an OGI-based monitoring method following the concurrently proposed appendix K to 40 CFR part 60. We are proposing to include that same method in subpart W at 40 CFR 98.234(a)(1)(iii) to ensure that reporters of those facilities would be able to comply with the proposed subpart W requirement to use data derived from the NSPS OOOOb or 40 CFR part 62 fugitive emissions requirements for purposes of calculating emissions from equipment leaks. In addition, as part of the December 2022 proposal of NSPS OOOOb and EG OOOOc, the EPA proposed an alternative screening approach for fugitive emissions from well sites, centralized production facilities and compressor stations that would allow the use of advanced measurement technologies to detect large equipment leaks. Under the NSPS OOOOb and EG OOOOc proposal, if emissions are detected using one of these advanced technologies, facilities would be required to conduct monitoring using OGI or Method 21 to identify and repair specific leaking equipment. Additionally, under the NSPS OOOOb and EG OOOOc proposal, even if no emissions are identified during a screening survey, some facilities using these advanced technologies would still be required to conduct annual fugitive emissions monitoring using OGI. The EPA's intent in this proposed rule for subpart W is that the results of those NSPS OOOOb and 40 CFR part 62 OGI or Method 21 surveys would be used for purposes of calculating emissions for subpart W, as OGI and Method 21 are capable of identifying leaks from individual components and they are leak detection methods provided in subpart W. The EPA also requests comment on additional methods or advanced technologies that can identify individual leaking components. Based on the information received, the EPA would need to review the specific method and leak detection data collected using that method to determine what default leaker emission factors would apply for that method and whether any adjustments might be needed to the subpart W equipment leak survey calculation methodology when using that method. Following that review, the EPA may undertake a future rulemaking process to include the additional leak detection method(s) in 40 CFR 98.234(a).

Third, we are proposing subpart W requirements for onshore natural gas processing facilities consistent with certain requirements for equipment leaks in the proposed NSPS OOOOb or EG OOOOc. Currently, onshore natural gas processing facilities must conduct at least one complete survey of all the components listed in 40 CFR 98.232(d)(7) each year, and each complete survey must be considered when calculating emissions according to 40 CFR 98.233(q)(2). Under the equipment leak detection and repair program included in proposed NSPS OOOOb and the EG OOOOc presumptive standards, different component types may be monitored on different frequencies, so all equipment at the facility is not always monitored at the same time. According to the current requirements in 40 CFR 98.233(q), surveys that do not include all of the applicable equipment at the facility are not considered complete surveys and are not used for purposes of calculating emissions. Therefore, we are proposing in 40 CFR 98.233(q)(1)(vi)(F) that onshore natural gas processing facilities subject to NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62 would use the data derived from each equipment leak survey conducted as required by NSPS OOOOb or the relevant subpart of 40 CFR part 62 along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report GHG emissions to the GHGRP, even if a survey required for compliance with NSPS OOOOb or 40 CFR part 62 does

[100] We are similarly proposing to revise the existing reporting requirement in subpart W related to NSPS OOOOa, such that reporters would report whether any of the surveys of well sites or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOa (rather than simply reporting whether the facility has well sites or compressor stations subject to the fugitive emissions standards in NSPS OOOOa).

not include all the component types listed in 40 CFR 98.232(d)(7).

Under this proposed amendment, reporters would still have to meet the subpart W requirement to conduct at least one complete survey of all applicable equipment at the facility per year, so if there were components listed in 40 CFR 98.232(d)(7) not included in any NSPS OOOOb or 40 CFR part 62-required surveys conducted during the year (*e.g.*, connectors that are monitored only once every 4 years), reporters subject to NSPS OOOOb or 40 CFR part 62 would need to either add those components to one of their required surveys, making that a complete survey for purposes of subpart W, or conduct a separate complete survey for purposes of subpart W. We expect that reporters with onshore natural gas processing plants implementing traditional leak detection and repair programs are already making similar decisions regarding how to meet the requirement to conduct a complete survey for subpart W, and our intention with this proposed amendment is not to change those decisions. Rather, this amendment would specify that surveys conducted pursuant to NSPS OOOOb or 40 CFR part 62 that do not include all component types listed in 40 CFR 98.232(d)(7) would be used for calculating emissions along with each complete survey.

We are also proposing to add leaker emission factors for all survey methods for ''other'' components that would be required to be monitored under NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 or that reporters elect to survey that are not currently included in subpart W. These proposed THC leaker emission factors for the ''other'' component type are of the same value as the THC leaker emission factors for the ''other'' component type for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (existing Table W–3A and Table W–4A, respectively, proposed Table W–4). For more information on the derivation of the original emission factors, see the 2010 subpart W TSD,[101] and for more information on the derivation of the ''other'' component type emission factor proposed to be applied to these types of leaks at facilities in the Onshore Natural Gas Processing industry segment, see the TSD for the 2016 amendments to subpart W.[102] In a corresponding amendment, we are also proposing to expand the reporting requirement in existing 40 CFR 98.236(q)(1)(iii) (proposed 40 CFR 98.236(q)(1)(iv)) to require onshore natural gas processing reporters to indicate if any of the surveys used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the equipment leak standards in NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62. We request comment on the proposed amendments to subpart W for onshore natural gas processing facilities subject to the equipment leak provisions of NSPS OOOOb or 40 CFR part 62, as well as whether there are other provisions or reporting requirements for these facilities that we should consider.

Finally, in our review of subpart W equipment leak requirements for onshore natural gas processing facilities, we found that the leak definition for the Method 21-based requirements for processing plants in NSPS OOOOa (as well as proposed NSPS OOOOb and EG OOOOc presumptive standards) is not consistent with the leak definition in the Method 21 option in current 40 CFR 98.234(a)(2), which is the only Method 21-based method available to onshore natural gas processing facilities under subpart W. Based on this review, and to complement the proposed addition of default leaker emission factors for survey methods other than Method 21 (as described previously in this preamble), we are proposing several additions to the equipment leak survey requirements for the Onshore Natural Gas Processing industry segment, beyond those amendments already described related to the proposed NSPS OOOOb and EG OOOOc presumptive standards. First, we are proposing default leaker emission factors for Method 21 at a leak definition of 500 ppm in proposed Table W–4. As with the proposed ''other'' component type leaker emission factors, these proposed leaker emission factors (*i.e.*, valve, connector, open-ended line, pressure relief valve and meter) are of the same value as the THC leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (existing Table W–3A and Table W–4A, respectively). For more information on the derivation of those emission factors, see the TSD for the 2016 amendments to subpart W.[103] In addition, we are proposing to add 40 CFR 98.233(q)(1)(v) to indicate that onshore natural gas processing facilities not subject to NSPS OOOOb or an approved state plan or the applicable Federal plan in 40 CFR part 62 may use any method specified in 40 CFR 98.234(a), including Method 21 with a leak definition of 500 ppm and OGI following the provisions of appendix K to 40 CFR part 60. This proposed amendment would ensure that equipment leak surveys conducted using any of the approved methods in subpart W would be available for purposes of calculating emissions, not just those surveys conducted using one of the methods currently provided in 40 CFR 98.234(a)(1) through (5).

7. Exemption for Components in Vacuum Service

Through correspondence with the EPA via e-GGRT, some reporters have stated that certain equipment leak components at their facility are in vacuum service. These reporters indicated that there are no fugitive emissions expected from components in vacuum service. After consideration of these comments and in order to be consistent with other EPA equipment leak regulatory programs (*e.g.,* 40 CFR part 60, subpart VVa), we have determined that we agree with commenters. Therefore, we are proposing an exemption in the introductory paragraphs of 40 CFR 98.233(q) and (r) for leak components in vacuum service from the requirement to estimate and report emissions from these components. We are also proposing a definition in 40 CFR 98.238 for the term ''in vacuum service.'' We are proposing to require the reporting of the count of equipment in vacuum service to enable verification of the reported data (*i.e.*, ability to confirm that all equipment for which emissions are expected has been accounted for and an indication that other equipment has been confirmed to meet the proposed definition of ''in vacuum service'').

Q. Equipment Leaks by Population Count

As noted in section III.P of this preamble, subpart W reporters are currently required to quantify emissions from equipment leaks using the

[101] *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Systems Industry: Background Technical Support*. November 2010. Docket Id. No. EPA–HQ–OAR–2009–0923–3610; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[102] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*. November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[103] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*. November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count), depending upon the industry segment. The equipment leaks by population count method uses the count of equipment components, subpart W emission factors (*e.g.,* existing Table W–1A for the Onshore Petroleum and Natural Gas Production industry segment), and operating time to estimate emissions from equipment leaks. For the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the count of equipment components currently may be determined by counting each component individually for each facility (Component Count Method 2) or the count of equipment components may be estimated using the count of major equipment and subpart W default average component counts for major equipment (Component Count Method 1) in existing Tables W–1B and W–1C, as applicable. Reporters in other industry segments currently must count each applicable component at the facility. We are proposing several amendments to the calculation methodology provisions of 40 CFR 98.233(r) and the reporting requirements in 40 CFR 98.236(r) to improve the quality of the data collected, consistent with sections II.B and II.C of this preamble.

1. Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Population Count Method

The current population emission factors for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are found in existing Table W–1A of subpart W. The gas service population emission factors are based on the 1996 GRI/EPA study *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks* (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234). The oil service population emission factors are based on the American Petroleum Institute's (API) Emission Factors for Oil and Gas Production Operations, Publication 4615, published in 1995.

As noted previously in this section, when estimating emissions using the population count method, onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities currently have the option to use actual component counts (*i.e.,* Component Count Method 2) or to estimate their component counts using the count of major equipment (*e.g.,* wellhead) and default component counts per major equipment (*e.g.,* valves per wellhead) included in existing Tables W–1B and W–1C of subpart W (*i.e.,* Component Count Method 1). In reviewing subpart W data, we find that the vast majority (greater than 95 percent) of onshore production and natural gas gathering and boosting facilities use Component Count Method 1 to estimate the count of components.

It is important to note that both the population count emission factors and the default component counts per major equipment currently included in Tables W–1A, W–1B and W–1C are service-specific (*i.e.,* gas or oil) as well as region-specific (*i.e.,* eastern or western U.S.). The regional designations are provided by U.S. state in existing Table W–1D of subpart W such that a facility would determine the facility's region and select the appropriate region- and service-specific factors.

In the years that have followed the adoption of these emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks at onshore production and gathering and boosting facilities. Two recent field studies, Pacsi *et al.* (2019)[104] and Zimmerle *et al.* (2020),[105] have performed an equipment and component inventory alongside equipment leak screening and measurement results. Another recent study, Rutherford *et al.* (2021),[106] included synthesis and analysis of measurements from component-level field studies. These studies' data allow development of study-estimated population emission factors as well as study-estimated default component counts per major equipment and comparison of them to those in subpart W. Comparison of the study-estimated default component counts per major equipment found that the subpart W values underestimate the count of components found on major equipment in the field (Zimmerle *et al.*, 2020; Pacsi *et al.*, 2019). Regarding a comparison of the population emission factors and component counts per major equipment between the subpart W eastern and western values, Zimmerle *et al.* (2020) was the only field study to include both eastern and western facilities, and the study values showed ''no statistically significant differences between eastern and western U.S. regions.'' Rutherford *et al.* (2021) also found their study-estimated population emission factors to be higher than those in subpart W, noting that one of the contributing factors to this difference was the use of the eastern factors in subpart W, which appear to significantly undercount emissions. Rutherford *et al.* (2021) noted that the impact of the use of the eastern factors has grown over time as the production in the eastern region of the U.S. has increased from less than 5 percent of gas produced to nearly 30 percent of the gas produced.

In the 2022 Proposed Rule, we proposed to revise the current population emission factors to use major equipment-based emission factors developed using a combination of data from Zimmerle *et al.*, 2020 and Pacsi *et al.*, 2019. As described in more detail below, consistent with the 2022 Proposed Rule, we are again proposing revised emission factors on a per major equipment basis rather than on a per component basis. However, in this proposed rulemaking, we are proposing to use the data from Rutherford *et al.* (2021), which is comprised of several published studies including Pacsi *et al.* 2019, to inform the emission factor values. As described in more detail below, the Rutherford *et al.* (2021) study represents the largest dataset set available and thus, more accurately accounts for the variability observed in equipment leak measurement data in terms of the size and frequency of leaks.

Based on our review of these studies, our assessment is that they support revision of the population count method and corresponding emission factors for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities and we are proposing to amend this population count method and corresponding emission factors after consideration of these more recent study data, consistent with section II.B of this preamble. These proposed amendments include new population emission factors that are on a per major equipment basis rather than a per component basis. As mentioned previously, the vast majority of reporters estimate the component counts using

[104] Pacsi, A.P. *et al.* Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elementa (2019). *https://doi.org/10.1525/elementa.368.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[105] Zimmerle, D., *et al. Methane Emissions from Gathering Compressor Stations in the U.S. Environmental Science & Technology 54* (12), 7552–7561 (2020). *https://doi.org/10.1021/acs.est.0c00516.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[106] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al. Closing the methane gap in US oil and natural gas production inventories.* Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

Component Count Method 1. By providing emission factors on a major equipment basis instead of by component, we would eliminate the step to estimate the number of components. All facilities would be able to count the actual number of major equipment and consistently apply the same emission factor to calculate emissions. This would reduce reporter burden and reduce the number of errors in the calculation of emissions, as we find that numerous facilities incorrectly estimate the number of components using Component Count Method 1 while providing consistently estimated emission results.

In comparing the recent study data for this proposal, our assessment is that the Rutherford *et al.* (2021) study represents the most robust sample size of approximately 3,700 measurements for developing population emission factors by major equipment. The larger sample size is likely more representative of varying degrees of leak detection and repair programs (*i.e.,* not only facilities conducting frequent surveys), which can impact the number of leaks found during surveys (*i.e.,* if more frequent surveys are being conducted and leaks are being repaired in a timely manner, then each survey likely finds less leaks). The Rutherford *et al.* (2021) study also employs a bootstrap resampling statistical approach [107] that allows for the inclusion of infrequent large emitters (*i.e.,* ''super-emitters'') in the development of the emission factors, improving the representation of the inherent variability of equipment leaks in the developed emission factors. Therefore, we are proposing major equipment emission factors developed using Rutherford *et al.* (2021) to provide population emission factors by major equipment and site type (*i.e.,* natural gas system or petroleum system). The proposed emission factors were taken from Supplementary Tables 3 and 4 of Rutherford *et al.* (2021). The average emission factors presented in these study tables were converted from units of kilograms per day to standard cubic feet of whole gas per hour for cumulative equipment component leaks from different types of major equipment including wellheads, separator, heater, meter including headers, compressor, dehydrator and tanks. The major equipment indicating venting emissions (*e.g.,* tanks—unintentional vents) or emissions from other sources also covered by subpart W (*e.g.,* liquids unloading, flaring, pumps) are not included in the proposed equipment leak population emission factors. Specific to meters/piping and consistent with current requirements related to meters/piping at existing 40 CFR 98.233(r)(2)(i)(A), we are proposing in 40 CFR 98.233(r)(2) to specify that one meters/piping equipment should be included per well-pad for onshore petroleum and natural gas production operations and the count of meters in the facility should be used for this equipment category at onshore petroleum and natural gas gathering and boosting facilities. As a consequence of the broader scope of equipment surveyed in the study data that inform Rutherford *et al.* (2021), the proposed emission factors in proposed Table W–1 include more pieces of major equipment than are currently included in Table W–1B and W–1C of subpart W. A complete description of the derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. The proposed major equipment emission factors would replace the current component-based emission factors in the existing Table W–1A. We are also proposing to remove Tables W–1B, W–1C, and W–1D since they would no longer be needed for the population count method for these industry segments. We are proposing amendments to the reporting requirements for the use of the population count method to align with the reporting of major equipment counts consistent with the proposed emission factors in 40 CFR 98.236(r). We are seeking comment on the development of population count emission factors based on major equipment. We are also seeking comment on the proposed use of the Rutherford *et al.* (2021) study data instead of using study data from Zimmerle *et al.* (2020) and/or Pacsi *et al.* (2019) to provide the population count emission factors by major equipment, and the rationale supporting the use of the respective study data.

2. Natural Gas Distribution Emission Factors

Natural gas distribution companies currently quantify the emissions from equipment leaks from pipeline mains and services, below grade transmission distribution transfer stations, and below grade metering-regulating stations following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in existing Table W–7 (proposed Table W–5 in this proposal), and operating time to estimate emissions. The population emission factors for distribution mains and services in existing Table W–7 (proposed Table W–5) are based on information from the 1996 GRI/EPA study.[108] Specifically for plastic mains, additional data are sourced from a 2005 ICF analysis.[109] The population emission factors for distribution mains are published per mile of main by pipeline material and emission factors for distribution services are published per service by pipeline material. The population emission factors for below grade stations in existing Table W–7 (proposed Table W–5) are based on information from the 1996 GRI/EPA study.[110] The population emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations are currently specified in the existing Table W–7 per station by three inlet pressure categories (≤300 pounds per square inch gauge (psig), 100–300 psig, < 100 psig).

In this rulemaking, the EPA is proposing to update the population emission factors in existing Table W–7 (proposed Table W–5) to subpart W using the results of studies and information that were not available when the rule was finalized in 2010. Notably, the EPA reviewed recent studies and updated the emission factors for several natural gas distribution sources, including pipeline mains and services and below grade stations, for the 2016 U.S. GHG Inventory.[111] The majority of the U.S. GHG Inventory updates were based on

[107] Bootstrapping is a type of resampling where a known dataset is repeatedly drawn from, with replacement, to generate a sample distribution.

[108] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[109] ICF. *Fugitive Emissions from Plastic Pipe,* Memorandum from H. Mallya and Z. Schaffer, ICF Consulting to L. Hanle and E. Scheehle, EPA. June 30, 2005. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[110] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell and B.E. Stapper, Radian International LLC. GRI–94/0257.27, EPA–600/R–96–080j. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[111] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014: Revisions to Natural Gas Distribution Emissions.* April 2016. Available at *https://www.epa.gov/sites/production/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

data published by Lamb *et al.* in 2015.[112] Since the time that the 2016 U.S. GHG Inventory updates were made, additional studies for pipeline distribution mains have been published and reviewed by the EPA, notably Weller *et al.* in 2020.[113] Our assessment of the studies published since subpart W was finalized supports revising the emission factors for pipelines in the Natural Gas Distribution industry segment of subpart W.

The population emission factors for distribution mains and services are a function of the average measured leak rate (in standard cubic feet per hour) and the frequency of annual leaks observed (leaks/mile-year or leaks/service-year) by pipeline material (*e.g.,* protected steel, plastic). The Lamb *et al.* and Weller *et al.* studies utilized different approaches for quantifying leak rates and determining the pipeline material-specific frequency of annual leaks. The Lamb *et al.* study quantified leaks from distribution mains and services using a high volume sampling method and some downwind tracer measurements and estimated the frequency of leaks by pipeline material using company records and Department of Transportation (DOT) repaired leak records from six local distribution companies (LDCs). This methodology was consistent with the 1996 GRI/EPA study. The Weller *et al.* study quantified leaks from only distribution mains using the AMLD technique, which involves mobile surveying using high sensitivity instruments and algorithms that predict the leak location and size, attributed leaks to the pipeline material using geographic information system (GIS) data, and estimated the frequency of leaks using modeling.

In the 2022 Proposed Rule, we proposed to revise the pipeline main equipment leak emission factors using a combination of data from Lamb *et al.* (2015) and Weller *et al.* (2020). We sought comment on the approach of combining data from these two studies. We received numerous comments regarding the classification of pipeline materials and respective quantified leaks in the Weller *et al.* (2020) study. In response to these comments and as discussed in more detail below, we agree with commenters that the categorization of pipeline leaks by material type likely resulted in inaccuracies specifically for the unprotected and protected steel pipeline material types. In this rulemaking, we are continuing to propose revisions of the equipment leak pipeline main emission factors using more recent study data, but instead of combining data from Lamb *et al.* (2015) and Weller *et al.* (2020), we are proposing to rely only on the Lamb *et al.* (2015) study.

In subpart W, there are currently four categories of pipeline mains: unprotected steel, protected steel, plastic, and cast iron. The steel categories are differentiated by the presence of cathodic protection, and, as evidenced by the 1996 GRI/EPA study and Lamb *et al.* study data, unprotected steel pipelines are considered to be more leak prone than cathodically protected steel pipelines. In the Weller *et al.* study, the categories of pipeline mains include bare (unprotected) steel, coated (protected) steel, cast iron, and plastic. We note that steel pipelines can be protected by cathodic protection and/or coating, and in the Weller *et al.* study, cathodically unprotected yet coated steel pipeline mains appear to have been grouped with cathodically protected steel pipeline mains. Using the unprotected and protected steel classifications in the Weller *et al.* study would thus result in emission factors for protected steel that are higher than for unprotected steel, which would conflict with other study data (*e.g.,* 1996 GRI/EPA, Lamb *et al.*) as well as voluntary emissions reductions programs (*e.g.,* EPA Natural Gas STAR). The pipeline categories in the Weller *et al.* study do not provide the necessary differentiation to properly update the emission factors for unprotected (*i.e.,* not cathodically protected) steel and cathodically protected steel pipeline mains. For more information on the review and analysis of the Lamb *et al.* and Weller *et al.* studies, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

In consideration of our review and analysis of recent study data relative to natural gas pipeline mains and services, and consistent with the emission factors used in the 2016 U.S. GHG Inventory, we are proposing to provide emission factors for distribution pipeline mains and services based on the Lamb *et al.* study leak rates and the 1996 GRI/EPA study leak incidence data. For more information on the derivation of the proposed emission factors, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

We are also seeking comments on alternative methods for quantifying and reporting emissions from distribution mains and services. For distribution mains and services, we are seeking comments on the use of direct measurement as well as application of a leaker emission factor approach. For the use of direct measurement, we are seeking comment on whether facilities should be permitted to develop facility-specific distribution main and service emission factors for each type of pipeline material based on direct measurements and if so, what the appropriate number of measurements should be for determining a representative emission factor for each pipeline material including supporting rationale. For facility-specific emission factors based on direct measurement, we are seeking comment on the development of both leaker emission factors and population emission factors. We are seeking comment on what quantification techniques are best suited for measuring emissions from distribution pipeline leaks and whether these techniques require digging down to the pipeline in order to quantify emissions and also verify pipeline characteristics. For a leaker emission factor approach, we are specifically interested in what survey techniques are appropriate and why, including supporting information on specific instruments and their detection capabilities and whether certain methods are more suitable for the survey of distribution pipeline leaks than others. We are seeking comment on the scope and frequency of leak detection surveys for distribution pipelines and whether annual surveys of the entire pipeline system or a reduced frequency of survey (*i.e.,* partial surveys over a multi-year survey cycle in which the entire system is surveyed during the survey cycle and approximately equal portions of the system are surveyed each year of the multi-year survey cycle) is more appropriate and why. Finally, we are seeking comment on application of a leaker emission factor approach using default factors (*i.e.,* not facility specific based on direct measurement) and available data that could be used in the development of default leaker emission factors for distribution mains and services.

For below grade stations, the 2016 U.S. GHG Inventory also began applying a new emission factor from the data published by Lamb *et al.* to the count of stations to estimate emissions from these sources. In order to assess the

[112] Lamb, B.K. *et al.* ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[113] Weller, Z.D.; Hamburg, S.P.; and Von Fischer, J.C. 2020. ''A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems.'' *Environ. Sci. Technol.* 2020, *54*(1), 8958. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

appropriateness of incorporating this revision into the subpart W requirements for below grade stations (*i.e.,* replacing the set of below grade emission factors by station type and inlet pressure with one single emission factor), the EPA performed an analysis of the reported subpart W data for below grade stations compared to data from the recent studies (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234). We found that the subpart W reported station count combined with the current subpart W emission factors yields an average emission factor similar to the U.S. GHG Inventory emission factor; as such, using either set of emission factors would yield approximately the same emissions results for the GHGRP.

Therefore, we are proposing to amend the emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations in existing Table W–7 (proposed Table W–5) to a single emission factor without regard to inlet pressure. We are also proposing to amend the corresponding section header in existing Table W–7 (proposed Table W–5) for below grade station emission factors and the references to existing Table W–7 (proposed Table W–5) in 40 CFR 98.233(r)(6)(i) to clarify the emission factor that should be applied to both types of below grade stations (*i.e.,* transmission-distribution transfer and metering-regulating). This proposed amendment would impact the reporting requirements in 40 CFR 98.236(r) as well, as it would consolidate six emission source types to two emission source types (below grade transmission-distribution transfer stations and below grade metering-regulating stations, without differentiating between inlet pressures) for purposes of reporting under 40 CFR 98.236(r)(1). This proposed amendment would improve the data quality through use of more recent emission factors and would be consistent with changes made to the U.S. GHG Inventory. It would also result in reporting of fewer data elements, consistent with section II.C of this preamble.

3. Gathering Pipeline Emission Factors

Facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment currently quantify the emissions from equipment leaks from gathering pipelines following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in existing Table W–1A, and operating time to estimate emissions. The population emission factors for gathering pipeline mains in existing Table W–1A are based on leak rates from natural gas distribution companies and gathering pipeline-specific activity data as provided in the 1996 GRI/EPA study.[114] The population emission factors for gathering pipelines are published per mile by pipeline material.

The EPA is aware of a recent study that characterized emissions from gathering pipelines and could potentially be used to develop population emission factors, Yu *et al.* (2022).[115] The Yu *et al.* (2022) study used measurements acquired over four aerial campaigns of the Midland and Delaware sub-basins in the Permian basin. The resulting emission rate provides a basin-level population emission factor (megagrams CH_4 per kilometer-year). The EPA is not proposing to use this data in subpart W for the development of gathering pipeline emission factors because it does not specify the pipeline material type, as the current subpart W and proposed subpart W emission factors do. The material-specific emission factors more readily allow operators to track and quantify emission reductions from pipeline replacement projects (*e.g.,* replacing more leak prone pipeline materials such as cast iron with less leak prone materials such as plastic). The resulting emission factors from Yu *et al.* rely on emission estimation techniques that have a lower degree of sensitivity than ground-based measurements. In order to overcome this limitation, the study authors performed sensitivity analyses to account for below detection limit leaks. The major finding of this study is that gathering pipelines have highly skewed emissions data distribution with very large leaks that only occur every few hundred miles. Finally, our assessment is that this study is geographically limited and are concerned that an emission factor derived with these study data may not be nationally representative. Additional discussion of the Yu *et al.* study, including population emission factors developed using study data as they compare to subpart W, is included in the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. v). We are seeking comment on the EPA's decision not to use the Yu *et al.* study data in developing proposed population emission factors, including rationale supporting the EPA's decision or rationale for why this study should be used in developing proposed population emission factors. Additionally, we are seeking comments on whether there are other published studies the EPA should evaluate for potential use in developing revised emission factors for gathering pipelines.

As noted previously in this section, the EPA is proposing to update the natural gas distribution population emission factors in existing Table W–7 (proposed Table W–5) to subpart W using the results of studies and information that were not available when the rule was originally finalized. In particular, the EPA is proposing to update the leak rate portion of the emission factor based on data published by Lamb *et al.* in 2015.[116]

The EPA has reviewed the recent studies published for Onshore petroleum and natural gas gathering and boosting facilities including the previously discussed Yu *et al.* study, as well as the additional studies for pipeline distribution mains, and concluded none of the studies provide new emissions data or activity data specific to gathering pipelines suitable to update the existing emission factors. Therefore, consistent with the updates to the emission factors for distribution mains, and consistent with section II.B of this preamble, we are proposing to revise the gathering pipeline population emission factors in proposed Table W–1 to use the leak rates from Lamb *et al.* (2015). We are not proposing to update the activity data (leaks per mile of pipeline) portion of the emission factors, as the information in the 1996 GRI/EPA study continues to be the best available data specific to gathering pipelines. For more information on the proposed updates to the gathering pipeline population emission factors, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

We are also seeking comments on alternative methods for quantifying and reporting emissions from gathering pipelines. We are seeking comments on the use of direct measurement as well as

[114] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[115] Yu, J. et al. ''Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin.'' *Environ. Sci. Technol. Lett.* 2022, 9, 969–974. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[116] Lamb, B.K. *et al.* ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

application of a leaker emission factor approach. For the use of direct measurement, we are seeking comment on whether facilities should be permitted to develop facility-specific emission factors for each type of pipeline material based on direct measurements and if so, what the appropriate number of measurements should be for determining a representative emission factor for each pipeline material including supporting rationale. For facility-specific emission factors based on direct measurement, we are seeking comment on the development of both leaker emission factors and population emission factors. We are seeking comment on what quantification techniques are best suited for measuring emissions from gathering pipeline leaks and whether these techniques require digging down to the pipeline in order to quantify emissions and also verify pipeline characteristics. For a leaker emission factor approach, we are specifically interested in what survey techniques are appropriate and why, including supporting information on specific instruments and their detection capabilities and whether certain methods are more suitable for the survey of gathering pipeline leaks than others. We are seeking comment on the scope and frequency of leak detection surveys for gathering pipelines and whether annual surveys of the entire pipeline system or a reduced frequency of survey (*i.e.,* partial surveys over a multi-year survey cycle in which the entire system is surveyed during the survey cycle and approximately equal portions of the system are surveyed each year of the multi-year survey cycle) is more appropriate and why. Finally, we are seeking comment on application of a leaker emission factor approach using default factors (*i.e.,* not facility specific based on direct measurement) and available data that could be used in the development of default leaker emission factors for gathering pipelines.

R. Offshore Production

Currently, subpart W requires offshore production facilities to report emissions consistent with the methods published by the U.S. Department of Interior, Bureau of Ocean Energy Management (BOEM). Since subpart W was first promulgated, there have been a number of updates to the BOEM requirements and how BOEM implements the requirements (*e.g.,* the development of their Outer Continental Shelf Air Quality System (OCS AQS)[117]), and the EPA is proposing to amend subpart W to reflect those changes. Specifically, the EPA is proposing to update outdated acronym ''BOEMRE'' to the current acronym ''BOEM'' in 40 CFR 98.232(b), 40 CFR 98.233(s), and 40 CFR 98.236(s); to update the cross references to the BOEM requirements from ''30 CFR 250.302 through 304'' to ''30 CFR 550.302 through 304'' in 40 CFR 98.232(b), 40 CFR 98.233(s), and the introductory paragraph of 40 CFR 98.234; and to remove the outdated references to ''GOADS'' from 40 CFR 98.233(s). The EPA is also proposing to adjust some of the language in 40 CFR 98.232(b) and 40 CFR 98.233(s) to more accurately reflect the current BOEM program and requirements (*e.g.,* adjusting the number of years between BOEM data collection efforts from 4 to 3 years, referring to published data and data submitted to BOEM rather than an emissions study).

Emissions data are collected by BOEM every few years. In years that coincide with a year in which BOEM collects data, offshore production facilities that report emissions inventory data to BOEM report the same annual emissions to subpart W as calculated and reported to BOEM (existing 40 CFR 98.233(s)(1)) and facilities that do not report emissions inventory data to BOEM must use the most recent monitoring and calculation methods published by BOEM (existing 40 CFR 98.233(s)(2)). In the intervening years, reporters currently are required to adjust emissions based on the operating time for the facility in the current reporting year relative to the operating time in the most recent BOEM data submission or BOEM emissions study publication year. The EPA is proposing two revisions for these intervening years. First the EPA is proposing to require reporters to report two new data elements in these years, the facility's operating hours in the current year and the facility's operating hours from the BOEM emission study publication year that is the basis for the reported emissions. This information would improve verification, consistent with section II.C of this preamble. Second, as an alternative to the current adjustment using operating hours in years that do not overlap with the most recent BOEM data submission or BOEM emissions study publication year, as applicable, the EPA is also proposing to allow reporters to calculate emissions using the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 (implemented through the OCS AQS). This alternative is expected to improve data quality through the use of more empirical data, consistent with section II.B of this preamble.

Finally, to better align the emissions reported by offshore production facilities between BOEM's Outer Continental Shelf Emissions Inventory and the GHGRP, the EPA is proposing that offshore production facilities report the BOEM Facility IDs that constitute the GHGRP facility. Having a definitive point of reference between the two datasets would allow the EPA to better verify the emissions reported to the GHGRP.

S. Combustion Equipment

1. Clarifications of Calculation Methodology Applicability

All facilities reporting under subpart W except those in the Onshore Natural Gas Transmission Pipeline industry segment must include combustion emissions in their annual report. Facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments calculate emissions in accordance with the provisions in 40 CFR 98.233(z) and report combustion emissions per 40 CFR 98.236(z). Reporters in the other industry segments calculate and report combustion emissions under subpart C (General Stationary Fuel Combustion Sources). Subpart W refers reporters in these segments to the calculation methodologies in subpart C to determine combustion emissions for certain fuels. Specifically, 40 CFR 98.233(z)(1) specifies that reporters may use any tier of subpart C if the fuel combusted is listed in Table C–1; the paragraph further specifies that the subpart C methodologies may only be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it is also of pipeline quality specification and has a minimum HHV of 950 British thermal units per standard cubic foot (Btu/scf). If the fuel is natural gas that does not meet these criteria, field gas, process vent gas, or a blend containing field gas or process vent gas, 40 CFR 98.233(z)(1) specifies that the procedures in 40 CFR 98.233(z)(2) should be used to calculate combustion emissions.

Certain stakeholders have identified several concerns with these requirements. In general, these stakeholders have stated that the ability to use subpart C calculation methodologies is too restrictive, and some of their feedback also indicates

[117] For more information on this system and the emissions inventories collected by the system, see *https://www.boem.gov/environment/environmental-studies/ocs-emissions-inventories.*

they may have been misinterpreting some of the provisions. We are proposing several amendments to these provisions to address these concerns, which would improve the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.B of this preamble.

First, a stakeholder indicated that some member companies have been interpreting the existing provisions of 40 CFR 98.233(z)(1)(ii) that require emissions to be reported according to 40 CFR 98.236(z) and not subpart C to mean that reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must use the calculation methodologies in subpart W for all fuel types rather than subpart C (even given the provisions in 40 CFR 98.233(z)(1) that reference subpart C for certain fuels).[118] The existing provisions of 40 CFR 98.233(z)(1)(ii) are intended to refer only to the reporting requirements and are not intended to define which calculation methodologies can be used. In the existing rule, the provisions in the 40 CFR 98.233(z)(1) introductory text define which calculation methodologies can be used, and 40 CFR 98.233(z)(1)(ii) simply indicates that all reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must report those emissions in the e-GGRT system under subpart W rather than under subpart C. As part of the amendments described in this section, consistent with section II.D of this preamble, 40 CFR 98.233(z)(1)(ii) is proposed to be moved to 40 CFR 98.233(z)(5), and we are proposing wording changes to highlight that this paragraph refers only to the requirement to report combustion emissions under subpart W and does not preclude reporters from using subpart C methods to calculate emissions if they qualify to do so under proposed 40 CFR 98.233(z)(1) (and proposed 40 CFR 98.233(z)(2), as described later in this section. We are also proposing to add a reference to this new proposed paragraph 40 CFR 98.233(z)(5) in both proposed 40 CFR 98.233(z)(1)(ii) and proposed 98.233(z)(2)(ii).

Second, a stakeholder has asked for EPA guidance regarding whether field gas that is of pipeline quality meets the criteria to use the subpart C methodologies under the existing 40 CFR 98.233(z)(1),[119] and the stakeholder noted that ''field gas'' is not defined within existing subpart W or subpart A (General Provisions). The terms ''field gas'' and ''field quality'' are frequently used interchangeably by the industry, but the EPA also recognizes that some streams in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment that industry would generally call ''field gas'' can be natural gas (as defined in 40 CFR 98.238) of pipeline quality with a minimum HHV of 950 Btu/scf. After consideration of these concerns, the EPA is proposing to revise 40 CFR 98.233(z)(1) to remove the references to field gas and process vent gas and include only the characteristics for the fuels that can use subpart C methodologies. The EPA's intent is to indicate that a stream colloquially referred to as ''field gas'' that otherwise meets the three criteria to use the subpart C methodologies for combustion emissions (i.e., (1) meets the definition of ''natural gas'' in 40 CFR 98.238; (2) is of pipeline quality specification; and (3) has a minimum HHV of 950 Btu/scf) may use subpart C methodologies. The EPA is also proposing conforming edits to existing 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3) in this proposed rule) for consistency.

Third, certain reporters have indicated in questions submitted to the GHGRP Help Desk that the term ''pipeline quality'' is used in existing 40 CFR 98.233(z)(1) but it is not defined in subpart W. In addition, a stakeholder has opined that the emissions calculated using subpart C and subpart W calculation methodologies are similar for many fuel streams that are not natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf. Therefore, the stakeholder suggested that the EPA should allow subpart C calculation methodologies to be used for a wider variety of fuels (if not all fuels in the segments that report combustion emissions under subpart W).[120]

We have reviewed this stakeholder's analysis and conducted our own analysis of additional hypothetical fuel compositions. In general, we observed that the agreement of emissions as calculated using subpart C calculation methodologies for natural gas and using subpart W calculation methodologies varies based on the composition, with the largest differences resulting for fuel streams with high CO_2 content. We also observed that for these fuels, emissions calculated using subpart W calculation methodologies generally showed better agreement with emissions calculated using the subpart C calculation methodology for natural gas when using a site-specific HHV (Tier 2) than with emissions calculated using the subpart C calculation methodology that uses a default HHV (Tier 1). For more information on our fuel composition analysis and the comparison of emissions using various composition thresholds, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

Based on our analysis, we are proposing to add numeric composition thresholds for natural gas to a new proposed paragraph in 40 CFR 98.233(z)(2) that define the fuels for which an owner or operator may use subpart C methodologies. In particular, we are proposing that subpart C methodologies Tier 2 or higher may be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum CO_2 content of 1 percent by volume, and a minimum CH4 content of 85 percent by volume. We are not proposing to amend the existing provisions in 40 CFR 98.233(z)(1) that allow the use of any subpart C calculation methodology for natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf (other than the proposed clarifications noted earlier in this section). We are also proposing to move the existing provisions for fuels that do not meet the specifications to use subpart C methodologies from 40 CFR 98.233(z)(2) to a new proposed paragraph 40 CFR 98.233(z)(3). This proposed amendment would allow reporters to use subpart C methodologies for a wider variety of fuel streams while still ensuring data quality. We request comment on the natural gas specifications included in proposed 40 CFR 98.233(z)(2), including the values proposed for the maximum

[118] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[119] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[120] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

CO_2 content and minimum CH_4 content, as well as whether additional specification criteria should be included (e.g., a maximum HHV).

2. Methane Slip from Internal Combustion Equipment

The authors of several recent studies have examined combustion emissions at Onshore Petroleum and Natural Gas Gathering and Boosting facilities and have demonstrated that a significant portion of emissions can result from unburned CH_4 entrained in the exhaust of natural gas compressor engines (also referred to as ''combustion slip'' or ''methane slip''). These studies contend that emissions from natural gas compressor engines included in the GHGRP are significantly underestimated because they do not account for combustion slip.[121] The EPA performed a review of each of these studies and the U.S. GHG Inventory to determine whether and how combustion slip emissions have been incorporated into published data and how the incorporation of combustion slip would affect the emissions from the petroleum and natural gas system sector reported to the GHGRP (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234).

In the 2022 Proposed Rule, we proposed methods to quantify and report combustion slip in subpart C and subpart W from compressor drivers for all subpart W industry segments that currently report combustion emissions in subpart C or subpart W. The emission estimation methods provided in the 2022 Proposed Rule were the use of default emission factors or default combustion efficiencies for compressor drivers based on recent study data. We received comments on the 2022 Proposed Rule requesting methods to quantify combustion slip using original equipment manufacturer (OEM) data and direct measurement. We also received comments that while compressor drivers likely represent the largest number of reciprocating engines in service at petroleum and natural gas facilities, there are reciprocating engines that do not drive compressors and other engine types (*e.g.,* GT) that emit CH_4 from combustion slip. We have performed additional review of the combustion slip emission source type as detailed below. In this rulemaking, we are continuing to propose the quantification and reporting of combustion slip from subpart W facilities that currently report combustion emissions in subpart C or subpart W. However, in consideration of the comments received on the 2022 Proposed Rule and the directives under CAA 136(h), we are broadening the applicability of the combustion slip quantification and reporting methods to all RICE and GT and additionally providing three methods for quantifying slip including default emission factors or combustion efficiencies, OEM data, or direct measurement. We are also proposing some revisions to the 2022 Proposed Rule for the reporting of combustion emissions for RICE and GT for subpart W facilities that report their combustion emissions to subpart C after performing a more detailed review of the subpart C e-GGRT combined unit reporting configurations.

Based on the EPA's review and analysis, there appears to be combustion slip for RICE and GT, which are used primarily to drive compressors, at oil and gas facilities. In addition, while the recent studies are focused on the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, the EPA's literature review found the presence of combustion slip in different industry segments, so it appears that combustion slip is dependent on the type of internal combustion equipment and not the application (*i.e.,* we expect combustion slip from RICE or GT regardless of the industry segment). We also considered that other EPA programs such as AP–42: Compilation of Air Pollutant Emissions Factors; 40 CFR part 60, subpart JJJJ; and 40 CFR part 63, subpart ZZZZ consider emissions from internal combustion equipment (*i.e.*, RICE or GT) irrespective of their use to drive a compressor or the industry segment in which the engine operates.

Therefore, consistent with section II.A of this preamble, we are proposing to revise the methodologies for determining combustion emissions from RICE and GT, including those that drive compressors, to account for combustion slip. For the three subpart W industry segments reporting combustion emissions to subpart W (Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution), we are proposing that RICE and GT combusting natural gas that qualify to determine emissions using the subpart C calculation methodologies per 40 CFR 98.233(z)(1) and proposed new 98.233(z)(2),[122] would have three options in proposed 40 CFR 98.233(z)(4) to quantify emissions from combustion slip, including direct measurement using a performance test, the use of OEM data, or the use of default emission factors. For facilities that conduct a performance test to calculate combustion slip, we are proposing in 40 CFR 98.233(z)(4)(i) that the performance test would be required one time, in accordance with one of the test methods in proposed 40 CFR 98.234(i), which include EPA Methods 18 and 320 as well as an alternate method, ASTM D6348–12. If a facility is required to or elects to conduct a performance test for any reason, we are proposing that they must use the results of the test for estimating emissions. The results of the performance test would be used to develop an emission factor for use in the emissions calculations for CH_4. For facilities electing to use OEM data, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the RICE or GT, we are proposing that the reporter would use the OEM data to develop an emission factor for use in their emissions calculations for CH_4. Concerning OEM data, we are seeking comment on whether OEM data is expected to be representative of field conditions. Further, we are considering proposing requirements for the OEM supplied data including defining a standardized testing program for engine families similar to those that underly the emissions certification process for the engine NSPS in 40 CFR part 60 subparts IIII and JJJJ (*e.g.,* Parts 1054 and 1065). These programs define the number of engines in a family that are required to be tested as a number (*e.g.,* 30) or a percentage of engines produced in a year. The programs also define the methods for testing the engines (including engine load, test duration, etc.) as well as deterioration factors for adjusting for the degradation of performance that is expected over time. Alternatively, we are considering that manufacturers perform the same type of testing incorporated in proposed 40 CFR 98.234(i) for a certain number of engines in an engine family. We are seeking comments on these considerations including how the manufacturer testing program should be structured and more specifically: how many engines should be tested in an engine family; under

[121] Zimmerle *et al., Characterization of Methane Emissions from Gathering Compressor Stations: Final Report* (October 2019 Revision) and Vaughn *et al.*, ''Methane Exhaust Measurements at Gathering Compressor Stations in the United States,'' *Environmental Science & Technology*. 2021, 55 (2), 1190–1196, both available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[122] See section III.S.1 of this preamble for information on the proposed amendments to 40 CFR 98.233(z) to increase the flexibility for reporters to use the subpart C calculation methodologies.

what load(s) should the engines be tested; what testing methods should be used; what is the appropriate duration of the test; and whether a deterioration factor be included to account for degradation of performance over time. We are also considering whether to add reporting requirements for the results of performance tests conducted by manufacturers. Finally, for facilities electing to the use the default emission factors, which were developed using data from Zimmerle et al. (2019), we are proposing that the reporter would be required to select the appropriate emission factor by equipment type (*e.g.,* 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn, or GT) in proposed new Table W–7 rather than the emission factors in Table C–2 for use in their emissions calculations for CH_4. The precise derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

For the three subpart W industry segments reporting combustion emissions to subpart W (Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution), we are proposing a default equipment specific combustion efficiency (proposed to be provided in equations W–39A and W–39B) for RICE and GT that must be used to determine emissions using the subpart W calculation methodologies per existing 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3)). The default combustion efficiency would account for methane slip, and be combined with fuel composition to calculate emissions. We are not proposing to provide options for reporters to conduct performance tests or use OEM data for such RICE and GT. The fuel types covered by the methods in existing 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3)) are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions.

We expect that the records necessary to confirm the value for the development of an emission factor based on the results of a performance test or OEM data are already required to be maintained by the facility per 40 CFR 98.237; thus, no new recordkeeping provisions relative to the combustion slip amendments are being proposed. We are proposing to add new reporting requirements to 40 CFR 98.236(z)(2) specifically for internal combustion engines that combust natural gas that meets the criteria of proposed 40 CFR 98.233(z)(1) or (2) to specify the equipment type of reported internal combustion units, the method used to estimate the CH_4 emission factor, and the value of the emission factor to facilitate verification of the reported emissions. Under the existing reporting structure, facilities can group internal combustion engines by the unit type and the fuel type. The proposed amendments would require further disaggregation of the reporting of natural gas-fired internal combustion engine and GT CH_4 emissions as units grouped for reporting must share the same equipment type (*e.g.,* 4-stroke rich burn), fuel type, and method for determining the CH_4 emission factor, which will allow the EPA to adequately verify the data.

For the subpart W industry segments that estimate and report their combustion emissions to subpart C, we are proposing amendments in subpart C analogous to the proposed amendments described in this section for the three industry segments that estimate and report their combustion emissions to subpart W (*i.e.,* Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution). Specifically, the facilities that report their combustion emissions to subpart C and currently use either equation C–8, C–8a, C–8b, C–9, C–9a, or C–10 in 40 CFR 98.33(c), as it corresponds to the Tier methodology selected to estimate their CO_2 emissions, to estimate CH_4 emissions. These equations rely on the use of a default CH_4 emission factor from Table C–2 to estimate emissions. We are proposing to require that natural gas-fired RICE or GT located at these facilities would be required to use one of the options in proposed 40 CFR 98.233(z)(4) to estimate CH_4 emissions. Specifically, we are proposing to revise the ''EF'' term in each of the equations in 40 CFR 98.33(c) (*i.e.,* equations C–8, C–8a, C–8b, C–9a, C–9b, and C–10) to reference the options for developing a CH_4 emission factor in proposed 40 CFR 98.233(z)(4) for natural gas-fired RICE or GT. We are also proposing to add a footnote to Table C–2 that specifies that for reporters subject to subpart W, the default CH_4 emission factor in Table C–2 for natural gas may only be used for natural gas-fired combustion units that are not RICE or GT. Finally, we are proposing to amend 40 CFR 98.36(b), (c)(1), and (c)(3) specifically for RICE or GT at facilities that are subject to subpart W. These provisions currently provide the requirements for reporting by emission unit, by aggregation of units or by common pipe configurations. Under the proposed amendments, we are requiring reporters which report emissions in accordance with 40 CFR 98.36(b), (c)(1), or (c)(3) to provide the equipment type (*e.g.,* two stroke lean burn RICE), the method used to determine the CH_4 emission factor and the average value of the CH_4 emission factor. This proposed change would ensure that sufficient data in the overall aggregation of units or common pipe (*i.e.,* multiple units combusting natural gas) is reported such that we can perform review of the supplied emission factor data and perform verification on the corresponding emissions. Overall, these proposed amendments to the subpart C reporting requirements are analogous to and consistent with what is being required for RICE or GT for facilities that report combustion emissions to subpart W.

3. Higher Heating Value for Calculating N_2O

As noted previously, there are subpart W specific methods for quantifying combustion equipment emissions for facilities that report their combustion emissions to subpart W in existing 40 CFR 98.233(z)(2) (proposed (z)(3) in this proposed rule). For quantifying emissions from N_2O specifically, the existing rule specifies the use of equation W–40. This equation requires the fuel throughput, the HHV of the fuel, and the use of a default emission factor. For field gas or process vent gas, the variable definition for the HHV provides that either a site-specific or default value may be used. We are proposing, consistent with section II.B of this preamble, to amend the definition of the variable for the HHV to require the use of a site-specific value because we believe the site-specific value more accurately accounts for the more variable fuel compositions that exist in field or process gas. Our assessment is that the methods for calculating CO_2 and CH_4 in 40 CFR 98.233(z)(2)(ii) (proposed (z)(3)(ii) in this proposed rule) already require the use of site-specific values for the hydrocarbon streams going to the combustion unit; therefore, we expect that a site-specific HHV is known (or can be calculated using the compositional data) without incurring additional burden, while increasing the accuracy of the emissions estimate.

4. Other Calculation Methodology Clarifications Applicability

To determine the concentrations of hydrocarbon constituents in the flow of gas to the combustion unit, existing 40

CFR 98.233(z)(2)(ii) specifies that reporters must either use a continuous gas composition analyzer (if one is present) or the procedures specified in 40 CFR 98.233(u)(2). For onshore petroleum and natural gas gathering and boosting facilities, 40 CFR 98.233(u)(2) specifies use of the annual average gas composition based on the most recent available analysis of the gas received at the facility. However, one stakeholder has indicated that for fuels using the existing provisions of 40 CFR 98.233(z)(2) to calculate emissions, the requirements for determining the gas composition could result in inaccurate calculations of emissions for some facilities because onshore petroleum and natural gas gathering and boosting facilities do not necessarily use the gas received at their facility for combustion.[123] For example, if the gas received at the facility is not suitable for combustion, they may mix the gas with purchased natural gas. In that case, the annual average composition of gas received at the facility would not be representative of the gas sent to the combustion unit (as required by existing 40 CFR 98.233(z)(2)), which could result in inaccurate emissions. Therefore, the EPA is proposing to revise the language in 40 CFR 98.233(z)(2)(ii) (proposed 40 CFR 98.233(z)(3)(ii)(B) in this proposed rule) to allow the use of engineering estimates based on best available data to determine the concentration of gas hydrocarbon constituent in the flow of gas to the unit. This proposed amendment would allow reporters to use the best information available to determine the gas composition while maintaining the option for reporters to use 40 CFR 98.233(u)(2) if they do not have other stream-specific information. This proposed amendment is expected to improve the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.B of this preamble.

We are also proposing amendments to clarify that emissions may be calculated for groups of combustion units. The existing provisions of 40 CFR 98.233(z)(2) (proposed 40 CFR 98.233(z)(3)(ii)) could be interpreted to specify that emissions must be calculated for each individual combustion unit. However, because combustion emissions and activity data are reported as combined totals for each type of combustion device, fuel type, and method for determining the CH_4 emission factor (for RICE and GT), it is generally not necessary to calculate emissions for each individual unit before aggregating the total emissions. For example, if the volume of fuel combusted is determined at a single location upstream of several combustion units, emissions may be determined for that combined volume of fuel (*i.e.,* for that group of combustion units). In other words, it would not be necessary in this example case to apportion a volume of fuel to each unit, calculate emissions separately, and then combine them again. If the combustion units downstream of this shared measurement point are a mix of combustion device types, the emissions and the volume of fuel would still need to be apportioned between those combustion device types for reporting purposes; however, reporters may elect to perform that apportioning either before or after emissions are calculated, as appropriate, as long as the group of combustion units does not include any natural gas internal combustion equipment including RICE or GT. If any of the combustion units downstream of this shared measurement point are natural gas-driven internal combustion equipment including RICE or GT, the volumes of fuel for those units would have to be separated from the total before emissions are calculated to account for the differences in combustion efficiency, as described in section III.S.2 of this preamble. Some of the tiers in subpart C similarly allow for calculation of emissions by groups of units combusting the same fuel, so we are proposing to include analogous language to that in subpart C in 40 CFR 98.233(z)(1)(ii) and 40 CFR 98.233(z)(2)(ii) to provide for these clarifications in how to calculate.

5. Location of Reporting Requirements for Combustion Equipment

Section 136(h) of the CAA specifies the following concerning reporting: ''Not later than 2 years after the date of enactment of this section, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total CH_4 emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.'' As noted in this excerpt, the IRA directs the Administrator to ensure reporting under subpart W accurately reflects total CH_4 emissions from applicable facilities.

Apart from onshore natural gas transmission pipeline facilities, all facilities subject to subpart W must include combustion emissions in their annual report. As noted in section III.S.1 of this preamble, facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments must calculate combustion emissions in accordance with 40 CFR 98.233(z) and report emissions under subpart W. Facilities in the remaining industry segments (*i.e.,* Offshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment) are required to calculate combustion emissions in accordance with the provisions of 40 CFR 98.33 and report emissions under subpart C.

The EPA is seeking comment on amending subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under subpart W to more accurately reflect the total CH_4 emissions from such facilities within the emissions reported under subpart W. Using RY2021 data for combustion sources, we determined that requiring combustion emissions from all oil and gas operations to be reported to subpart W rather than subpart C would increase total subpart W CH_4 emissions by less than 1 percent. If the amendments to combustion slip discussed in section III.S.2 of this preamble are finalized, the reported CH_4 emissions from combustion are expected to increase, but we estimate the increase in total CH_4 emissions from combustion devices at facilities subject to subpart W would be less than 5 percent. Under this approach, we would consider continuing to allow all the industry segments that currently report combustion emissions under subpart C (*i.e.,* Offshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment) to use the same subpart C calculation methodologies as they

[123] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

currently use in order to minimize the burden on affected facilities. This amendment, however, would result in changes to their reporting structure, as subpart W does not currently contain the same methods to report via a common pipe for fuel streams or by aggregation of units as provided in subpart C. Instead, for subpart W, combustion emissions are aggregated by fuel type, combustion equipment type, and if finalized, by the method used for estimating combustion slip, when applicable. There are also exclusions for reporting combustion emissions in 40 CFR 98.233(z)(5) and (6), specifically for external combustion equipment with a rated heat capacity of less than 5 million British thermal units per hour (MMBtu/hr) and internal combustion equipment with a rated heat capacity of less than 1 MMBtu/hr. Under this approach, we expect that these exemptions would apply to the facilities newly subject to subpart W. Similarly, under this approach, we expect that the exemptions in subpart C would no longer apply to these facilities. The exemptions that we expect may impact facilities under this approach are the subpart C exclusions of reporting emissions from portable and emergency equipment in 40 CFR 98.30(a) and (b).

T. Leak Detection and Measurement Methods

1. Acoustic Leak Detection

For emission source types for which measurements are required, subpart W specifies the methods that may be used to make those measurements in 40 CFR 98.234(a). To improve the quality of the data when an acoustic leak detection device is used, consistent with section II.B of this preamble, we are proposing two revisions to the acoustic measurement requirements in 40 CFR 98.234(a)(5). First, for stethoscope type acoustic leak detection devices (*i.e.,* those designed to detect through-valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate), we are proposing that a leak is detected if an audible leak signal is observed or registered by the device. Second, we are proposing that if a leak is detected using a stethoscope type device, then that leak must be measured using one of the quantification methods specified in 40 CFR 98.234(b) through (d) and that leak measurement must be reported regardless of the volumetric flow rate measured. These proposed revisions would improve the accuracy of emissions reported for compressors and transmission tanks when an acoustic leak detection device is used.

2. High Volume Samplers

We are proposing two revisions to the high volume sampler methods to improve the quality of the data when high volume samplers are used for flow measurements, consistent with section II.B of this preamble. First, we are proposing to add detail to 40 CFR 98.234(d)(3) to clarify the calculation methods associated with high volume sampler measurements. Generally, high volume samplers measure CH_4 flow, not whole gas flow. However, the current calculation methods in 40 CFR 98.234(d)(3) treat the measurement as a whole gas measurement. Therefore, we are proposing to clarify the calculation methods needed if the high volume sampler outputs CH_4 flow in either a mass flow or volumetric flow basis. Specifically, we are proposing methods to determine natural gas (whole gas) flows based on measured CH_4 flows.

Second, we are proposing to add a paragraph at 40 CFR 98.234(d)(5) to clarify how to assess the capacity limits of a high volume sampler. Currently, 40 CFR 98.234(d) simply states to ''Use a high volume sampler to measure emissions within the capacity of the instrument''; there is no other information provided to clarify what ''within the capacity of the instrument'' means or how it is determined. We understand that there are different manufacturers, but most common high volume samplers report maximum sampling rates of 10 to 11 cubic feet per minute (cfm) and maximum CH_4 flow quantitation limits of 6 to 8 cfm. Based on our review of reported high volume sampler measurements, we found that 2 to 5 percent of high volume sampler measurements for all types of compressor sources (for both centrifugal and reciprocating compressors) are likely at or beyond the expected capacity limits of the high volume sampler instrument. Considering actual sampling rates, gas collection efficiencies near the sampling rates, and reported CH_4 quantitation limits relative to maximum sampling rates, we determined that whole gas flow rates exceeding 70 percent of the device's maximum rated sampling rate is an indication that the device will not accurately quantify the volumetric emissions, which we deem to exceed the capacity of the device. Therefore, we are proposing to specify that CH_4 flows above the manufacturer's CH_4 flow quantitation limit or total volumetric flows exceeding 70 percent of the manufacturer's maximum sampling rate indicate that the flow is beyond the capacity of the instrument and that flow meters or calibrated bags must be used to quantify the flow rate. For more information on our review, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

U. Industry Segment-Specific Throughput Quantity Reporting

1. Throughput Information for the Future Implementation of the Waste Emissions Charge

As noted in section I.E of this preamble, the waste emissions charge specifies segment-specific thresholds (Waste Emissions Threshold) for segments subject to the waste emissions charge. For the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments, the Waste Emissions Threshold is specified in CAA section 136(f)(1) as, ''(A) 0.20 percent of the natural gas sent to sale from such facility;'' or ''(B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale.'' For the Onshore Petroleum And Natural Gas Gathering And Boosting, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, LNG Storage, LNG Import and Export Equipment, and Onshore Natural Gas Transmission Pipeline industry segments, the Waste Emissions Threshold is defined in CAA section 136(f)(2) and (3) as a percentage of ''natural gas sent to sale from or through such facility,'' with the percentages specified varying by segment.

To align the subpart W reporting elements with text used in CAA section 136 and enable verification of throughput-related reporting elements, consistent with section II.C of this preamble, we are proposing a combination of new reporting elements and amendments to existing segment-specific throughput reporting requirements in 40 CFR 98.236(aa).

We are proposing to add the word ''natural'' in front of ''gas'' at each occurrence where it is used in the throughput reporting elements in subpart W that are being revised to align with CAA section 136. We note that the CAA section 136 text uses the term ''oil'' and we are clarifying in this preamble that for the purposes of subpart W the term ''oil'' has the same meaning as ''crude oil,'' which is used in the throughput reporting elements in subpart W and defined in subpart A of part 98.

We are also generally proposing revisions to ensure that the verbiage of ''sent to sales'' or ''through the facility'' is reflected in the reporting elements, as applicable. We are also proposing in 40 CFR 98.236(aa) that the quantities sent to sales or through the facility be measured, as it is reasonable to expect that the quantities of these products are closely tracked. We request comment on situations in which a reporter may not be measuring the quantity ''sent to sales'' or ''through the facility.''

Aside from these overarching proposed amendments, there are industry segment-specific proposed amendments for the Onshore Petroleum and Natural Gas Production, Offshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Processing industry segments as described in the remainder of this section.

a. Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production

For the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments, the current requirements for reporting throughputs of crude oil are combined with volumes of condensate. These volumes will need to be reported separately in order to align with the CAA section 136(f) oil threshold for production facilities, when applicable. Therefore, we are proposing the separation of these reporting elements into two distinct reporting elements in both 40 CFR 98.236(aa)(1)(i) and 98.236(aa)(2).

For consistency with CAA section 136, we are proposing to use the phrase ''sent to sale'' in 40 CFR 98.236(aa)(1)(i)(B) through (D), 40 CFR 98.236(aa)(1)(iii)(C) through (E), and 40 CFR 98.236(aa)(2)(i) through (vi) instead of ''for sale,'' the phrase used in the existing data elements. This proposed amendment is for consistency in language rather than any expected difference in the volumes to be reported or the interpretation of the terms, as the existing term was intended to have the same meaning. As described in section III.D of this preamble, we are also proposing additional throughput data elements to provide separate, well-level reporting of throughputs associated with wells in the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments that are permanently shut-in and plugged. These proposed data elements, if finalized, are anticipated to be useful in the future evaluation of the associated exemptions in CAA section 136(f)(7).

Specifically for the Offshore Petroleum and Natural Gas Production industry segment, the existing throughput requirements are for ''gas handled'' at the platform, which includes production volumes as well as volumes transferred via pipeline from another location. We note that the term ''gas handled'' is not used by other reporting programs to which offshore production facilities also report, such as the BOEM or the U.S. Energy Information Administration (EIA). We have also recently received a question through the GHGRP Help Desk asking about differences in throughput between the published BOEM data for the parameter, lease production reporting, and throughput volumes published in the subpart W data, so there are potentially differences in the ways reporters are interpretating and reporting the ''gas handled'' data element as compared to production volumes reported to other programs. In order to provide consistency with the language in CAA section 136 across both production industry segments and help the EPA implement CAA section 136, we are proposing to revise the reporting elements in 40 CFR 98.236(aa)(2) for the Offshore Petroleum and Natural Gas Production industry segment so they are analogous to those in Onshore Petroleum and Natural Gas Production. We are seeking comment on whether we should add the proposed throughputs as new data elements and continue to retain the existing reporting elements in 40 CFR 98.236(aa)(2)(i) and (ii), including the rationale for maintaining the existing reporting elements.

b. Onshore Petroleum and Natural Gas Gathering and Boosting

Through our verification efforts, it has become apparent that the reporting of some of the throughput volumes for the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are incomplete in the sense that they do not include all the quantities of natural gas (and hydrocarbon liquids) transported from the facility (*i.e.,* leaving the facility). In some cases, this appears to be due to the specific wording of the reporting elements in existing 40 CFR 98.236(aa)(10)(ii) and (iv) that appear to limit the quantities to the quantities transported to four specific downstream endpoints (*e.g.,* processing plants). However, the EPA indicated in the preamble to the final rule that added the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment that the throughputs transported from the facility were intended to be the total quantities transported downstream (80 FR 64280, October 22, 2015). Therefore, be consistent with the EPA's original intent for these data elements, we are proposing to amend 40 CFR 98.236(aa)(10)(ii) and (iv) to clarify that the downstream endpoints listed in the current reporting elements are examples of potential destinations and to specify that the reported quantities should be the natural gas or hydrocarbon liquids, respectively, transported to downstream operations such as one of those endpoints. We are also proposing to add storage facilities to the list of downstream operations to make the list of examples more comprehensive. Finally, for consistency with the text in CAA section 136 and to help the EPA implement CAA section 136 in the future, we are proposing to amend 40 CFR 98.236(aa)(10)(ii) to specify that the natural gas is transported ''through the facility'' and then to a downstream operation. As a result of these proposed amendments, the reported quantities should include all natural gas and hydrocarbon liquids transported downstream from the facility (*i.e.,* leaving the basin or leaving the gathering system owner or operator).

In addition to reviewing the reported throughputs, we also reviewed the definitions in subpart W associated with the industry segment and the facility. For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, we found that the definitions for ''Gathering and boosting system'' and ''Gathering and boosting system owner or operator'' in 40 CFR 98.238 specified that an onshore petroleum and natural gas gathering and boosting system or owner or operator must receive natural gas or petroleum from an onshore petroleum and natural gas production facility. Those definitions would exclude facilities that receive natural gas or petroleum from other onshore petroleum and natural gas gathering and boosting facilities and do not receive any natural gas or petroleum from onshore petroleum and natural gas production facilities. Therefore, there are potentially entire onshore petroleum and natural gas gathering and boosting facilities or volumes of gas through onshore petroleum and natural gas gathering and boosting facilities that are unaccounted for under the existing rule. We are proposing to amend the definition of ''Gathering and boosting system'' and ''Gathering and boosting owner or operator'' in 40 CFR 98.238 to specify that these systems may receive natural gas and/or petroleum from one or more other onshore petroleum and natural gas gathering and boosting systems in addition to production facilities.

c. Onshore Natural Gas Processing

Subpart W currently requires onshore natural gas processing facilities to report the quantity of natural gas received at the gas processing plant in existing 40 CFR 98.236(aa)(3)(i), however, the rule does not currently specify whether the volume is all natural gas that enters the facility—including natural gas that passes through the facility without being processed further (*i.e.,* ''pass-through volumes'')—or just natural gas received for processing. As discussed in section III.U.1 of this preamble, to maintain consistency with subpart NN and reduce burden for fractionators, the EPA is proposing to revise 40 CFR 98.236(aa)(3)(i) to specify that the subpart W quantity of gas received is the gas received for processing and is also proposing that fractionators do not have to report a quantity under 40 CFR 98.236(aa)(3)(i) if they report under subpart NN. Subpart NN does not require reporting of the gas leaving the facility, but to maintain consistency in the interpretation of the throughputs, to date, the EPA has provided guidance to facilities that the volume reported in accordance with 40 CFR 98.236(aa)(3)(ii) is that which has been processed at the facility and should exclude volumes of gas that are of pipeline specification and only passed through the facility.

However, to be consistent with CAA section 136(f)(2), the throughput should include all volumes of natural gas which pass through the facility or are sent to sales. Therefore, considering the proposed amendments to 40 CFR 98.236(aa)(3)(i) and guidance that has been historically provided for 40 CFR 98.236(aa)(3)(ii), a new reporting element for natural gas processing throughput is needed to fully capture all volumes through the facility (*i.e.,* those that are processed and those that pass through the facility which are not processed). As such, we are proposing to add a new reporting element for the Onshore Natural Gas Processing industry segment in 40 CFR 98.236(aa)(3)(ix) to capture all natural gas that is processed and/or passed through the facility consistent with the text in CAA section 136 (*i.e.,* ''natural gas sent to sale from or through facilities'').

2. Onshore Natural Gas Processing and Natural Gas Distribution Throughputs Also Reported Under Subpart NN

Onshore Natural Gas Processing plants are required to report seven facility-level throughput-related items under subpart W, as specified in existing 40 CFR 98.236(aa)(3). These seven data reporting elements include: quantities of natural gas received and processed gas leaving the gas processing plant, cumulative quantities of NGLs received and leaving the gas processing plant, the average mole fractions of CH_4 and CO_2 in the natural gas received, and an indication of whether the facility fractionates NGLs. Natural Gas Distribution companies are also required to report seven throughput volumes under subpart W, as specified in existing 40 CFR 98.236(aa)(9). These seven data reporting elements include: the quantity of gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas delivered to end users; the quantity of gas transferred to third parties; the quantity of gas consumed by the LDC for operational purposes; and the quantity of gas stolen.

The EPA has received stakeholder comments related to some of these reporting elements.[124] These stakeholders have commented that the reporting elements included in subpart W are redundant with data reported elsewhere within the GHGRP, specifically under subpart NN (Suppliers of Natural Gas and Natural Gas Liquids). Subpart NN requires NGL fractionators and LDCs to report the quantities of natural gas and natural gas liquid products supplied downstream and their associated emissions. For example, for natural gas processing plants, commenters stated that both subparts require reporting of the volume of natural gas received and the volume of NGLs received. Subpart W also requires reporting of total NGLs leaving the processing plant, while subpart NN requires reporting of the volume of each individual NGL product supplied. For LDCs, these commenters have stated that some duplicative reporting is required as well. For example, commenters stated that both subparts require reporting of the volume of natural gas received, volume placed into and out of storage each year, and volume transferred to other LDCs or to a pipeline as well as some other duplicative data. In addition, commenters stated that the reporting elements included in subparts W and NN for LDCs are redundant with data reported to the EIA on Form EIA–176, the Annual Report of Natural and Supplemental Gas Supply and Disposition.[125] The commenters explained that subpart W and subpart NN collect nearly the same data, and stated that discrepancies between the data sets are due to the use of inconsistent terminology. Commenters also suggested that due to the redundancy and availability of data reported to the EIA for LDCs, the EPA should remove the throughput-related reporting requirements for the Natural Gas Distribution industry segment from the GHGRP altogether. Commenters added that if the requirements are maintained, the EPA should reconcile the terminology used within the GHGRP and clarify the reporting elements.

The EIA report is submitted in the spring of each year and covers the previous calendar year. After completing internal audits of the reports, EIA publishes the data for each LDC on its website in the fall. The EIA data provides detailed information on the volume of gas received, gas stored, gas removed from storage, gas deliveries by sector, and HHV data. The EPA previously reviewed the possibility of obtaining data by accessing existing Federal Government reporting and provided the following response in the subpart NN response to public comments document accompanying the 2009 Final Rule:[126]

- The EPA ''decided not to modify the final rule because collecting data directly in a central system will enable the EPA to electronically verify all data reported under this rule quickly and consistently, to use the information for non-statistical purposes, and to handle confidential business information in accordance with the Clean Air Act.''
- In the specific case of subpart NN, the EPA also ''determined that it could not rely on EIA data to collect facility-level data from fractionators and company-level data from LDCs.''
- Additionally, the EPA ''seeks data that is beyond what EIA collects, such as quality assurance information, verification data, and information on odorized propane'' and ''data on site-specific HHV and carbon content from those sites that choose to sample and

[124] See Docket Id. Nos. EPA–HQ–OA–2017–0190–46726, EPA–HQ–OA–2017–0190–1958, EPA–HQ–OA–2017–0190–2066 available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[125] Form EIA–176 is available at the U.S. EIA website at *https://www.eia.gov/survey/form/eia_176/form.pdf*; the Form EIA–176 Instructions are available at *https://www.eia.gov/survey/form/eia_176/instructions.pdf*.

[126] See page 7 of *EPA Response to Public Comment Vol. 39 Subpart NN* at *https://www.epa.gov/ghgreporting/ghgrp-2009-final-rule-response-comments-documents*, also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

test products rather than use default emission factors.''

After further review of the data available through EIA, the stakeholder comments described earlier in this section, and the reporting requirements in subpart W and subpart NN, the EPA is proposing to eliminate duplicative elements from subpart W for facilities that report to subpart NN, consistent with section II.C of this preamble. The EPA is proposing to amend the reporting requirements in 40 CFR 98.236(aa)(3) for Onshore Natural Gas Processing plants that both fractionate NGLs (approximately 100 of the 450 subpart W natural gas processing plants) and also report as a supplier under subpart NN. For this subset of facilities, the EPA reviewed the data from subpart W and subpart NN and determined that there are no gas processing plants that report as fractionators under subpart W that do not also report under subpart NN without supplying a valid explanation.[127] During this review, the EPA found that some of the data elements included in subpart W overlap with data elements in subpart NN. Specifically, the data elements in 40 CFR 98.236(aa)(3)(i), (iii) and (iv) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(a)(3), 98.406(a)(1) and (2), 98.406(a)(4)(i) and (ii), respectively.[128]

To eliminate reporting redundancies, the EPA is proposing several amendments to 40 CFR 98.236(aa)(3). First, to clarify which facilities have data overlap between subparts W and NN, the EPA is proposing to add a reporting element for natural gas processing plants at 40 CFR 98.236(aa)(3)(viii) to indicate whether they report as a supplier under subpart NN. Next, the EPA is proposing that facilities that indicate that they both fractionate NGLs and report as a supplier under subpart NN would no longer be required to report the quantities of natural gas received or NGLs received or leaving the gas processing plant as specified in 40 CFR 98.236(aa)(3)(i), (iii) and (iv); this data would continue to be reported under subpart NN as specified in 40 CFR 98.406(a)(3), 98.406(a)(1) and (2), 98.406(a)(4)(i) and (ii), respectively, thus, maintaining the ability to verify associated emissions reported under subpart W. See Table 3 of this preamble for more information.

These facilities would, however, be required to continue reporting the data elements specified in 40 CFR 98.236(aa)(3)(ii) and (v) through (viii), as these reporting elements do not overlap with subpart NN reporting elements. Natural gas processing plants that do not fractionate or that fractionate but do not report as a supplier under subpart NN would continue to report all of the reporting elements for natural gas processing plants as specified in 40 CFR 98.236(aa)(3).

The EPA is also proposing to remove the reporting elements for throughput for LDCs in 40 CFR 98.236(aa)(9). The EPA reviewed the data from subpart W and subpart NN and determined that there are no LDCs that report under subpart W that do not also report under subpart NN. In fact, an average of 385 LDCs report under subpart NN, while 170 LDCs report under subpart W. Subpart NN therefore provides more comprehensive coverage of the Natural Gas Distribution industry segment. Additionally, subpart NN has been in effect for LDCs since RY2011 while subpart W throughput information has only been collected since RY2015; thus, subpart NN has a more robust historical data set. During this review, the EPA determined that the data elements found in 40 CFR 98.236(aa)(9)(i) through (v) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(b)(1) through (3), 98.406(b)(5) and (6), and 98.406(b)(13). To eliminate reporting redundancies, the EPA is proposing to remove these reporting elements from subpart W.

Table 3 of this preamble shows all the duplicative data elements that the EPA is proposing to remove from subpart W for facilities that also report to subpart NN.

TABLE 3—LIST OF PROPOSED SUBPART W DATA ELEMENTS TO BE REMOVED WHERE ANALOGOUS SUBPART NN DATA ELEMENTS ARE REPORTED

Subpart W data elements proposed to be eliminated		Analogous Subpart NN data elements	
Citation	Description	Citation	Description
Local Distribution Companies			
§ 98.236(aa)(9)(i)	Quantity of natural gas received at all custody transfer stations.	§ 98.406(b)(1) § 98.406(b)(5).	Annual volume of natural gas received by the LDC at its city gate stations and Annual volume natural gas that bypassed the city gate(s).
§ 98.236(aa)(9)(ii)	Quantity of natural gas withdrawn from in-system storage.	§ 98.406(b)(3)	Annual volume natural gas withdrawn from on-system storage and annual volume of vaporized LNG withdrawn from storage.
§ 98.236(aa)(9)(iii)	Quantity of natural gas added to in-system storage.	§ 98.406(b)(2)	Annual volume of natural gas placed into storage or liquefied and stored.
§ 98.236(aa)(9)(iv)	Quantity of natural gas delivered to end users.	§ 98.406(b)(13)(i) through (iv).	Annual volume of natural gas delivered by the LDC to residential consumers, commercial consumers, industrial consumers, electricity generating facilities.

[127] One such explanation is that the gas processing plant fractionates NGLs to supply fuel for use entirely on-site (*i.e.,* the fuel is not supplied downstream). Due to definitional differences between the two subparts, this facility is defined as a fractionator for purposes of subpart W but is not a supplier that must report under subpart NN.

[128] While it is the EPA's intention that the reported quantity of natural gas received at the facility in existing 40 CFR 98.236(aa)(3)(i) should be the quantity of natural gas received for processing, consistent with the requirement to report the annual volume of natural gas received for processing in existing 40 CFR 98.406(a)(3), some reporters have indicated in correspondence with the EPA via e-GGRT that they are including gas that is received at but not processed by the onshore natural gas processing facility (*i.e.,* gas that was processed elsewhere and passes through the onshore natural gas processing facility). Therefore, to clarify the EPA's intention and reinforce the consistency of the subpart W and subpart NN quantities, the EPA is proposing to revise 40 CFR 98.236(aa)(3)(i) to indicate that that reported quantity should be natural gas received at the gas processing plant for processing in the calendar year.

TABLE 3—LIST OF PROPOSED SUBPART W DATA ELEMENTS TO BE REMOVED WHERE ANALOGOUS SUBPART NN DATA ELEMENTS ARE REPORTED—Continued

Subpart W data elements proposed to be eliminated		Analogous Subpart NN data elements	
Citation	Description	Citation	Description
§ 98.236(aa)(9)(v)	Quantity of natural gas transferred to third parties.	§ 98.406(b)(6)	Annual volume of natural gas delivered to downstream gas transmission pipelines and other LDCs.
Natural Gas Processing Plants That Fractionate NGLs			
§ 98.236(aa)(3)(i)	Quantity of natural gas received	§ 98.406(a)(3)	Annual volume of natural gas received for processing.
§ 98.236(aa)(3)(iii)	Cumulative quantity of all NGLs (bulk and fractionated) received.	§ 98.406(a)(2) § 98.406(a)(4)(i).	Annual quantity of each NGL product received and annual quantities of y-grade, o-grade and other bulk NGLs received.
§ 98.236(aa)(3)(iv)	Cumulative quantity of all NGLs (bulk and fractionated) leaving.	§ 98.406(a)(1) § 98.406(a)(4)(ii).	Annual quantity of each NGL product supplied and annual quantities of y-grade, o-grade and other bulk NGLs supplied.

The EPA is also proposing to remove the reporting elements for the volume of natural gas used for operational purposes and natural gas stolen specified in 40 CFR 98.236(aa)(9)(vi) and (vii). These reporting elements are unique to subpart W, require additional burden to estimate, and have not been used for the EPA's analyses of the subpart W data. As a result of proposing to remove all of the 40 CFR 98.236(aa)(9) data elements for the reasons explained in this section of this preamble, the EPA proposes to reserve paragraph 40 CFR 98.236(aa)(9).

3. Onshore Natural Gas Transmission Pipeline Storage Throughputs

Similar to Natural Gas Distribution facilities, Onshore Natural Gas Transmission Pipeline facilities are currently required to report five throughput volumes under subpart W, as specified in existing 40 CFR 98.236(aa)(11). These five data reporting elements include: the quantity of natural gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas transferred to third parties; and the quantity of gas consumed by the transmission pipeline facility for operational purposes. As noted in section III.U.1 of this preamble, the EPA has received stakeholder feedback on the reporting elements for Natural Gas Distribution facilities, including questions submitted to the GHGRP Help Desk, regarding the term ''in-system storage.'' Although the questions were specific to Natural Gas Distribution facilities, the term ''in-system storage'' is also included in the throughput reporting elements for Onshore Natural Gas Transmission Pipeline facilities at existing 40 CFR 98.236(aa)(11)(ii) and (iii). After consideration of the stakeholder feedback, the EPA is proposing to revise these provisions to better characterize the existing term ''in-system.'' Specifically, we are proposing to amend 40 CFR 98.236(aa)(11)(ii) and (iii) to replace the term ''in-system'' with clarifying language that specifies withdrawals/additions of natural gas from storage are referring to Underground Natural Gas Storage and LNG Storage facilities that are owned and operated by the onshore natural gas transmission pipeline owner or operator that do not report under subpart W as direct emitters themselves. These amendments are expected to improve data quality consistent with section II.D of this preamble.

V. Other Proposed Minor Revisions or Clarifications

See Table 4 of this preamble for the miscellaneous minor technical corrections not previously described in this preamble that we are proposing throughout subpart W, consistent with section II.D of this preamble.

TABLE 4—PROPOSED TECHNICAL CORRECTIONS TO SUBPART W

Section (40 CFR)	Description of proposed amendment
98.230(a)(2)	Revise the instance of "well pad" to read "well-pad" to correct inconsistency in the term.
98.230(a)(9)	Remove the ")" after "GOR" to correct a typographical error.
98.232 introductory text	Add reference to paragraph (l) of this section to clarify that annual reports must include the information specified in paragraph (l) if applicable.
98.232(c)(17), (d)(5) and (j)(3)	Revise the instances of "acid gas removal vents" to read "acid gas removal unit vents" for consistency with the defined term "Acid gas removal unit (AGR)" in 40 CFR 98.238.
98.233(d)	Revise the instances of "AGR unit" to read "AGR" for consistency with the defined term "Acid gas removal unit (AGR)" in 40 CFR 98.238.
98.233(e)(1)(x), 98.236(e)(1)(xi) and (xii)	Add "at the absorber inlet" to the end of the paragraph to clarify the location for the wet natural gas temperature and pressure to be used for modeling.
98.233(j), 98.236(j)	Revise the instances of "oil," "oil/condensate," and "liquid" to read "hydrocarbon liquids" for consistency with the requirement in 40 CFR 98.233(j) to calculate emissions from "atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids," as noted in the 2015 amendments to subpart W (80 FR 64272, October 22, 2015).
98.233(k)	Revise the introductory sentence in this section to specify that 40 CFR 98.233(k) does not apply to condensate storage tanks that route emissions to flares or other controls for consistency with proposed amendment that would move procedures for calculating flared emissions from 40 CFR 98.233(k) to 40 CFR 98.233(n).

TABLE 4—PROPOSED TECHNICAL CORRECTIONS TO SUBPART W—Continued

Section (40 CFR)	Description of proposed amendment
98.233(n)(5)	Correct the cross reference in the definition of the equation variable "Y_j" from paragraph (n)(1) to (n)(2).
98.233(o) introductory text and (p) introductory text.	Move the last sentence in each paragraph to be the second sentence to clarify that the calculation methodology for compressors routed to flares, combustion, or vapor recovery systems apply to all industry segments.
98.233(o) introductory text and (p) introductory text, 236(o)(2)(ii) and (p)(2)(ii).	Revise the instances of "vapor recovery" to read "vapor recovery system" to correct inconsistency in the term.
98.233(p)(1)(i)	Correct the internal cross reference from paragraph (o) to paragraph (p).
98.233(p)(4)(ii)(C)	Add missing "in" to read "according to methods set forth in § 98.234(d)."
98.233(r) introductory text	Revise the instance of "CH" in the third sentence to read "CH_4" to correct a typographical error.
98.233(r), equations W–32A and W–32B	Correct the cross reference in the definition of the equation variable "$E_{s,MR,i}$" and the equation variable "CountMR" from paragraph (q)(9) to (q)(2)(xi) or (q)(3)(vii)(B).
98.233(r)(6)(ii)	Add reference to components listed in 40 CFR 98.232(i)(3), for consistency with proposed amendments to 40 CFR 98.233(r)(6)(i).
98.233(t)(2)	Revise the definition of equation variable "Z_a" to include the sentence following the definition of that variable to correct a typographical error.
98.233(u)(2)(ii)	Format the heading to be in italicized text.
98.233(z)	Revise the instances of "high heat value" to read "higher heating value" to correct inconsistency in the term.
98.233(z), equations W–39A and W–39B	Remove unnecessary "constituent" from "CO_2 constituent" and "methane constituent" and remove "gas" from "gas hydrocarbon constituent." Add missing "the" to read "to the combustion unit" in several variable definitions.
98.234(e)	Renumber the Peng Robinson equation of state from equation W–41 to equation W–46 to provide space for five new equations related to new source types in proposed 40 CFR 98.233(dd) and (ee).
98.234(f)	Remove and reserve paragraph for provisions for best available monitoring methods for RY2015, as reports for that reporting year can no longer be submitted to the EPA.
98.234(g)	Remove and reserve paragraph for provisions for best available monitoring methods for RY2016, as reports for that reporting year can no longer be submitted to the EPA.
98.236 introductory text	Add missing "than" to read "report gas volumes at standard conditions rather than the gas volumes at actual conditions"
98.236(c)(5)(i) through (iii)	Edits to explicitly state that the reporting requirements in this section apply to pneumatic pumps that are vented direct to atmosphere and for which emissions are calculated using the default emission factor (Calculation Method 3). Revise "operational" to "pumping liquid" in the description of the reported time element in 98.236(c)(5)(i) to be consistent with the proposed change described in section III.E.3 of this preamble for Calculation Method 2.
98.236(d)(2)(iii)(B)	Revise "natural gas flow rate" to read "natural gas feed flow rate" for consistency with the parameters listed in 40 CFR 98.233(d)(4)(i).
98.236(e)(1) and (2)	Revise the instances of "vented to" a control device, vapor recovery, or a flare to read "routed to" to correct inconsistency in the phrases "vented to" and "routed to." Revise the instances of "vapor recovery device" to read "vapor recovery system" to correct inconsistency in the term.
98.236(j)(2)	Clarify that the reported information in paragraphs (j)(1)(i) through (xvi) should only include those atmospheric storage tanks with emissions calculated using Calculation Method 3.
98.236(k)(1)(iii)	Correct the internal cross reference from "§ 98.233(k)(2)" to "§ 98.233(k)(1)."
98.236(k)(2)	Add a cross reference to § 98.233(k)(2) and revise sentence to specify that the reported method used to measure leak rates should be one provided in that section.
98.236(l)(1), (2), (3), and (4) introductory text	Revise the instances of "vented to a flare" to read "routed to a flare" to correct inconsistency in the phrases "vented to" and "routed to."
98.236(p)(3)(ii)	Add a missing period at the end of the sentence.
98.236(bb)	Clarify that reporting for missing data procedures includes the procedures used to substitute an unavailable value of a parameter (per 40 CFR 98.235(h)).
98.236(cc)	Correct the cross references from paragraph (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), and (l)(4)(iii) to (l)(1)(v), (l)(2)(v), (l)(3)(iv), and (l)(4)(iv), respectively.
98.238	Remove the second definition of "Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements" to eliminate an inadvertent identical duplicative definition.
Tables W–1 through W–7 to subpart W of part 98.	Replace Tables W–1 through W–7 with new Tables W–1 through W–6 to reorganize and consolidate the emission factor tables so that there are separate tables by pollutant (whole gas, THC, and CH_4) and by type of factor (population and leaker emission factors). Update cross references to these tables accordingly throughout subpart W.

IV. Schedule for the Proposed Amendments

The EPA is planning to consider the comments on these proposed changes, and, if any of the proposed amendments are finalized, to respond to the comments and promulgate any amendments by August 16, 2024.[129] We

[129] Section 136(h) of the CAA requires subpart W to be revised as specified in that provision "not later than 2 years after the date of enactment of this

are proposing that these amendments would become effective on January 1, 2025, and that reporters would implement the majority of the changes beginning with reports prepared for RY2025 and submitted March 31, 2026. The exception is the proposed reporting of the quantities of natural gas, crude oil, and condensate produced that is sent to sale in the calendar year for each well permanently shut-in and plugged (proposed 40 CFR 98.236(aa)(1)(iii)(C) through (E) and proposed 40 CFR 98.236(aa)(2)(iv) through (vi)); those provisions would become effective on January 1, 2025 and reporters would include that information in their reports prepared for RY2024 and submitted March 31, 2025. The submission date for RY2025 reports is over a year after we expect a final rule based on this proposal to be finalized, if finalized, thus providing a reasonable period for reporters to adjust to any finalized amendments. The proposed effective date would also allow ample time for the EPA to implement the changes into e-GGRT.

We are likewise proposing that the proposed CBI determinations discussed in section VI of this preamble would become effective on January 1, 2025. The majority of the determinations are for new or revised data elements that would be included in annual GHG reports prepared for RY2025 and submitted March 31, 2026. The determinations related to the reporting of the quantities of natural gas, crude oil, and condensate produced that is sent to sale in the calendar year for each well permanently shut-in and plugged would apply the first year that data is collected (*i.e.,* RY2024 data submitted on or before March 31, 2025). Finally, there is one circumstance, discussed in detail in section V of this preamble, where the proposed determination covers data included in annual GHG reports submitted for prior years. In all cases, the proposed determinations for the data that the EPA has already received for these prior years or receives going forward for any reporting year would become effective on January 1, 2025.

section.'' The section was enacted via Public Law No: 117–169 on August 16, 2022.

V. Proposed Confidentiality and Reporting Determinations for Certain Data Reporting Elements

A. Overview and Background

In this action we are proposing confidentiality determinations for new or substantially revised data elements that would be collected under the proposed rule amendments.

1. Background on EPA's Treatment of Data Collected Under Part 98

Following proposal of part 98 (74 FR 16448, April 10, 2009), the EPA received comments addressing the issue of whether certain data could be entitled to confidential treatment. In response to these comments, the EPA stated in the preamble to the 2009 Final Rule (74 FR 56387, October 30, 2009) that through a notice and comment process, we would establish those data elements that are entitled to confidential treatment. This proposal is one of a series of rules dealing with confidentiality determinations for data reported under part 98, including subpart C (General Stationary Fuel Combustion) and W (Petroleum and Natural Gas Systems).

- 75 FR 39094, July 7, 2010. Describes the data categories and category-based determinations the EPA developed for the part 98 data elements.
- 76 FR 30782, May 26, 2011; hereafter referred to as the ''2011 Final CBI Rule.'' Assigned data elements to data categories and published the final CBI determinations for the data elements in 34 part 98 subparts, except for those data elements that were assigned to the ''Inputs to Emission Equations'' data category.
- 77 FR 48072, August 13, 2012. Finalized confidentiality determinations for data elements reported under nine subparts, including subpart W, except for those data elements that are ''inputs to emission equations''.
- 78 FR 69337, November 29, 2013. Finalized determinations for new and revised data elements in 15 subparts, including subpart C, except for those data elements that are ''inputs to emission equations''.
- 79 FR 63750, October 24, 2014. Revised recordkeeping and reporting requirements for ''inputs to emission equations'' for 23 subparts and finalized confidentiality determinations for new data elements in 11 subparts, including subpart W.
- 79 FR 70352, November 25, 2014. Finalized confidentiality determinations for new and substantially revised data elements in subpart W.
- 80 FR 64262, October 22, 2015. Finalized confidentiality determinations for new data elements in subpart W.
- 81 FR 86490, November 30, 2016. Finalized confidentiality determinations for new or substantially revised data elements in subpart W.
- 81 FR 89188, December 9, 2016. Finalized confidentiality determinations for new or substantially revised data elements in 18 subparts, including subpart C.
- 87 FR 36920, June 21, 2022. Describes the EPA's revised approach to assessing data in response to *Food Marketing Institute* v. *Argus Leader Media*, 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[130]

To support the proposed amendments to part 98 described in section III of this preamble, we are proposing confidentiality determinations or ''emission data'' designations, in keeping with our existing approach (see section V.B.1 of this preamble), for the following:

- New or substantially revised reporting requirements (*i.e.,* the proposed change requires additional or different data to be reported);
- Existing reporting requirements for which the EPA did not previously finalize a confidentiality determination or ''emission data'' designation.

Further, we propose to designate certain new or substantially revised data elements as ''inputs to emission equations'' falling within the definition of ''emission data.'' For each element that we propose would fall in this category, we further propose whether the data element would be directly reported to the EPA or whether it would be entered into e-GGRT's Inputs Verification Tool (IVT) (see section V.C of this preamble for a discussion of ''inputs to emission equations'').

2. Summary of Data Elements Affected by the Proposed Amendments to Part 98

Table 5 of this preamble provides the number of affected data elements and the affected subparts for each of these proposed actions.

[130] See Docket Id. No. EPA–HQ–OAR–2023–0234.

TABLE 5—SUMMARY OF PROPOSED ACTIONS RELATED TO DATA CONFIDENTIALITY

Proposed actions related to data confidentiality	Number of data elements [a]	Subpart(s)
New or substantially revised reporting requirements for which the EPA is proposing a confidentiality determination or ''emission data'' designation.	522	C, W
Existing reporting requirements for which the EPA is proposing a confidentiality determination or ''emission data'' designation because the EPA did not previously make a confidentiality determination or ''emission data'' designation.	1	W
New or substantially revised reporting requirements that the EPA is proposing be designated as ''inputs to emission equations'' and for which the EPA is proposing reporting determinations.	162	W

[a] These data elements are individually listed in the memoranda: (1) *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems* (2) *Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234).

The majority of the proposed determinations would apply at the same time as the proposed schedule described in section IV of this preamble. In the case where the EPA is re-proposing from the June 2022 proposal a determination for an existing data element where one was not previously made, the proposed determination would be effective on January 1, 2025, and would apply to annual reports submitted for RY2025, as well as all prior years that the data were collected. The determination related to the treatment of this prior year data will not change how the data was actually treated by the Agency, it will only conform the text of the determination to the actual confidentiality status the data has had since it was first collected.

B. Proposed Confidentiality Determinations and Emissions Data Designations

1. Proposed Approach

The EPA is proposing to assess the data elements in this proposed rule, following the same approach as described in the 2022 Proposed Rule (87 FR 36920, June 21, 2022). In that proposal, the EPA described a revised approach to assessing data in response to *Food Marketing Institute* v. *Argus Leader Media*, 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[131]

We propose to continue identifying new and revised reporting elements that qualify as ''emission data'' (*i.e.,* data necessary to determine the identity, amount, frequency, or concentration of the emission emitted by the reporting facilities) by evaluating the data for assignment to one of the four data categories designated by the 2011 Final CBI Rule to meet the CAA definition of ''emission data'' in 40 CFR 2.301(a)(2)(i)[132] (hereafter referred to as ''emission data categories''). Refer to section II.B of the July 7, 2010, proposal for descriptions of each of these data categories and the EPA's rationale for designating each data category as ''emission data.''

For data elements designated as ''inputs to emission equations,'' the EPA proposes to assign data elements to one of two subcategories, including data elements entered into IVT and those directly reported to the EPA. See section V.C of this preamble for further descriptions of each of these data categories.

For new or revised data elements that the EPA does not propose to designate as ''emission data'' or ''inputs to emission equations,'' the EPA proposes to assess each individual reporting element according to the Argus Leader standard, established in 2019. Accordingly, we propose to evaluate each new or revised data element not designated as ''emission data'' or ''inputs to emission equations'' individually to determine whether the information is customarily and actually treated as private by the reporter and are proposing a confidentiality determination based on that evaluation.

Consistent with the 40 CFR part 2 procedures, this rulemaking provides an opportunity for affected stakeholders to justify any confidentiality claim they may have for the data they are required to submit under parts 98 (except for emission data which are not entitled to confidential treatment).

2. Proposed Confidentiality Determinations and ''Emission Data'' Designations

In this section, we discuss the proposed confidentiality determinations and ''emission data'' designations for 522 new or substantially revised data elements. We also discuss one existing data element (i.e., not proposed to be substantially revised) for which for no determination has been previously established.

a. Proposed Confidentiality Determinations and ''Emission Data'' Designations for New or Substantially Revised Data Reporting Elements

For the 522 new and substantially revised data elements, the EPA is proposing ''emission data'' designations for 277 data elements and confidentiality determinations for 245 data elements. The EPA is proposing to designate 277 new or substantially revised data elements as ''emission data'' by assigning the data elements to three emission data categories (established in the 2011 Final CBI Rule as discussed in section V.B.1 of this preamble), as follows:

- 114 data elements that are proposed to be reported under subpart W are proposed to be assigned to the ''Emissions'' emission data category;

[131] In the 2022 Proposed Rule (87 FR 36920, June 21, 2022), the EPA proposed that the *Argus Leader* decision does not affect our historical approach to designating data elements as ''inputs to emission equations'' or our previous approach for designating new and revised reporting requirements as ''emission data,'' which are described in the July 7, 2010 proposal (75 FR 39094), 2011 Final CBI Rule, and October 24, 2014 final rule (79 FR 63750). For reporting elements that the EPA did not designate as ''emission data'' or ''inputs to emission equations,'' the EPA proposed to revise the historical approach to assign data elements to data categories established in the 2011 Final CBI Rule, and instead proposed to assess each individual reporting element according to the *Argus Leader* criteria.

[132] See section I.C of the July 7, 2010 proposal (75 FR 39100) for a discussion of the definition of ''emission data.'' As discussed therein, the relevant paragraphs (to the GHGRP) of the CAA definition of ''emission data'' include 40 CFR 2.301(a)(2)(i)(A) and (C), as follows: (A) ''Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing;'' and (C) ''A general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).''

• 126 data elements that are proposed to be reported under subparts C and W are proposed to be assigned to the ''Facility and Unit Identifier Information'' emission data category; and

• 37 data elements that are proposed to be reported under subparts C and W are proposed to be assigned to the ''Calculation Methodology and Methodological Tier'' emission data category.

Refer to Table 1 in the memorandum, Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234), for a list of these 277 data elements proposed to be designated as ''emission data,'' the proposed emission data category assignment for each data element, and the EPA's rationale for each proposed ''emission data'' category assignment.

The remaining 245 new and substantially revised data elements proposed to be reported under subpart W are not proposed to be designated as ''emission data,'' or ''inputs to emission equations.'' Rather, this proposal assesses each individual reporting element according to the Argus Leader criteria as discussed in section V.B.1 of this preamble. Refer to Table 2 in the memorandum, Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, to see a list of these 245 specific data elements, the proposed confidentiality determination for each data element, and the EPA's rationale for each proposed confidentiality determination. These determinations show the data elements that would be entitled to confidential treatment if submitted to the EPA, and those that the EPA would publish.

b. Proposed Confidentiality Determinations for Existing Part 98 Data Elements for Which No Determination Has Been Previously Established

We are re-proposing one confidentiality determination for a single data element currently reported under subpart W for which no confidentiality determination or ''emission data'' designation has been previously finalized under part 98. In the 2022 Proposed Rule, we reviewed previous rulemakings and found 26 data elements where a confidentiality determination or ''emission data'' designation had not been made under subpart W. In the 2022 Proposed Rule, we had evaluated these data elements and proposed either confidentiality determinations or ''emission data'' designations, using the categories established in the 2011 Final CBI Rule. This proposal would revise 25 out of 26 of these data elements. Therefore, these 25 revised data elements are included in the proposed confidentiality determinations and ''emission data'' designations discussed in section V.B.2.a of this preamble, consistent with our approach for other data elements that we are proposing to revise in this proposed rulemaking. That leaves one existing data element for which no previous determination has been finalized. We assessed the one remaining data element with no existing confidentiality determination according to the Argus Leader criteria and are re-proposing the confidentiality determination from the June 2022 Proposed Rule. Refer to Table 3 in the memorandum, Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234), for details of the confidentiality determinations.

C. Proposed Reporting Determinations for Inputs to Emissions Equations

In this section, we discuss data elements that the EPA proposes to assign to the ''Inputs to Emission Equations'' data category. This data category includes data elements that are the inputs to the emission equations used by sources that directly emit GHGs to calculate their annual GHG emissions.[133] As discussed in section VI.B.1 of the 2022 Proposed Rule (87 FR 36920, June 21, 2022), the EPA determined that the Argus Leader standard does not apply to our approach for handling data elements assigned to the ''Inputs to Emission Equations'' data category.

The EPA organizes data assigned to the ''Inputs to Emission Equations'' data category into two subcategories. The first subcategory includes ''inputs to emission equations'' that must be directly reported to the EPA. This is done in circumstances where the EPA has determined that the data elements do not meet the criteria necessary for them to be entered into the IVT system. These ''inputs to emission equations,'' once received by the EPA, are not entitled to confidential treatment. The second subcategory includes ''inputs to emission equations'' that are entered into IVT. These ''inputs to emission equations'' are entered into IVT to satisfy the EPA's verification requirements. These data must be maintained as verification software records by the submitter, but the data are not included in the annual report that is submitted to the EPA. This is done in circumstances where the EPA has determined that the data elements meet the criteria necessary for them to be entered into the IVT system. Refer to the memorandum, Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234), for a discussion of the criteria established in 2011 for evaluating whether data assigned to the ''Inputs to Emission Equations'' data category should be entered into the IVT system.

We are proposing to assign 162 new or substantially revised data elements in subparts C and W to the ''Inputs to Emission Equations'' data category. We evaluated each of the 162 proposed new or substantially revised data elements assigned to the ''Inputs to Emission Equations'' data category and determined that none of these 162 data elements meet the criteria necessary for them to be entered into the IVT system; therefore, we propose that these 162 data elements be directly reported to the EPA. As ''inputs to emission equations'' are emissions data, these 162 data elements would not be eligible for confidential treatment once directly reported to the EPA, and they would be published once received by the EPA. Refer to Table 1 in the memorandum, Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2023–0234), for a list of these 162 data elements proposed to be designated as ''inputs to emission equations'' that would be directly reported to the EPA and the EPA's

[133] For facilities that directly emit GHGs, part 98 includes equations that facilities use to calculate emission values. The ''Inputs to Emission Equations'' data category includes the data elements that facilities would be required to enter in the equations to calculate the facility emissions values, e.g., monthly consumption or production data or measured values from required monitoring, such as carbon content. See 75 FR 39094, July 7, 2010 for a full description of the ''Inputs to Emission Equations'' data category.

rationale for the proposed reporting determinations.

D. Request for Comments on Proposed Amendments to 40 CFR Part 2, Category Assignments, Confidentiality Determinations, or Determinations of Inputs To Be Reported

We solicit comment on the proposed categories, confidentiality, and reporting determinations in this proposed rule. By proposing confidentiality determinations prior to data reporting through this proposal and rulemaking process, we are providing potential reporters an opportunity to submit comments, particularly comments addressing any data elements not entitled to confidential treatment under this proposal, but which reporters customarily and actually treat as private. Likewise, we provide potential reporters an opportunity to submit comments on whether there are disclosure concerns for data elements proposed to be categorized as ''inputs to emission equations'' that we propose would be directly reported to the EPA via annual reports and subsequently released by the EPA. This opportunity to submit comments is intended to provide reporters with the opportunity to substantiate their confidentiality claims that would ordinarily be afforded to reporters when the EPA considers claims for confidential treatment of information in case-by-case confidentiality determinations under 40 CFR part 2. In addition, the comment period provides an opportunity to respond to the EPA's proposed determinations with more information for the Agency to consider prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be reporters' only opportunity to substantiate a confidentiality claim for data elements included in this proposed rule where a confidentiality determination or reporting determination is being proposed. Upon finalizing the confidentiality determinations and reporting determinations of the data elements identified in this proposed rule, the EPA will release or withhold these data in accordance with 40 CFR 2.301(d), which contains special provisions governing the treatment of part 98 data for which confidentiality determinations have been made through rulemaking pursuant to CAA sections 114 and 307(d).

If members of the public have reason to believe any data elements in this proposed rule that are proposed to be treated as confidential are not customarily and actually treated as private by reporters, please provide comment explaining why the Agency should not provide an assurance of confidential treatment for such data. Likewise, if members of the public have reason to disagree with the EPA's proposal that ''inputs to emission equations'' qualify to be entered into IVT and retained as verification software records instead of being directly reported to the EPA, please provide comment explaining why the ''inputs to emission equations'' do not qualify to be entered into IVT, should be directly reported to the EPA, and subsequently released by the EPA. As described in section III.D, the EPA is proposing revisions to several existing data elements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments such that the data would be reported by facilities at the site level. Under the current requirements, facilities report much of this information aggregated across multiple sites. Given that the proposed revisions would require that facilities report more specific information, the EPA is requesting comment on the confidentiality and reporting determinations for this site-level reporting. For any revised data elements that fall into an ''emissions data'' category, the EPA is proposing that the data would continue to be released regardless of whether it is collected at the site level or aggregated across sites. However, for data elements that do not fall into an ''emissions data'' category, the EPA is seeking comment regarding whether any of these particular data elements are customarily and actually treated as private together with specific information supporting this position when reported at the site level. The EPA believes that the information in this category that would not already be released as emission data is not information that is customarily and actually treated as confidential by submitters, even at the site level. The EPA is aware of outlets where much of this information is already released publicly, such as State and local records including records from oil and gas permitting authorities, taxing authorities, and environmental agencies, U.S. Securities and Exchange Commission (SEC) forms for publicly traded companies, company websites, data services such as Enverus, S&P Global/IHS Markit, Rystad Energy and Wood Mackenzie, and publications like Oil &Gas Journal, Petroleum Economist, and Upstream. Upon consideration of comments, the EPA will consider releasing this information directly as proposed, or other options that may take into account confidentiality concerns, but still release as much of this valuable information to the public as possible.

When submitting comments regarding the confidentiality determinations or reporting determinations we are proposing in this action, please identify each individual proposed new, revised, or existing data element you consider to be confidential or do not consider to be ''emission data'' in your comments. If the data element has been designated as ''emission data,'' please explain why you do not believe the information should be considered ''emission data'' as defined in 40 CFR 2.301(a)(2)(i). If the data has not been designated as ''emission data'' and is proposed to not be entitled to confidential treatment, please explain specifically how the data element is commercial or financial information that is both customarily and actually treated as private. Particularly describe the measures currently taken to keep the data confidential and how that information has been customarily treated by your company and/or business sector in the past. This explanation is based on the requirements for confidential treatment set forth in *Argus Leader*. If the data element has been designated as an ''input to an emission equation'' (i.e., not entitled to confidential treatment) and proposed to be directly reported to the EPA via annual reports and subsequently released by the EPA, please explain specifically why there are disclosure concerns.

Please also discuss how this data element may be different from or similar to data that are already publicly available, including data already collected and published annually by the GHGRP, as applicable. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for confidential treatment. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or Federal agency publication, provide the title, volume number (if applicable), author(s), publisher, publication date, and International Standard Book Number

(ISBN) or other identifier. For data published on a website, provide the address of the website, the date you last visited the website and identify the website publisher and content author. Please avoid conclusory and unsubstantiated statements, or general assertions regarding the confidential nature of the information.

Finally, we are not proposing new confidentiality determinations and reporting determinations for data reporting elements proposed to be unchanged or minimally revised because the final confidentiality determinations and reporting determinations that the EPA made in previous rules for these unchanged or minimally revised data elements are unaffected by this proposed amendment and will continue to apply. The minimally revised data elements are those where we are proposing revisions that would not require additional or different data to be reported. For example, we are proposing to amend 40 CFR 98.236(aa)(5)(ii) to clarify that facilities reporting to the Underground Natural Gas Storage industry segment must report the quantity of natural gas withdrawn from storage and sent to sale in the calendar year. As discussed in section III.U of this preamble, we are proposing several text edits to include ''natural'' before each instance of ''gas'' and to use the phrase ''sent to sale'' for consistency with CAA section 136 language. This proposed change is for consistency in language and would not affect the data collected or the interpretation of the terms, and therefore we are not proposing a new or revised confidentiality determination. However, we are soliciting comment on any cases where a minor revision would affect the previous confidentiality determination or reporting determination. In your comments, please identify the specific data element, including name and citation, and explain why the minor revision would affect the previous confidentiality determination or reporting determination.

VI. Impacts of the Proposed Amendments

The proposed revisions would amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule consistent with CAA section 136(h) to ensure that reporting under subpart W is based on empirical data and accurately reflects total CH4 emissions and waste emissions from applicable facilities, and to allow owners and operators of applicable facilities to submit empirical emissions data that appropriately could demonstrate the extent to which a charge is owed in future implementation of CAA section 136. These proposed revisions include improving the existing calculation, recordkeeping, and reporting requirements. The EPA is proposing amendments to part 98 in order to implement improvements to the GHGRP, including revisions to update existing emission factors and emissions estimation methodologies, revisions to require reporting of additional data for new emission sources and address potential gaps in reporting, and revisions to collect data that would improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates, verification of collected data, or to complement or inform other EPA programs. The EPA is also proposing revisions that would improve implementation of the program, such as those that would update applicability estimation methodologies, provide flexibility for or simplifying calculation and monitoring methodologies, streamline recordkeeping and reporting, and other minor technical corrections or clarifications identified as a result of working with the affected sources during rule implementation and outreach. The EPA anticipates that the proposed revisions to improve accuracy of reporting would increase costs for reporters. To the extent consideration of costs is relevant to the EPA's proposal for meeting its obligation under CAA section 136(h), these anticipated costs are reasonable.

As discussed in section V of this preamble, we are proposing to implement these changes beginning in RY2025. Costs have been estimated over the three years following the year of implementation. The incremental implementation costs for each reporting year are summarized in Table 6 of this preamble. The estimated annual average labor burden is $41.4 million per year and the annual average labor burden per reporter is $13,500. The incremental burden for subpart W and the incremental costs per reporter are shown in Table 6 of this preamble.

TABLE 6—TOTAL INCREMENTAL LABOR BURDEN FOR REPORTING YEARS 2025–2027

[$2021/year]

Cost summary	RY2025	RY2026	RY2027	Annual average
Burden by Year	$41.4 million	$41.4 million	$41.4 million	$41.4 million.
Number of Reporters	3,077	3,077	3,077	3,077.
Incremental Labor Cost per Reporter	$13,500	$13,500	$13,500	$13,500.

There is an additional annualized incremental burden of $50.9 million for capital and operation and maintenance (O&M) costs, which reflects changes to applicability and monitoring. Including capital and O&M costs, the total annual average burden is $92.3 million over the next 3 years.

The total incremental burden and burden by reporter per subpart W industry segment are shown in Table 7 of this preamble.

TABLE 7—TOTAL INCREMENTAL BURDEN BY INDUSTRY SEGMENT AND BY REPORTER

[$2021/year] [a]

Industry segment	Count of reporters [b]	Labor costs [c]	Capital and O&M (annualized)	Total annual cost	Total annual cost per reporter
Onshore Petroleum and Natural Gas Production	777	$27,957,105	$36,301,841	$64,258,946	$82,701
Offshore Petroleum and Natural Gas Production	141	3,793	0	3,793	27
Onshore Petroleum and Natural Gas Gathering and Boosting	361	1,490,222	4,013,157	5,503,379	15,245
Onshore Natural Gas Processing	515	8,768,994	3,936,094	12,705,088	24,670
Onshore Natural Gas Transmission Compression	1,008	2,755,614	6,028,399	8,784,013	8,714
Natural Gas Transmission Pipeline	53	87,596	187	87,783	1,656
Underground Natural Gas Storage	68	167,324	417,348	584,673	8,598
LNG Import and Export Equipment	11	4,605	18,649	23,254	2,114
LNG Storage	7	14,714	20,953	35,667	5,095
Natural Gas Distribution	164	163,069	161,370	324,439	1,978
Total	3,077	41,413,037	50,897,998	92,311,035	30,000

[a] Includes estimated increase in costs following implementation of revisions in RY2025.
[b] Counts are based on GHGRP data reported in RY2020 and 567 new facilities, as detailed in the memorandum, *Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*
[c] Initial year and subsequent year labor costs are $41.4 million per year.

A full discussion of the cost and emission impacts may be found in the memorandum, *Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. The EPA is requesting comment on the assumptions and methodology used in this memorandum.

The national costs of the proposed rule reflect the fact that there are a large number of affected entities, but per entity costs are low. To further assess the economic impacts of the proposed rule, the EPA conducted a screening analysis comparing the estimated total annualized compliance costs for the petroleum and natural gas systems industry segments with industry mean cost-to-revenue ratios based on the total facility costs that are applicable to parent entities in each segment. This analysis shows that the per-entity impacts within each industry segment are low. These low mean cost-to-revenue ratios indicate that the proposed rule is unlikely to result in significant changes in parent entity production decisions or other choices that would result in significant fluctuations in prices or quantities in affected markets.

TABLE 8—MEAN CRRS FOR PARENT ENTITIES BY INDUSTRY SEGMENT, ALL BUSINESS SIZES

Industry segment	Mean CRR (standard error)
Onshore petroleum and natural gas production	0.87% (0.81–0.92%)
Offshore petroleum and natural gas production	0.06% (0.04–0.09%)
Onshore petroleum and natural gas gathering and boosting	0.41% (0.33–0.48%)
Onshore natural gas processing	0.50% (0.37–0.63%)
Onshore natural gas transmission compression	0.09% (0.06–0.12%)
Onshore natural gas transmission pipeline	0.07% (0.05–0.10%)
Underground natural gas storage	0.07% (0.05–0.09%)
LNG import and export equipment	0.01% (0.00–0.01%)
LNG storage	0.00% (0.00–0.00%)
Natural gas distribution	0.08% (0.05–0.10%)
All segments	0.60% (0.55–0.64%)

CRR = cost-to-revenue ratio.

The EPA also evaluated the mean costs to individual facilities and mean costs to parents (accounting for multiple owned facilities) for reporters (shown in Table 9 of this preamble), which are relatively small given the high revenues of parent companies within the petroleum and natural gas systems sector. There are currently 2,322 existing facilities reporting to subpart W that are owned by approximately 600 parent entities. Based on a review of revenue data available for approximately 585 parent entities, the proposed rule costs represent less than one percent of the total annual revenue for entities that would be reporting under subpart W.

TABLE 9—ESTIMATED MEAN COSTS AND REVENUES FOR FACILITY AND PARENT ENTITIES, ALL SEGMENTS

Metric	Estimated values (95% confidence interval)
Mean cost to parent entity per facility (thousands)	$21.7 ($21.5–$21.8).
Mean number of facilities owned per parent	4.9 (4.4–5.4).
Mean cost to parent for all associated facilities (thousands)	$105.7 ($100.8–$110.7).
Mean parent entity revenue (billions)	$5.18 ($4.59–$5.77).
Total revenue for all subpart W parents (trillions)	$3.89 ($3.45–$4.33).
Mean CRR for parent entities, using all facility costs	0.60% (0.55–0.64%).

Note: Because parent revenues are heavily skewed towards higher revenues, the ratio of mean cost to mean revenue (which is approximately 0.002%) differs substantially from the mean cost-to-revenue ratio (which is approximately 0.60%).

The EPA has also considered the potential benefits of the proposed amendments to subpart W. Because this is a proposed reporting rule, the EPA did not quantify estimated emission reductions or monetize the benefits from such reductions that could be associated with this proposed action. The benefits of the proposed amendments are based on their relevance to policy making, transparency, and market efficiency. The proposed amendments to the reporting system for petroleum and natural gas systems would benefit policymakers and the public by increasing the completeness and accuracy of facility emissions data. Public data on emissions allows for accountability of emitters to the public. Improved facility-specific emissions data would aid local, state, and national policymakers as they evaluate and consider future climate change policy decisions and other policy decisions for criteria pollutants, ambient air quality standards, and toxic air emissions. The benefits of improved reporting of petroleum and natural gas systems GHG emissions to government also include enhancing existing programs, such as the Natural Gas STAR Program, that provide significant benefits, such as identifying cost-effective technologies and practices to reduce emissions of CH4 from operations in all of the major industry sectors—production, gathering and processing, transmission, and distribution. The Natural Gas STAR program leverages GHGRP reporting data to track partner petroleum and natural gas company activities related to their Methane Challenge commitments. The proposed changes to subpart W would increase knowledge of the location and magnitude of significant CH4 emissions sources in the petroleum and natural gas industry, and associated activities and technologies, which can result in improvements in technologies and the identification of new emissions reducing technologies.

Benefits to industry of improved GHG emissions monitoring and reporting under the proposed amendments include the value of having verifiable empirical 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. The EPA also anticipates that improvements to monitoring and implementation of empirical measurement methods would result in emissions reductions. Based on activity data used to inform the U.S. GHG Inventory, the EPA estimated approximately 403.4 billion cubic feet of fugitive CH4 emissions (including fugitive leaks, venting, and flaring) in 2021, representing a potential loss of over $871 million [134] to industry. To the extent that more frequent monitoring helps to identify and mitigate emissions from leakage, a robust reporting program based on empirical data can help industry and achieve and disseminate their environmental achievements. Businesses and other innovators can use the data to determine and track their GHG footprints, find cost-saving efficiencies that reduce GHG emissions and save product, and foster technologies to protect public health and the environment. to reduce costs associated with fugitive emissions. Such monitoring also allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to track actual company performance and to achieve and disseminate their environmental achievements. Once facilities invest in the institutional knowledge and systems to monitor and report emissions, the cost of monitoring should fall and the accuracy of the accounting should continue to improve. The proposed amendments would continue to allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry and achieve and disseminate information about their environmental performance.

In addition, transparent public data on emissions allows for accountability of polluters to the public who bear the cost of the pollution. The GHGRP serves as a powerful data resource and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. GHGRP data are easily accessible to the public via the EPA's online data publication tool, also known as FLIGHT (Facility Level Information on Greenhouse gases Tool) at: *https://ghgdata.epa.gov/ghgp/main.do*. FLIGHT is designed for the general public and allows users to view and sort GHG data from over 8,000 entities in a variety of ways including by location, industrial sector, and type of GHG emitted, and includes demographic data. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. Citizens, community groups, and labor unions have made use of public pollutant release data to negotiate directly with emitters to lower emissions, avoiding the need for additional regulatory action.

The proposed amendments would improve the quality and transparency of this reported data to affected communities, for example, by providing data on other large release events. The proposed disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to at least the well-pad and gathering boosting site-level, respectively, would provide communities with more localized information on GHG emissions from these segments. Therefore, while the EPA has not quantified the benefits of the proposed amendments to subpart W, the agency believes that they would be substantial and justify the estimated costs, if finalized as proposed. In

[134] Based on natural gas prices from EIA (current monthly average, April 2023). See *https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm*.

addition, the focus on empirical data that is the foundation of this proposed rule was mandated by Congress in the IRA.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a ''significant regulatory action'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. The EPA prepared an analysis of the potential impacts associated with this action. This analysis, *Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, is also available in the docket to this rulemaking and is briefly summarized in section VI of this preamble.

B. Paperwork Reduction Act

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned OMB No. 2060–NEW (EPA ICR number 2774.01). You can find a copy of the ICR in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234, and it is briefly summarized here.

The EPA estimates that the proposed amendments would result in an increase in burden. The burden associated with the proposed rule is due to revisions that would expand reporting to include new emission sources or that expand the industry segments covered by existing emissions sources and that may impact the facilities that are required to report to subpart W; revisions to emissions calculation methodologies that would require additional monitoring; and revisions to collect additional data to more accurately reflect and verify total CH_4 emissions in reports submitted to the GHGRP or to provide information for future implementation of the waste emissions charge under CAA section 136. As a result of these proposed revisions, 567 new sources are expected to become subject to subpart W. Labor and O&M costs are included for those new sources to comply with the reporting and recordkeeping costs detailed in EPA ICR No. 2300.18, as well as costs to comply with these proposed revisions.

The estimated annual average burden is 417,821 hours and $92.3 million over the 3 years covered by this information collection. Further information on the EPA's assessment on the impact on burden can be found in the memorandum, *Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

Respondents/affected entities: Owners and operators of petroleum and natural gas systems that must report their GHG emissions and other data to the EPA to comply with 40 CFR part 98.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA sections 114 and 136.

Estimated number of respondents: 3,077 (affected by proposed amendments).

Frequency of response: Annually.

Total estimated burden: 417,821 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $92.3 million, includes $50.9 million annualized capital or operation & maintenance costs.

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

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rulemaking. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than October 2, 2023. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed action would not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses in the petroleum and natural gas industry. Small entities include small businesses, small organizations, and small governmental jurisdictions. The EPA has determined that some small entities are affected because their production processes emit GHGs that must be reported.

In the implementation of the GHGRP, the EPA previously determined thresholds that reduced the number of small businesses reporting. The proposed revisions would not revise the threshold for existing subpart W reporters, therefore, we do not expect a significant number of small entities would be newly impacted under the proposed rule revisions.

The proposed rule amendments predominantly apply to existing reporters and are amendments that would expand reporting to include new emission sources; add, remove, or refine emissions estimation methodologies to improve the accuracy and transparency of reported emission data; for the Onshore Natural Gas Production and Onshore Natural Gas Gathering and Boosting segments, revise reporting of emissions from a basin level to a site level; implement requirements to collect new or revised data; clarify or update provisions that have been misinterpreted; or streamline or simplify requirements by increasing flexibility for reporters or removing redundant requirements.

The EPA conducted a small entity analysis that assessed the costs and impacts to small entities, including: (1) Revisions to add new emissions sources and expand the industry segments covered by existing emissions sources, (2) changes to improve existing monitoring or calculation methodologies, and (3) revisions to reporting and recordkeeping requirements for data provided to the program. The Agency anticipates that although a subset of small reporters (108–116) have a cost-to-revenue ratio (CRR) >1%, there are only a limited number (29–30) of very small entities (1–19 employees) that would be likely to have significant impacts with CRR >3%, reflecting only a small proportion of the affected small entities (2.0%–5.2%). The mean CRR for these very small entities (1–19 employees) is estimated to be between 1.55% (1.46–1.64%) and 2.06% (1.77–2.34%) based on the incremental costs for existing reporting entities and between 2.35% (2.16–2.55%) and 3.12% (2.59–3.66%) based on the costs for newly reporting entities.[135] Details of this analysis are

[135] The EPA conducted a multi-level analysis to estimate mean CRRs for multiple scenarios. The

presented in the memorandum, *Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234. Based on the results of this analysis, we have concluded that this proposed action is not likely to have a significant regulatory burden for a substantial number of directly regulated small entities and thus that this proposed action would not have a significant economic impact on a substantial number of small entities. The EPA continues to conduct significant outreach on the GHGRP and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries. We continue to be interested in the potential impacts of the proposed rule amendments on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action in part implements mandate(s) specifically and explicitly set forth in CAA section 136.

This proposed rule does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry that directly emits GHG above part 98 applicability threshold levels. It 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.

However, consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA sought comments from small governments concerning the regulatory requirements that might significantly or uniquely affect them in the development of this proposed rule. Specifically, the EPA previously published an RFI seeking public comment in a non-regulatory docket to collect responses to a range of questions related to the Methane Emissions Reduction Program, including subpart W revisions (see Docket Id. No. EPA–HQ–OAR–2022–0875). The EPA received two comments from government entities supporting the use of empirical data and improvements to the accuracy of calculation methods under subpart W; these comments were considered during the development of the proposed rule. The EPA continues to be interested in the potential impacts of the proposed rule amendments on state, local, or tribal governments and welcomes comments on issues related to such impacts.

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. This proposed rule does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry (*e.g.*, an LDC) that directly emits GHG above part 98 applicability threshold levels. Therefore, the EPA anticipates relatively few state or local government facilities would be affected. However, consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized Tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that may be owned by tribal governments that emit GHGs. However, it will generally only have tribal implications where the tribal entity owns a facility that directly emits GHGs above threshold levels; therefore, relatively few tribal facilities would be affected. Of the subpart W facilities currently reporting to the GHGRP in RY2021, we identified four facilities currently reporting to part 98 that are owned by one tribal parent company.

In addition to tribes that would be directly impacted by the proposed revisions due to owning a facility subject to the proposed requirements, the EPA anticipates that tribes could be impacted in cases where facilities subject to the proposed revisions are located on Tribal land. In particular, the EPA reviewed the location of the production wells reported by facilities under the Onshore Petroleum and Natural Gas Production segment and found production wells reported under subpart W on lands associated with approximately 20 tribes. Therefore, although the EPA anticipates that only one tribe would be subject to the rule, the EPA has sought opportunities to provide information to tribal governments and representatives during rule development. On November 4, 2022, the EPA published an RFI seeking public comment on a range of questions related to the Methane Emissions Reduction Program, including subpart W revisions (see Docket Id. No. EPA–HQ–OAR–2022–0875). The EPA received one comment from a tribal entity relevant to subpart W. The commenter supported the use of empirical data and improvements to the accuracy of calculation methods under subpart W, including the use of advanced CH_4 detection technologies for leak surveys at well sites and compressor stations; these comments were considered during the development of the proposed rule. Further, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will engage in consultation with Tribal officials during the development of this action.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The proposed amendments would expand reporting to include new emission sources; add, remove, or refine emissions estimation methodologies improve the accuracy and transparency of reported emission data; for the Onshore Natural Gas Production and Onshore Natural Gas Gathering and Boosting segments, revise reporting of

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mean CRR and associated 95-percent confidence intervals provide an estimate of the range of cost-to-sales ratios expected to apply to affected very small entities that would be expected in the total population.

emissions from a basin level to a site level; implement requirements to collect new or revised data; clarify or update provisions that have been misinterpreted; or streamline or simplify requirements by increasing flexibility for reporters or removing redundant requirements. We are also proposing revisions that streamline or simplify requirements or alleviate burden through revision, simplification, or removal of certain calculation, monitoring, recordkeeping, or reporting requirements. In general, these changes would not have a significant, adverse effect on the supply, distribution, or use of energy. In addition, the EPA is proposing confidentiality determinations for new and revised data elements proposed in this rulemaking and for certain existing data elements for which a confidentiality determination has not previously been proposed. These proposed amendments and confidentiality determinations do not make any changes to the existing monitoring, calculation, and reporting requirements under subpart W and are not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act and 1 CFR Part 51

This action involves technical standards. For facilities that conduct a performance test to calculate combustion slip, the EPA is proposing that the performance test would be conducted in accordance with one of the test methods in proposed 40 CFR 98.234(i), which include EPA Methods 18 and 320 as well as an alternate method, ASTM D6348–12. The EPA is proposing to allow the use of the alternate method ASTM D6348–12, which is based on the use of a Fourier transform infrared (FTIR) spectrometer for the identification and quantification of multicomponent gaseous compounds, in lieu of EPA Method 320. The EPA currently allows for the use of an earlier version of this method, ASTM D6348–03, under other subparts of part 98, including subparts I (Electronics Manufacturing), V (Nitric Acid Production), and OO (Fluorinated Gas Production), for the quantification of other GHGs. Therefore, the EPA is proposing to allow ASTM D6348–12 to be used in subpart W to quantify CH_4 emissions from combustion slip. Anyone may access the standards on the ASTM website (*https://www.astm.org/*) for additional information. These standards are available to everyone at a cost determined by the ASTM ($76). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available for reporters. The EPA will also make a copy of these documents available in hard copy at the appropriate EPA office (see the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information) for review purposes only.

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

The EPA anticipates that the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations as it does not directly affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

However, the data that would be collected through this action would provide an important data resource for communities and the public to understand GHG emissions. Since facilities would be required to use prescribed calculation and monitoring methods, emissions data can be compared and analyzed, including locations of emissions sources. GHGRP data are easily accessible to the public via the EPA's online data publication tool, also known as FLIGHT at: *https://ghgdata.epa.gov/ghgp/main.do*. FLIGHT is designed for the general public and allows users to view and sort GHG data for every reporting year starting with 2010 from over 8,000 entities in a variety of ways including by location, industrial sector, and type of GHG emitted. This powerful data resource provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments.

The proposed revisions to part 98 include requirements for reporting of GHG data from additional emission sources (other large release events, nitrogen removal units, produced water tanks, crankcase venting, and mud degassing), improvements to emissions calculation methodologies, and collection of data to support verification of GHG emissions and transparency. The proposed disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to at least the well-pad and gathering boosting site-level, respectively, and the required reporting of geographical coordinates for other large release events would provide communities with more localized information on GHG emissions from these segments.

Overall, these revisions would improve the quality of the data collected under the program and available to communities, if finalized.

K. Determination Under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determines that this action is subject to the provisions of CAA section 307(d). Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to ''such other actions as the Administrator may determine.''

List of Subjects in 40 CFR Part 98

Environmental protection, Greenhouse gases, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend title 40, chapter I, of the Code of Federal Regulations 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. 7401–7671q.

Subpart A—General Provision

■ 2. Amend § 98.1 by revising paragraph (c) to read as follows:

§ 98.1 Purpose and scope.

* * * * *

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms *Owner and Operator* used in this subpart have the same definition as *Onshore petroleum and natural gas production owner or operator*, as defined in § 98.238. For facilities required to report under onshore petroleum and natural gas gathering and boosting under subpart W of this part, the terms *Owner and Operator* used in this subpart have the same definition as *Gathering and boosting system owner or operator*, as defined in § 98.238. For facilities required to report under onshore natural gas transmission pipeline under subpart W of this part, the terms *Owner and*

Operator used in this subpart have the same definition as *Onshore natural gas transmission pipeline owner or operator*, as defined in § 98.238.

■ 3. Amend § 98.2 by revising paragraph (i)(3) to read as follows:

§ 98.2 Who must report?

* * * * *

(i) * * *

(3) If the operations of a facility or supplier are changed such that all applicable processes and operations subject to paragraphs (a)(1) through (4) of this section cease to operate, then the owner or operator may discontinue complying with this part for the reporting years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all applicable processes and operations no later than March 31 of the year following such changes. If one or more processes or operations subject to paragraphs (a)(1) through (4) of this section at a facility or supplier cease to operate, but not all applicable processes or operations cease to operate, then the owner or operator is exempt from reporting for any such processes or operations in the reporting years following the reporting year in which cessation of the process or operation occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting for the process or operation no later than March 31 following the first reporting year in which the process or operation has ceased for an entire reporting year. Cessation of operations in the context of underground coal mines includes, but is not limited to, abandoning and sealing the facility. This paragraph (i)(3) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(3) does not apply to the municipal solid waste landfills source category (subpart HH of this part), or the industrial waste landfills source category (subpart TT of this part). This paragraph (i)(3) does not apply when there is a change in the owner or operator for facilities in industry segments with a unique definition of facility as defined in § 98.238 of the petroleum and natural gas systems source category (subpart W of this part), unless the changes result in permanent cessation of all applicable processes and operations. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

* * * * *

■ 4. Amend § 98.4 by revising the first sentence of paragraph (h) and adding paragraph (n) to read as follows:

§ 98.4 Authorization and responsibilities of the designated representative.

* * * * *

(h) *Changes in owners and operators.* Except as provided in paragraph (n) of this section, in the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. * * *

* * * * *

(n) Alternative provisions for changes in owners and operators for industry segments with a unique definition of facility as defined in § 98.238. When there is a change to the owner or operator of a facility required to report under the onshore petroleum and natural gas production, natural gas distribution, onshore petroleum and natural gas gathering and boosting, or onshore natural gas transmission pipeline industry segments of subpart W of this part, or a change to the owner or operator for some emission sources from the facility in one of these industry segments, the provisions specified in paragraphs (n)(1) through (4) of this section apply for the respective type of change in owner or operator. The provisions specified in paragraph (n)(5) of this section apply to the types of change in owner or operator specified in paragraphs (n)(3) and (4) of this section.

(1) If the entire facility is acquired by an owner or operator that does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), then within 90 days after the change in the owner or operator, the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section. If the new owner or operator already had emission sources specified in § 98.232(c), (i), (j) or (m), as applicable, prior to the acquisition in the same basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution) as the acquired facility but had not previously met the applicability requirements in §§ 98.2(a) and 98.231, then per the applicable definition of facility in § 98.238, the previously owned applicable emission sources must be included in the acquired facility. The new owner or operator and the new designated representative shall be responsible for submitting the annual report for the facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new owner or operator and the new designated representative shall also be responsible for submitting any required annual GHG report revisions required by § 98.3(h) for reporting years prior to the reporting year in which the acquisition occurred.

(2) If the entire facility is acquired by an owner or operator that already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the new owner or operator shall merge the acquired facility with their existing facility for purposes of the annual GHG report. Within 90 days after the change in the owner or operator, the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section to reflect the new owner or operator for the acquired facility. The owner or operator shall also follow the provisions of § 98.2(i)(6) to notify EPA that the acquired facility will discontinue reporting and shall provide the e-GGRT identification number of the merged, or reconstituted, facility. The owner or operator of the merged facility shall be responsible for submitting the annual report for the merged facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new owner or operator and the new designated representative shall also be responsible for submitting any required annual GHG report revisions required by § 98.3(h) for reporting years prior to the reporting year in which the acquisition occurred.

(3) If only some emission sources from the facility are acquired by one or more new owners or operators, the existing owner or operator (*i.e.*, the owner or operator of the portion of the facility that is not sold) shall continue to report under subpart W of this part for the retained emission sources unless

and until that facility meets one of the criteria in § 98.2(i). Each owner or operator that acquires emission sources from the facility must account for those acquired emission sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(i) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the purchasing owner or operator shall begin reporting as a new facility. The new facility must include the acquired emission sources specified in § 98.232(c), (i), (j), or (m), as applicable, and any emission sources the purchasing owner or operator already owned in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution). The designated representative for the new facility must be selected by the purchasing owner or operator according to the schedule and procedure specified in paragraphs (b) through (d) of this section. The purchasing owner or operator shall be responsible for submitting the annual report for the new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The purchasing owner or operator shall continue to report under subpart W of this part for the new facility unless and until that facility meets one of the criteria in § 98.2(i).

(ii) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), then per the applicable definition of facility in § 98.238, the purchasing owner or operator must add the acquired emission sources specified in § 98.232(c), (i), (j), or (m), as applicable, to their existing facility for purposes of reporting under subpart W. The purchasing owner or operator shall be responsible for submitting the annual report for the entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(4) If all the emission sources from a reporting facility are sold to multiple owners or operators within the same reporting year, such that the current owner or operator of the existing facility does not retain any of the emission sources, then the current owner or operator of the existing facility shall notify EPA within 90 days of the last transaction that all of the facility's emission sources were acquired by multiple purchasers, including the identity of the purchasers. Each owner or operator that acquires emission sources from a facility shall account for those sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(5) Within 90 days of a transaction that results in a change to the owner or operator of a facility as described in paragraph (n)(3) or (4) of this section, the owners or operators involved in that transaction shall select a historic reporting representative who will be responsible for revisions to annual GHG reports under § 98.3(h) for reporting years prior to the reporting year in which the transaction occurred. The historic reporting representative shall be an individual selected by an agreement binding on each of the owners and operators involved in the transaction, following the provisions of paragraph (b) of this section. The provisions of paragraphs (b), (c), (e), and (g) of this section apply to the historic reporting representative by substituting the term ''historic reporting representative'' for ''designated representative.'' The provisions of paragraph (i) of this section apply to the historic reporting representative by adding the term ''historic reporting representative'' to instances of ''the designated representative and any alternate designated representative.''

■ 5. Amend § 98.6 by revising the definitions for ''Dehydrator'', ''Dehydrator vent emissions'', ''Desiccant'', and ''Vapor recovery system'' to read as follows:

§ 98.6 Definitions.

* * * * *

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

Dehydrator vent emissions means natural gas and CO2 released from a natural gas dehydrator system absorbent (typically glycol) regenerator still vent and, if present, a flash tank separator, to the atmosphere, flare, regenerator fire-box/fire tubes, or vapor recovery system. Emissions include stripping natural gas and motive natural gas used in absorbent circulation pumps.

* * * * *

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include, but are not limited to, molecular sieves, activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

* * * * *

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. For purposes of § 98.233, routing emissions from a dehydrator regenerator still vent or flash tank separator vent to a regenerator fire-box/fire tubes does not meet the definition of vapor recovery system.

* * * * *

■ 6. Amend § 98.7 by adding paragraph (e)(53) to read as follows:

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

* * * * *

(e) * * *

(53) ASTM D6348–12 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for § 98.234(j).

* * * * *

Subpart C—General Stationary Fuel Combustion Sources

■ 7. Amend § 98.33 by revising parameter ''EF'' of Equation C–8 in paragraph (c)(1) introductory text, Equation C–8a in paragraph (c)(1)(i), Equation C–8b in paragraph (c)(1)(ii), Equation C–9a in paragraph (c)(2), and Equation C–10 in paragraph (c)(4) introductory text to read as follows:

§ 98.33 Calculating GHG emissions.

* * * * *

(c) * * *

(1) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(i) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(ii) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(2) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(4) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

■ 8. Amend § 98.36 by adding paragraphs (b)(13), (c)(1)(xiii), and (c)(3)(xiii) to read as follows:

§ 98.36 Data reporting requirements.

* * * * *

(b) * * *

(13) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must also report:

(i) Type of equipment: two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, or gas turbine.

(ii) Method by which the CH_4 emission factor was determined: performance test, manufacturer data, or default emission factor.

(iii) Value of the CH_4 emission factor.

(c) * * *

(1) * * *

(xiii) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must report the equipment type (*i.e.,* two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, and gas turbine), the method by which the CH_4 emission factor was determined (*i.e.,* performance test, manufacturer data, or default emission factor), and the average value of the CH_4 emission factor.

* * * * *

(3) * * *

(xiii) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must report the equipment type (*i.e.,* two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, and gas turbine) the method by which the CH_4 emission factor was determined (*i.e.,* performance test, manufacturer data, or default emission factor), and the average value of the CH_4 emission factor.

* * * * *

■ 9. Amend table C–2 to subpart C of part 98 by revising the entry "Natural Gas" to read as follows:

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
* *	*	* *
Natural Gas [1]	1.0×10^{-03}	1.0×10^{-04}.
* *	*	* *

* * * * *

[1] Reporters subject to subpart W of this part may only use the default CH_4 emission factor for natural gas-fired combustion units that are not reciprocating internal combustion engines or gas turbines. For natural gas-fired reciprocating internal combustion engines or gas turbines, at facilities subject to subpart W of this part, reporters must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

Subpart W—Petroleum and Natural Gas Systems

■ 10. Amend § 98.230 by revising paragraphs (a)(2), (3) and (9) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well-pad using CO_2 or natural gas injection.

(3) *Onshore natural gas processing.* Onshore natural gas processing means the forced extraction of natural gas

liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. Natural gas processing does not include a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

* * * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

* * * * *

■ 11. Amend § 98.232 by:

■ a. Revising paragraphs (a), (b) and (c)(2), (10), (17), and (21);

■ b. Adding paragraphs (c)(23) through (25);

■ c. Revising paragraphs (d)(5) and (7);

■ d. Adding paragraphs (d)(8) through (11);

■ e. Revising paragraphs (e)(3) and (8);

■ f. Adding paragraphs (e)(9) through (11);

■ g. Revising paragraphs (f)(6) and (8);

■ h. Adding paragraphs (f)(9) through (13);

■ i. Revising paragraphs (g)(6) and (7);

■ j. Adding paragraphs (g)(8) through (11);

■ k. Revising paragraphs (h)(7) and (8);

■ l. Adding paragraphs (h)(9) through (11) and (i)(8) through (11);

■ m. Revising paragraphs (j)(3), (6), and (10);

■ n. Adding paragraphs (j)(13) and (14);

■ o. Revising paragraph (m); and

■ p. Adding paragraph (n).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

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

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified by Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR 550.302 through 304 and CO_2 and CH_4 emissions from other large release events. Offshore platforms do not need to report portable emissions.

(c) * * *

(2) Blowdown vent stacks.

* * * * *

(10) Hydrocarbon liquids and produced water storage tank emissions.

* * * * *

(17) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(21) Equipment leaks listed in paragraph (c)(21)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, dehydrators, heaters, and storage vessels.

* * * * *

(23) Other large release events.

(24) Drilling mud degassing.

(25) Crankcase vents.

(d) * * *

(5) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service (not including thief hatches or other openings on storage vessels) that either are subject to equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Natural gas pneumatic device venting.

(9) Other large release events.

(10) Hydrocarbon liquids and produced water storage tank emissions.

(11) Crankcase vents.

(e) * * *

(3) Condensate storage tanks.

* * * * *

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel.

(9) Other large release events.

(10) Dehydrator vents.

(11) Crankcase vents.

(f) * * *

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (f)(6) do not include thief hatches or other openings on a storage vessel.

* * * * *

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or

an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Other large release events.

(10) Dehydrator vents.

(11) Blowdown vent stacks.

(12) Condensate storage tanks.

(13) Crankcase vents.

(g) * * *

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Other large release events.

(9) Blowdown vent stacks.

(10) Acid gas removal unit vents and nitrogen removal unit vents.

(11) Crankcase vents.

(h) * * *

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Acid gas removal unit vents and nitrogen removal unit vents.

(10) Other large release events.

(11) Crankcase vents.

(i) * * *

(8) Other large release events.

(9) Blowdown vent stacks.

(10) Natural gas pneumatic device venting.

(11) Crankcase vents.

(j) * * *

(3) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(6) Hydrocarbon liquids and produced water storage tank emissions.

* * * * *

(10) Equipment leaks listed in paragraph (j)(10)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, dehydrators, heaters, and storage vessels.

* * * * *

(13) Other large release events.

(14) Crankcase vents.

* * * * *

(m) For onshore natural gas transmission pipeline, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Blowdown vent stacks.

(2) Other large release events.

(3) Equipment leaks at transmission company interconnect metering-regulating stations.

(4) Equipment leaks at farm tap and/or direct sale metering-regulating stations.

(5) Transmission pipeline equipment leaks.

(n) For all facilities meeting the applicability provisions under § 98.2 and, if applicable, § 98.231, report the information required under subpart B of this part (Metered, Non-fuel, Purchased Energy Consumption by Stationary Sources).

■ 12. Amend § 98.233 by:

■ a. Revising paragraphs (a), (c), (d), (e) introductory text, (e)(1) introductory text, (e)(1)(i), (ii), (x), and (xi), and (e)(2) introductory text;

■ b. Revising parameter ''Count'' of Equation W–5 in paragraph (e)(2);

■ c. Revising paragraph (e)(3) introductory text;

■ d. Removing paragraph (e)(4);

■ e. Redesignating paragraphs (e)(5) and (6) as (e)(4) and (5), respectively;

■ f. Revising newly redesignated paragraphs (e)(4) and (5) and paragraphs (f), (g) introductory text, and (g)(1) introductory text;

■ g. Removing and reserving paragraph (g)(1)(ii);

■ h. Revising parameter ''$FR_{s,p}$'' and ''N'' of Equation W–12A in paragraph (g)(1)(iii);

■ i. Revising parameters ''$FR_{i,p}$'' and ''N'' of Equation W–12B in paragraph (g)(1)(iv);

■ j. Removing paragraph (g)(4);

■ k. Revising paragraph (h) introductory text;

■ l. Removing and reserving paragraph (h)(2);

■ m. Revising paragraph (i)(2) introductory text;

■ n. Revising parameters ''T_a'' and ''P_a'' of Equation W–14A in paragraph (i)(2)(i);

■ o. Revising parameters ''$T_{a,p}$'', ''$P_{a,b,p}$'', and ''$P_{a,e,p}$'' of Equation W–14B in paragraph (i)(2)(i);

■ p. Adding paragraph (i)(2)(iv);

■ q. Revising paragraphs (j) and (k) introductory text,

■ r. Removing paragraph (k)(5);

■ s. Revising paragraphs (l) introductory text and (l)(3);

■ t. Removing paragraph (l)(6);

■ u. Revising paragraphs (m) introductory text and (m)(3);

■ v. Removing paragraph (m)(5);

■ w. Revising paragraphs (n), (o) introductory text, (o)(1)(i) introductory text, (o)(1)(i)(A) through (C), (o)(2) introductory text, (o)(2)(i) introductory text, and (o)(2)(ii);

■ x. Adding paragraph (o)(2)(iii);

■ y. Removing and reserving paragraph (o)(4)(ii)(D);

■ z. Revising paragraphs (o)(4)(ii)(E) and (o)(6)(i) introductory text;

■ aa. Revising parameter ''m'' of Equation W–21 in paragraph (o)(6)(i);

■ bb. Revising paragraph (o)(6)(ii) introductory text;

■ cc. Revising parameter ''m'' of Equation W–22 in paragraph (o)(6)(ii);

■ dd. Revising paragraph (o)(6)(iii) introductory text;

■ ee. Revising parameter "m" of Equation W–23 in paragraph (o)(6)(iii);
■ ff. Revising parameter "T_g" of Equation W–24B in paragraph (o)(8);
■ gg. Revising paragraph (o)(10);
■ hh. Removing paragraph (o)(12);
■ ii. Revising paragraphs (p) introductory text, (p)(1)(i), (p)(2) introductory text, (p)(2)(ii) introductory text, (p)(2)(ii)(C), (p)(2)(iii)(A), and (p)(4)(ii)(C);
■ jj. Removing and reserving paragraph (p)(4)(ii)(D);
■ kk. Revising paragraphs (p)(4)(ii)(E), (p)(6)(ii) introductory text, and (p)(6)(iii) introductory text,
■ ll. Revising parameter "T_g" of Equation W–29B in paragraph (p)(8);
■ mm. Revising paragraph (p)(10);
■ nn. Removing paragraph (p)(12);
■ oo. Revising paragraphs (q) introductory text, (q)(1), (q)(2) introductory text, (q)(2)(i), and (q)(2)(iii) through (xi);
■ pp. Adding paragraphs (q)(3) and (4);
■ qq. Revising paragraphs (r) and (s);
■ rr. In paragraph (t)(2), revising parameter "Z_a" of Equation W–34, and removing the undesignated paragraph following the parameters of Equation W–34;
■ ss. Revising paragraphs (u)(2)(ii), (y), and (z);
■ tt. Adding and reserving paragraphs (aa) through (cc); and
■ uu. Adding paragraphs (dd) and (ee).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) *Natural gas pneumatic device venting.* For all natural gas pneumatic devices at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities, use the applicable provisions as specified in this paragraph (a) of this section to calculate CH_4 and CO_2 emissions from natural gas pneumatic device venting. If you have a flow meter on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices or natural gas driven pneumatic pumps vented directly to the atmosphere for any portion of the year, you must use the method specified in paragraph (a)(1) of this section to calculate CH_4 and CO_2 emissions from those devices. For natural gas pneumatic devices vented directly to the atmosphere for which the natural gas supply rate is not measured, use the applicable methods specified in paragraphs (a)(2) through (6) of this section to calculate CH_4 and CO_2 emissions. For natural gas pneumatic devices that are routed to flares, combustion, or vapor recovery systems, use the applicable provisions specified in paragraphs (a)(7) of this section.

(1) *Calculation Method 1.* If you have or elect to install a flow meter on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices and natural gas driven pneumatic pumps that are vented directly to the atmosphere, you must use the applicable methods specified in paragraph (a)(1)(i) through (iv) of this section to calculate CH_4 and CO_2 emissions from those devices.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are routed to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual volumetric flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, escalate the measured volumetric flow by the ratio of the total hours for which natural gas was supplied to the devices to the number of hours the natural gas supplied to the devices was measured.

(B) Convert the natural gas volumetric flow from paragraph (a)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (a)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are vented directly to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual mass flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, escalate the measured mass flow by the ratio of the total hours for which natural gas was supplied to the devices to the number of hours the natural gas supplied to the devices was measured.

(B) Convert the cumulative mass flow from paragraph (a)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the flow meter on the natural gas supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraphs (a)(1) and (3) of this section, you must measure the volumetric flow rate of each natural gas pneumatic device vent that vents directly to the atmosphere at your facility as specified in paragraphs (a)(2)(i) through (ix) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be measured or for which emissions are calculated according to the requirements in this paragraph (a)(2).

(i) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you must measure all natural gas pneumatic devices at your facility at least once every 5 years. If you elect to measure your pneumatic devices over multiple years, you must measure approximately the same number of devices each year. When you measure the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must measure all natural gas pneumatic devices that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year.

(ii) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments, you must either measure all natural gas pneumatic devices vented directly to the atmosphere at your facility each year if your facility has less than 26 pneumatic devices or over multiple years not to exceed the number of years as specified in paragraphs (a)(2)(ii)(A) through (D) of this section. If you elect to measure your pneumatic devices over multiple years, you must measure approximately the same number of devices each year.

(A) If your facility has at least 26 but not more than 50 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 2 years.

(B) If your facility has at least 51 but not more than 75 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 3 years.

(C) If your facility has at least 76 but not more than 100 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 4 years.

(D) If your facility has 101 or more natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 5 years.

(iii) For all industry segments, determine the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (a)(2)(iii)(A) through (D) of this section.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth § 98.234(d), you must measure the emissions from each device for a minimum of 15 minutes while the device is in service (*i.e.,* supplied with natural gas), except for natural gas pneumatic isolation valve actuators. For natural gas pneumatic isolation valve actuators, you must measure the emissions from each device for a minimum of 5 minutes while the device is in service (*i.e.,* supplied with natural gas). If there is no measurable flow from the natural gas pneumatic device after the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c) except you need only fill one bag to have a valid measurement. You must collect sample for a minimum of 5 minutes for natural gas pneumatic isolation valve actuators or 15 minutes for other natural gas pneumatic devices. If no gas is collected in the calibrated bag during the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section. If gas is collected in the bag during the minimum sampling period, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (a)(2)(iii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas pneumatic device vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section.

(iv) For all industry segments, if there is measurable flow from the device vent, calculate the volume of natural gas emitted from each natural gas pneumatic device vent as the product of the natural gas flow rate measured in paragraph (a)(2)(iii) of this section and the number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(v) For all industry segments, if there is no measurable flow from the device vent, estimate the emissions from the device according to the methods in paragraphs (a)(2)(v)(A) through (C) of this section, as applicable.

(A) For continuous high bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service.

(*2*) Confirm that the device is correctly characterized as a continuous high bleed pneumatic device according to the provisions in paragraph (a)(6) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraphs (a)(2)(v)(B) or (C) of this section, as applicable.

(*3*) Upon confirmation of the items in paragraphs (a)(2)(v)(A)(*1*) and (2) of this section, remeasure the device vent using a different measurement method or longer monitoring duration until the volumetric venting rate can be accurately quantified.

(B) For continuous low bleed pneumatic devices:

(1) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service.

(2) Determine natural gas bleed rate (in standard cubic feet per hour) at the supply pressure used for the pneumatic device based on the manufacturer's steady state natural gas bleed rate reported for the device. If the steady state bleed rate is reported in terms of air consumption, multiply the air consumption rate by 1.29 to calculate the steady state natural gas bleed rate. If a steady state bleed rate is not reported, you need to reassess whether the device is correctly characterized as a continuous low bleed pneumatic device according to the provisions in paragraph (a)(6) of this section.

(3) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the natural gas steady state bleed rate determined in paragraph (a)(2)(v)(B)(2) of this section and number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(C) For intermittent bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions according to paragraph (a)(2)(iv) of this section. For devices confirmed to be in-service during the measurement period, calculate natural gas emissions according to paragraph (a)(2)(v)(C)(*2*) through (*5*) of this section.

(*2*) Calculate the volume of the controller, tubing and actuator (in actual cubic feet) based on the device and tubing size.

(*3*) Sum the volumes in paragraph (a)(2)(v)(C)(*2*) of this section and convert the volume to standard cubic feet following the methods specified in paragraph (t)(1) of this section based on the natural gas supply pressure.

(*4*) Estimate the number of actuations during the year based on company records, if available, or best engineering estimates. For isolation valve actuators, you may multiply the number of valve closures during the year by 2 (one actuation to close the valve; one actuation to open the valve).

(*5*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the per actuation volume in standard cubic feet determined in paragraph (a)(2)(v)(C)(*3*) of this section, the number of actuations during the year as determined in paragraph (a)(2)(v)(C)(*4*) of this section, and the relay correction factor. Use 1 for the relay correction factor if there is no relay; use 3 for the relay correction factor if there is a relay.

(*6*) Calculate the hourly average volume of natural gas emitted from the natural gas pneumatic device vent by dividing the volume of natural gas emitted as determined in paragraph (a)(2)(v)(C)(*5*) of this section by the number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(vi) For each pneumatic device, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (a)(2)(iv) or (v) of this section, as applicable, to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(vii) For each pneumatic device, convert the GHG volumetric emissions at standard conditions determined in paragraph (a)(2)(vi) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(viii) Sum the CO_2 and CH_4 mass emissions determined in paragraph (a)(2)(vii) of this section separately for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(ix) If you chose to conduct natural gas pneumatic device measurements over multiple years, ''n,'' according to paragraph (a)(2)(i) or (ii) of this section, then you must calculate the emissions from all pneumatic devices at your facility as specified in paragraph (a)(2)(ix)(A) through (D) of this section.

(A) Use the emissions calculated in (a)(2)(viii) of this section for the devices measured during the reporting year.

(B) Calculate the whole gas emission factor for each type of pneumatic device at the facility using Equation W–1A and all available data from the current year and the previous years in your monitoring cycle (n–1 years) for which natural gas pneumatic device vent measurements were made according to Calculation Method 2 in paragraph (a)(2) of this section (*e.g.,* if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_t = \frac{\sum_{y=1}^{n} MT_{s,t,y}}{\sum_{y=1}^{n} Count_{t,y}} \qquad \text{(Eq. W-1A)}$$

Where:

EF_t = Whole gas population emission factor for natural gas pneumatic device vents of type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed), in standard cubic feet per hour per device.

$MT_{s,t,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions from component type ''t'' during year ''y'' in standard cubic feet per hour, as calculated in paragraph (a)(2)(iii) [if there was measurable flow from the device vent], (a)(2)(v)(B)(*2*), or (a)(2)(v)(C)(*6*) of this section, as applicable.

$Count_{t,y}$ = Count of natural gas pneumatic device vents of type ''t'' measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic device vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices that were not measured during the reporting year using Equation W–1B of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1B)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types ''t'' (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraphs (a)(4) through (6) of this section that vent directly to the atmosphere and that were not directly measured according to the requirements in paragraph (a)(1) or (a)(2)(iii) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed) as calculated using Equation W–1A of this section.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas processing, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraph (u)(2) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type ''t'', were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(D) Convert the volumetric emissions calculated using Equation W–1B to CH_4 and CO_2 mass emissions using the methods specified in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (a)(2)(ix)(A) and (D) of this section separately for each type of pneumatic device (continuous high bleed, continuous low bleed, intermittent bleed) to calculate the total CH_4 and CO_2 mass emissions by device type for Calculation Method 2.

(3) *Calculation Method 3.* As an alternative to Calculation Method 2, you may elect to use the applicable methods specified in paragraphs (a)(3)(i) through (v) of this section, as applicable, to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your facility except those that are measured according to paragraph (a)(1) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(3).

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere, you must calculate CH_4 and CO_2 volumetric emissions using either the methods in paragraph (a)(3)(i)(A) or (B) of this section.

(A) Measure all continuous high bleed and continuous low bleed pneumatic devices at your well-pad, gathering and boosting site, or facility, as applicable, according to the provisions in paragraphs (a)(2) of this section.

(B) Use Equation W–1B, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' (continuous high bleed and continuous low bleed) as listed in table W–1 to this subpart.

(ii) For intermittent bleed pneumatic devices, you must monitor each intermittent bleed pneumatic device at your facility using the methods specified in paragraph (a)(3)(ii)(A) of this section at the frequency specified in paragraph (a)(3)(ii)(B) or (C) of this section, as applicable.

(A) You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device.

(B) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you must monitor all natural gas intermittent bleed pneumatic devices at your facility at least once every 5 years. If you elect to monitor your pneumatic devices over multiple years, you must monitor approximately the same number of devices each year. When you monitor the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year.

(C) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments you must either monitor all natural gas intermittent bleed pneumatic devices vented directly to the atmosphere at your facility each year if your facility has less than 101 intermittent bleed pneumatic devices or over multiple years not to exceed the number of years as specified in paragraphs (a)(3)(ii)(C)(1) through (*4*) of this section. If you elect to monitor your intermittent bleed pneumatic devices over multiple years, you must monitor approximately the same number of devices each year.

(*1*) If your facility has at least 101 but not more than 200 natural gas intermittent bleed pneumatic devices vented directly to the atmosphere, the maximum number of years to monitor all devices at your facility is 2 years.

(*2*) If your facility has at least 201 but not more than 300 natural gas intermittent bleed pneumatic devices vented directly to the atmosphere, the maximum number of years to monitor all devices at your facility is 3 years.

(*3*) If your facility has at least 301 but not more than 400 natural gas intermittent bleed pneumatic devices vented directly to the atmosphere, the maximum number of years to monitor all devices at your facility is 4 years.

(*4*) If your facility has 401 or more natural gas intermittent bleed pneumatic devices vented directly to the atmosphere, the maximum number of years to monitor all devices at your facility is 5 years.

(iii) For intermittent bleed pneumatic devices that are monitored according to paragraph (a)(3)(ii)(A) of this section during the reporting year, you must calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere using Equation W–1C of this section.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x} \left\{ 16.1 \times T_{mal,z} + 2.82 \times \left(T_{t,z} - T_{mal,z} \right) \right\} + \left(2.82 \times Count \times T_{avg} \right) \right] \quad \text{(Eq. W-1C)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from intermittent bleed natural gas pneumatic devices in standard cubic feet.

GHG_i = Concentration of GHGi, CH_4, or CO_2, in natural gas supplied to the intermittent bleed natural gas pneumatic device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the year. A component found as malfunctioning in two or more surveys during the year is counted as one malfunctioning component.

16.1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

$T_{mal,z}$ = The total time the surveyed pneumatic device ''z'' was in service (*i.e.*, supplied with natural gas) and assumed to be malfunctioning, in hours. If one pneumatic device monitoring survey is conducted in the calendar year, assume the device found malfunctioning was malfunctioning for the entire calendar year. If multiple pneumatic device monitoring surveys are conducted in the calendar year, assume a device found malfunctioning in the first survey was malfunctioning since the beginning of the year until the date of the survey; assume a device found malfunctioning in the last survey of the year was malfunctioning from the preceding survey through the end of the year; assume a device found malfunctioning in a survey between the first and last surveys of the year was malfunctioning since the preceding survey until the date of the survey; and sum times for all malfunctioning periods.

$T_{t,z}$ = The total time the surveyed natural gas pneumatic device ''z'' was in service (i.e., supplied with natural gas) during the year. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

2.82 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

Count = Total number of intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey during the year.

T_{avg} = The average time the intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

(A) You must conduct at least one complete pneumatic device monitoring survey in a calendar year. If you conduct multiple complete pneumatic device monitoring surveys in a calendar year, you must use the results from each complete pneumatic device monitoring survey when calculating emissions using Equation W–1C.

(B) For the purposes of paragraph (a)(3)(iii)(A) of this section, a complete monitoring survey is a survey of all intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at a well-pad for onshore petroleum and natural gas production facilities, all intermittent bleed pneumatic devices vented directly to the atmosphere at a gathering and boosting site for onshore petroleum and natural gas gathering and boosting facilities, or all intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at a facility required to be monitored during a given year for other applicable industry segments.

(iv) For intermittent bleed natural gas pneumatic devices that are not monitored according to paragraph (a)(3)(ii)(A) of this section during the reporting you, you must calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere as specified in paragraphs (a)(3)(iv)(A) through (D) of this section.

(A) Count the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere that were monitored during the reporting year. If you conducted multiple monitoring surveys, count each device only once; do not count the same device twice if it was monitored two times during the reporting year.

(B) Count the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere that were monitored during the reporting year that were identified as malfunctioning during the reporting year. If you conducted multiple monitoring surveys, count each device only once; do not count the same device twice if it was monitored and identified as malfunctioning two separate times during the reporting. If a device was malfunctioning during one monitoring survey and not during a second, count that device as a device that was identified as malfunctioning during the reporting year.

(C) Determine the number of intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at your facility that were not monitored during the reporting year as the difference between the total count of devices at your facility as determined according to paragraphs (a)(4) through (6) of this section and the count of unique devices monitored during the reporting year as determined in paragraph (a)(3)(vi)(A) of this section.

(D) Calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere that were not monitored during the reporting year using Equation W–1D of this section.

$$E_i = GHG_i \times T_{avg} \times Count_C \times \left[16.1\times\left(\frac{Count_B}{Count_A}\right) + 2.82\times\left(1-\frac{Count_B}{Count_A}\right)\right] \qquad \text{(Eq. W-1D)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from intermittent bleed natural gas pneumatic devices in standard cubic feet.

GHGi = Concentration of GHGi, CH_4 or CO_2, in natural gas supplied to the intermittent bleed device as defined in paragraph (u)(2) of this section.

T_{avg} = The average time the intermittent bleed natural gas pneumatic devices that were not surveyed during the year were in service (*i.e.*, supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

$Count_C$ = Total number of intermittent bleed pneumatic devices that were not surveyed during the year as determined according to paragraph (a)(3)(iv)(C) of this section.

16.1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

$Count_B$ = Total number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere that were monitored during the reporting year that were identified as malfunctioning during the reporting year as determined according to paragraph (a)(3)(iv)(B) of this section.

$Count_A$ = Total number the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere that were monitored during the reporting year as determined according to paragraph (a)(3)(iv)(A) of this section.

2.82 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

(v) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(3)(i), (iii) and (iv) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(4) *Counts of natural gas pneumatic devices.* For all industry segments, determine ''Countt'' for Equation W–1A, W–1B, or W–1C of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the total number of devices at the facility, the number of devices that are vented directly to the atmosphere and the number of those devices that were measured or monitored during the reporting year, as applicable, except as specified in paragraph (a)(5) of this section.

(5) *Counts of onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting natural gas pneumatic devices.* For facilities in the onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine the total number of natural gas pneumatic devices at the facility and the number of devices that are vented directly to the atmosphere for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed), as applicable, using engineering estimates based on best available data. Counts of natural gas pneumatic devices measured or monitored during the reporting year must be made based on actual counts.

(6) *Type of natural gas pneumatic devices.* For all industry segments, determine the type of natural gas pneumatic device using engineering estimates based on best available information.

(7) *Routing to flares, combustion, or vapor recovery systems.* Calculate emissions from natural gas pneumatic devices routed to flares, combustion, or vapor recovery systems as specified in paragraph (a)(7)(i) or (ii) of this section, as applicable. If a device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then calculate emissions from the time the device vents directly to the atmosphere as specified in paragraph (a)(1), (2) or (3) of this section, as applicable, and calculate emissions from the time the device was routed to a flare or combustion as specified in paragraph (a)(7)(i) or (ii) of this section, as applicable. During periods when natural

gas pneumatic device emissions are collected in a vapor recovery system that is not routed to combustion, paragraphs (a)(1) through (3) and (a)(7)(i) and (ii) of this section do not apply and no emissions calculations are required.

(i) If any natural gas pneumatic devices were routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(ii) If emissions from any natural gas pneumatic devices were routed to combustion units, you must calculate and report emissions as specified in subpart C of this part or calculate emissions as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z), as applicable.

* * * * *

(c) *Natural gas driven pneumatic pump venting.* Calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraph (c)(1), (2), or (3) of this section, as applicable. If you have a flow meter on the natural gas supply line that is dedicated to any one or more natural gas driven pneumatic pumps, each of which only vents directly to the atmosphere, you must use Calculation Method 1 as specified in paragraph (c)(1) of this section to calculate vented CH_4 and CO_2 emissions from those pumps. Use Calculation Method 1 for any portion of a year when all of the pumps on the measured natural gas supply line were vented directly to atmosphere. For natural gas driven pneumatic pumps vented directly to the atmosphere for which the natural gas supply rate is not measured, use either the method specified in paragraph (c)(2) or (3) of this section to calculate vented CH_4 and CO_2 emissions for all of the natural gas driven pneumatic pumps at your facility that are not subject to Calculation Method 1; you may not use Calculation Method 2 for some vented natural gas driven pneumatic pumps and Calculation Method 3 for other natural gas driven pneumatic pumps. Similarly, if a flow meter is on a natural gas supply line that supplies some pumps that vent directly to the atmosphere and others that route emissions to flares, combustion, or vapor recovery systems, then use either the method specified in paragraph (c)(2) or (3) of this section to calculate vented CH_4 and CO_2 emissions because Calculation Method 1 may not be used for this natural gas supply line. Calculate emissions from natural gas driven pneumatic pumps routed to flares or combustion as specified in paragraph (c)(4) of this section. If a pump vents directly to the atmosphere for part of the year and to a flare or combustion unit for another part of the year, then calculate vented emissions for the portion of the year when venting occurs using the applicable method in paragraph (c)(1), (2), or (3) of this section for the period when venting occurs, and calculate emissions for the portion of the year when the emissions are routed to a flare or combustion unit using the method in paragraph (c)(4) of this section. No emissions calculation is required during periods when emissions from a pump are routed to a vapor recovery system without subsequently being routed to combustion. All references to natural gas driven pneumatic pumps for Calculation Method 1 in this paragraph (c) also apply to combinations of pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line; when the supply line serves both pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

(1) *Calculation Method 1.* If you have or elect to install a flow meter on a supply line to natural gas driven pneumatic pumps, then for the period of the year when the natural gas supply line is dedicated to any one or more natural gas driven pneumatic pumps, and the pumps are vented directly to the atmosphere, you must use the applicable methods specified in paragraphs (c)(1)(i) or (ii) of this section to calculate vented CH_4 and CO_2 emissions from those pumps.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total annual volume of natural gas used in the pumps that are connected to the measured supply line by escalating the measured volumetric flow by the ratio of the total hours for which natural gas was supplied to the pumps to the number of hours the natural gas supplied to the pumps was measured as specified in Equation W–2A of this section.

$$E_s = E_{s,M} \times \frac{T}{T_M} \quad \text{(Eq. W-2A)}$$

Where:

E_s = Annual natural gas emissions for pumps connected to natural gas supply line that had a natural gas flow meter installed during the year, in standard cubic feet.

$E_{s,M}$ = Measured volume of natural gas in the supply line, from the time that the natural gas flow meter began measuring to the end of the year, in standard cubic feet.

T = Total hours during the year in which at least one of the pumps connected to the supply line was operating, hr/yr.

T_M = Total hours during the year when the natural gas supply flow meter was measuring flow.

(B) Convert the natural gas volumetric flow from paragraph (c)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (c)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total annual mass of natural gas used in the pumps that are connected to the measured supply line by escalating the measured mass flow by the ratio of the total hours for which natural gas was supplied to the pumps to the number of hours the natural gas supplied to the pumps was measured as specified in Equation W–2A of paragraph (c)(1)(i)(A) of this section, except that E_s and $E_{s,M}$ are in metric tons per year instead of standard cubic feet per year.

(B) Convert the cumulative mass flow from paragraph (c)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(2) *Calculation Method 2.* Except as provided in paragraph (c)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas driven pneumatic pump at your facility that vents directly to the atmosphere as specified in paragraphs (c)(2)(i) through (vii) of this section. You must exclude the counts of pumps measured according to paragraph (c)(1) of this section from the counts of pumps to be measured and for which emissions are calculated according to the requirements in this paragraph (c)(2).

(i) Measure all natural gas driven pneumatic pumps at your facility at least once every 5 years. If you elect to measure your pneumatic pumps over multiple years, you must measure approximately the same number of pumps each year. When you measure the emissions from natural gas driven pneumatic pumps at a well-pad or gathering and boosting site, you must measure all pneumatic pumps that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year.

(ii) Determine the volumetric flow rate of each natural gas driven pneumatic pump (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (c)(2)(ii)(A) through (D) of this section.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth § 98.234(d), you must measure the emissions from each pump for a minimum of 5 minutes, during a period when the pump is continuously pumping liquid.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c), except under § 98.234(c)(2), only one bag must be filled to have a valid measurement. You must collect sample for a minimum of 5 minutes, or until the bag is full, whichever is shorter, during a period when the pump is continuously pumping liquid. If the bag is not full after 5 minutes, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (c)(2)(ii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas driven pneumatic pump vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section. Convert the measured flow during the test period to standard cubic feet per hour, as appropriate.

(iii) Calculate the volume of natural gas emitted from each natural gas driven pneumatic pump vent as the product of the natural gas emissions flow rate measured in paragraph (c)(2)(ii) of this section and the number of hours that liquid was pumped by the pneumatic pump in the calendar year.

(iv) For each pneumatic pump, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (c)(2)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each pneumatic pump, convert the GHG volumetric emissions at standard conditions determined in paragraph (c)(2)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (c)(2)(v) of this section.

(vii) If you chose to conduct natural gas pneumatic pump measurements over multiple years, ''n,'' according to paragraph (c)(2)(i) of this section, then you must calculate the emissions from all pneumatic pumps at your facility as specified in paragraph (c)(2)(vii)(A) through (D) of this section.

(A) Use the emissions calculated in paragraph (c)(2)(vi) of this section for the pumps measured during the reporting year.

(B) Calculate the whole gas emission factor for pneumatic pumps at the facility using Equation W–2B of this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic pump vent measurements were made according to Calculation Method 2 in paragraph (c)(2) of this section (*e.g.,* if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_s = \frac{\sum_{y=1}^{n} MT_{s,y}}{\sum_{y=1}^{n} Count_y} \qquad \text{(Eq. W-2B)}$$

Where:

EF_s = Whole gas population emission factor for natural gas pneumatic pump vents, in standard cubic feet per hour per pump.

$MT_{s,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions during year ''y'' in standard cubic feet per hour, as calculated in paragraph (c)(2)(iii) of this section.

$Count_y$ = Count of natural gas driven pneumatic pump vents measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic pump vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps that were not measured during the reporting year using Equation W–2C of this section.

$$E_{s,i} = Count \times EF_s \times GHG_i \times T \qquad \text{(Eq. W-2C)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas driven pneumatic pump vents, for GHGi.

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere and that were not directly measured according to the requirements in paragraphs (c)(1) or (c)(2)(ii) of this section.

EF_s = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) as calculated using Equation W–2B of this section.

GHG_i = Concentration of GHGi, CH_4 or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps that vented directly to the atmosphere were pumping liquid using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(D) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions calculated using Equation W–2C of this section using calculations in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (c)(2)(vii)(A) and (D) of this section to calculate the total CH_4 and CO_2 mass emissions for Calculation Method 2.

(3) *Calculation Method 3.* If you elect not to measure emissions as specified in Calculation Method 2, then you must use the applicable method specified in paragraphs (c)(3)(i) and (ii) of this section to calculate CH_4 and CO_2 emissions from all natural gas driven pneumatic pumps that are vented directly to the atmosphere at your facility and that are not measured according to paragraph (c)(1) of this section. You must exclude the counts of devices measured according to paragraph (c)(1) of this section from the counts of pumps for which emissions are calculated according to the requirements in this paragraph (c)(3).

(i) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps using Equation W–2C of this section, except use the appropriate default whole gas population emission factor for natural gas pneumatic pump vents (in standard cubic feet per hour per device) as provided in table W–1 to this subpart.

(ii) Convert the CH_4 and CO_2 volumetric emissions determined according to paragraph (c)(3)(i) of this section to CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(4) *Routing to flares, combustion, or vapor recovery systems.* Calculate emissions from natural gas driven pneumatic pumps for periods when they are routed to flares or combustion as specified in paragraph (c)(4)(i) or (ii) of this section, as applicable. If a pump was vented directly to the atmosphere for part of the year and routed to a flare or combustion during another part of the year, then calculate emissions from the time the pump vents directly to the atmosphere as specified in paragraphs (c)(2) or (3) of this section and calculate emissions from the time the pump was routed to a flare or combustion as specified in paragraphs (c)(4)(i) and (ii) of this section, as applicable. For emissions that are collected in a vapor recovery system that is never routed to combustion during the reporting year, paragraphs (c)(2) and (3) and paragraphs (c)(4)(i) and (ii) of this section do not apply and no emissions calculations are required.

(i) If any natural gas driven pneumatic pumps were routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(ii) If emissions from any natural gas driven pneumatic pumps were routed to combustion, you must calculate emissions for the combustion equipment as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z).

(d) *Acid gas removal unit (AGR) vents and Nitrogen removal unit (NRU) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CH_4 and CO_2 vented directly to the atmosphere or emitted through a sulfur recovery plant, using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (11) of this section, as applicable. For NRU vents, calculate emissions for CH_4 vented directly to the atmosphere using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (11) of this section, as applicable. If any AGR vents or NRU vents are routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). If any AGR vents or NRU vents are routed through an engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement) (*i.e.,* routed to combustion, you must calculate CH_4, CO_2, and N_2O emissions as specified in subpart C of this part or as specified in paragraph (z) of this section, as applicable.

(1) *Calculation Method 1.* If you operate and maintain a continuous emissions monitoring system (CEMS) that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Method in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) *Calculation Method 2.* For CO_2 emissions, if a CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section. For CH_4 emissions, if a vent meter is installed, including the volumetric flow rate monitor on a CEMS for CO_2, use the CH_4 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,i} = V_a \times Vol_i \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,i}$ = Annual total volumetric GHGi (either CO_2 or CH_4) emissions at actual conditions, in cubic feet per year.

V_a = Total annual volume of vent gas flowing out of the AGR or NRU in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_i = Annual average volumetric fraction of GHGi (either CO_2 or CH_4) content in vent gas flowing out of the AGR or NRU as determined in paragraph (d)(7) of this section.

(3) *Calculation Method 3.* If a CEMS for CO_2 or a vent meter is not installed, you may use the inlet and/or outlet gas

flow rate of the AGR or NRU to calculate emissions for CH_4 and CO_2 using Equations W–4A, W–4B, or W–4C of this section. If inlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use Equation W–4A. If outlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use Equation W–4B. If inlet gas flow rate and outlet gas flow rate are known, use Equation W–4C.

$$E_{a,i} = V_{in} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{O,i}}\right] \times Vol_{EM,i} \quad \text{(Eq. W-4A)}$$

$$E_{a,i} = V_{out} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{I,i}}\right] \times Vol_{EM,i} \quad \text{(Eq. W-4B)}$$

$$E_{a,i} = \left(V_{in} \times Vol_{I,i}\right) - \left(V_{out} \times Vol_{O,i}\right) \quad \text{(Eq. W-4C)}$$

Where:

$E_{a,i}$ = Annual total volumetric GHGi (either CH_4 or CO_2) emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR or NRU in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR or NRU in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

$Vol_{I,i}$ = Annual average volumetric fraction of GHGi (either CH_4 or CO_2) content in natural gas flowing into the AGR or NRU as determined in paragraph (d)(7) of this section.

$Vol_{O,i}$ = Annual average volumetric fraction of GHGi (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU as determined in paragraph (d)(8) of this section.

$Vol_{EM,i}$ = Annual average volumetric fraction of GHGi (either CH_4 or CO_2) content in the vent gas flowing out of the AGR or NRU as determined in paragraph (d)(6) of this section.

(4) *Calculation Method 4.* If CEMS for CO_2 or a vent meter is not installed, you may calculate CH_4 and CO_2 emissions from an AGR or NRU using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CH_4 and CO_2 emissions. A minimum of the parameters listed in paragraph (d)(4)(i) through (x) of this section, as applicable, must be used to characterize emissions. If paragraph (d)(4)(i) through (x) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions over the time period covered by the simulation. Determine all other applicable parameters in paragraph (d)(4)(i) through (x) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.,* if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year).

(i) Natural gas feed temperature, pressure, and flow rate (must be measured).

(ii) Acid gas content of feed natural gas (must be measured).

(iii) Acid gas content of outlet natural gas.

(iv) CH_4 content of feed natural gas (must be measured).

(v) CH_4 content of outlet natural gas.

(vi) For NRU, nitrogen content of feed natural gas (must be measured).

(vii) For NRU, nitrogen content of outlet natural gas.

(viii) Unit operating hours, excluding downtime for maintenance or standby.

(ix) Exit temperature of natural gas.

(x) For AGR, solvent type, pressure, temperature, circulation rate, and composition.

(5) *Flow rate of inlet.* For Calculation Method 3, determine the gas flow rate of the inlet when using Equation W–4A or W–4C of this section or the gas flow rate of the outlet when using Equation W–4B or W–4C of this section for the natural gas stream of an AGR or NRU using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) *Composition of vent gas.* For Calculation Method 2 or Calculation Method 3 when using Equation W–4A or W–4B of this section, if a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream for each quarter that the AGR or NRU is operating to determine Voli in Equation W–3 of this section or Equation W–4A or W–4B of this section, according to the methods set forth in § 98.234(b).

(7) Composition of inlet gas stream. For Calculation Method 3, if a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream for each quarter that the AGR or NRU is operating to determine VolI,i in Equation W–4A, W–4B, or W–4C of this section, according to the methods set forth in § 98.234(b).

(8) *Composition of outlet gas stream.* For Calculation Method 3, determine annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU using one of the methods specified in paragraphs (d)(8)(i) through (iii) of this section.

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

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet natural gas stream for each quarter that the AGR or NRU is operating to determine $Vol_{O,i}$ in Equation W–4A, W–4B, or W–4C of this section, according to the methods set forth in § 98.234(b).

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas and the outlet quality specification for CH_4 in natural gas.

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

(10) *Mass emissions.* Calculate annual mass CH_4 and CO_2 emissions using calculations in paragraph (v) of this section.

(11) *Emissions recovered and transferred outside the facility.* Determine if CO_2 emissions from the AGR are recovered and transferred outside the facility. Adjust the CO_2 emissions estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of CO_2 emissions recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (5) of this section. For glycol dehydrators that have an annual average daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day, use Calculation Method 1 in paragraph (e)(1) of this section. For glycol dehydrators that have an annual average of daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day, use either Calculation Method 1 in paragraph (e)(1) of this section or Calculation Method 2 in paragraph (e)(2) of this section. If you are required to or elect to use the method in paragraph (e)(1) of this section, you must use the results of the model to determine annual mass emissions. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(4) of this section. If emissions from dehydrator vents are routed to a regenerator firebox/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(5) of this section. If any dehydrator vents are routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators by using a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, or GRI–GLYCalcTM, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas, and a gas injection pump or gas assist pump. If you elect to use ProMax®, you must use version 5.0 or above. Emissions must be modeled from both the still vent and, if applicable, the flash tank vent. A minimum of the parameters listed in paragraph (e)(1)(i) through (xi) of this section, as applicable, must be used to characterize emissions. If paragraph (e)(1)(i) through (xi) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation. Determine all other applicable parameters in paragraph (e)(1)(i) through (xi) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.,* if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year).

(i) Feed natural gas flow rate (must be measured).

(ii) Feed natural gas water content (must be measured).

* * * * *

(x) Wet natural gas temperature and pressure at the absorber inlet (must be measured).

(xi) Wet natural gas composition. Measure this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) and (B) of this section.

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

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

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators using Equation W–5 of this section, and then calculate the collective CH_4 and CO_2 mass emissions from the volumetric emissions using the procedures in paragraph (v) of this section:

* * * * *

Count = Total number of glycol dehydrators that have an annual average daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day for which you elect to use this Calculation Method 2.

* * * * *

(3) *Calculation Method 3.* For dehydrators of any size that use desiccant, you must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W–6 of this section. From volumetric natural gas emissions, calculate both CH_4 and CO_2 volumetric and mass emissions using the procedures in paragraphs (u) and (v) of this section. Desiccant dehydrator emissions covered in this paragraph do not have to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

* * * * *

(4) *Emissions vented directly to atmosphere from dehydrators routed to a vapor recovery system, flare, or regenerator firebox/fire tubes.* If the dehydrator(s) has a vapor recovery system, routes emissions to a flare, or routes emissions to a regenerator firebox/fire tubes and you use Calculation Method 1 or Calculation Method 2 in paragraph (e)(1) or (2) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes as specified in paragraphs (e)(4)(i) and (ii) of this section. If the dehydrator(s) has a vapor recovery system or routes emissions to a flare and you use Calculation Method 3 in paragraph (e)(3) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (e)(4)(iii) of this section.

(i) When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate maximum potential annual vented emissions as specified in paragraph (e)(1) or (2) of this section, and calculate an average hourly vented emissions rate by dividing the maximum potential annual vented emissions by the number of hours that the dehydrator was in operation.

(ii) To calculate total emissions vented directly to atmosphere during periods when the dehydrator was not routing emissions to a vapor recovery system, flare, or regenerator firebox/fire tubes for dehydrator(s) with emissions calculated using Calculation Method 1 or 2, multiply the average hourly vented emissions rate determined in paragraph (e)(4)(i) of this section by the number of hours that the dehydrator vented directly to the atmosphere. Determine the number of hours that the dehydrator vented directly to atmosphere by subtracting the hours that the dehydrator was connected to a vapor recovery system, flare, or regenerator firebox/fire tubes (based on engineering estimate and best available data) from the total operating hours for the dehydrator in the calendar year. You must take into account periods with reduced capture efficiency of the vapor recovery system, flare, or regenerator firebox/fire tubes. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(iii) When emissions from dehydrator(s) are calculated using Calculation Method 3, calculate total annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes by determining of the number of depressurization events (including portions of an event) that vented to atmosphere based on engineering estimate and best available data. You must take into account periods with reduced capture efficiency of the vapor recovery system or flare. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(5) *Combustion emissions from routing to regenerator firebox/fire tubes.* If any dehydrator emissions are routed to a regenerator firebox/fire tubes, calculate emissions from these devices attributable to dehydrator flash tank vents or still vents as specified in paragraphs (e)(5)(i) through (iii) of this section. If you operate a CEMS to monitor the emissions from the regenerator firebox/fire tubes, calculate emissions as specified in paragraph (e)(5)(iv) of this section.

(i) Determine the volume of the total emissions that is routed to a regenerator firebox/fire tubes as specified in paragraph (e)(5)(i)(A) or (B) of this section.

(A) Measure the flow from the dehydrator(s) to the regenerator firebox/fire tubes using a continuous flow measurement device. If you continuously measure flow to the regenerator firebox/fire tubes, you must use the measured volumes to calculate emissions from the regenerator firebox/fire tubes.

(B) Using engineering estimates based on best available data, determine the volume of the total emissions estimated in paragraph (e)(1), (2), or (3) of this section, as applicable, that is routed to the regenerator firebox/fire tubes.

(ii) Determine composition of the gas routed to a regenerator firebox/fire tubes as specified in paragraph (e)(5)(ii)(A) or (B) of this section.

(A) Use the appropriate vent emissions as determined in paragraph (e)(1) or (2) of this section.

(B) Measure the composition of the gas from the dehydrator(s) to the regenerator firebox/fire tubes using a continuous composition analyzer. If you continuously measure gas composition, then those measured data must be used to calculate dehydrator emissions from the regenerator firebox/fire tubes.

(iii) Determine GHG volumetric emissions at actual conditions from the regenerator firebox/fire tubes using Equations W–39A, W–39B, and W–40 in paragraph (z)(3) of this section. Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section. Calculate both GHG mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(iv) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the regenerator firebox/fire tubes, you must calculate only CO_2 emissions for the regenerator firebox/fire tubes. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate emissions from a regenerator firebox/fire tubes, the requirements specified in paragraphs (e)(5)(ii) and (iii) of this section are not required.

(f) *Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading when the well is unloaded to the atmosphere or a control device using one of the calculation methods described in paragraph (f)(1), (2), or (3) of this section. Once every 3 consecutive calendar years or on a more frequent basis, you must use Calculation Method 1 to calculate emissions from well venting for liquids unloading for each well. Calculate annual CH_4 and CO_2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1) *Calculation Method 1.* Calculate emissions from manual and automated unloadings at wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter 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 the total emissions from well venting to the atmosphere for liquids unloading using Equation W–7A of this section. Equation W–7A must be used for each unloading type combination (automated plunger lift unloadings, manual plunger lift unloadings, automated unloadings without plunger lifts and manual unloadings without plunger lifts) for any tubing diameter group and pressure group combination in each sub-basin.

$$E_a = FR \times T_p \qquad \text{(Eq. W-7A)}$$

Where:

E_a = Annual natural gas emissions for each well of the same tubing diameter group and pressure group combination in the sub-basin at actual conditions, a, in cubic feet. Calculate emissions from wells with automated plunger lift unloadings, wells with manual plunger lift unloadings, wells with automated unloadings without plunger lifts and wells with manual unloadings without plunger lifts separately.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, Tp, using Equation W–7B of this section.

$$T_p = \frac{HR_p}{MP_p} \times D_p \quad \text{(Eq. W-7B)}$$

Where:

HR_p = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MP_p = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate (''FR'' in Equation W–7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with automated plunger lift unloadings, wells with manual plunger lift unloadings, wells with automated unloadings without plunger lifts and wells with manual unloadings without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere or a control device.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to each well in the same pressure group that have the same tubing diameter group, for the number of hours of each well is vented.

(C) If using Calculation Method 1 more frequently than once every 3 years, you must calculate a new average flow rate each calendar year that you use Calculation Method 1. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

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

(2) *Calculation Method 2.* Calculate the total emissions for each well from manual and automated well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W–8 of this section.

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right) \times Z_{p,q}\right) \quad \text{(Eq. W-8)}$$

Where:

E_s = Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year

N_p = Total number of unloading events in the monitoring period per well, p.

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

CD_p = Casing internal diameter for well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for well, p, in feet.

SP_p = For well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for the well, you may determine the casing pressure by multiplying the tubing pressure of the well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

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

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right) \times Z_{p,q}\right) \quad \text{(Eq. W-9)}$$

Where:

E_s = Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year.

N_p = Total number of unloading events in the monitoring period per well, p.

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

TD_p = Tubing internal diameter for well, p, in inches.

WD_p = Tubing depth to plunger bumper for well, p, in feet.

SP_p = Flow-line pressure for well p in pounds per square inch absolute (psia), using engineering estimate based on best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that well, p, was left open to the atmosphere during each unloading event, q.

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

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

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

* * * * *

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers in a sub-basin and well type combination and Equation W–10B applies when the gas flowback vent or flare volume is measured for each completion or workover in a sub-basin and well type combination. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W–10A, you must follow the procedures specified in paragraph (g)(1) of this section. If you elect to use Equation W–10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section.

$$E_{s,n} = \sum_{p=1}^{CW} \left[T_{p,s,cw} \times FRM_s \times PR_{s,p,cw} - EnF_{s,p,cw} + \left[T_{p,i,cw} \times FRM_i \div 2 \times PR_{s,p,cw} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{CW} \left[FV_{s,p,cw} - EnF_{s,p,cw} + \left[T_{p,i,cw} \times FR_{p,i,cw} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each well.

CW = Total number of completions or workovers using hydraulic fracturing for each well, p.

$T_{p,s,cw}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for each completion or workover, in hours, for each well, p, during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i,cw}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, in hours, for each well, p, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p,cw}$ = Average gas production flow rate during the first 30 days of production after each completion of a newly drilled well or well workover using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p,cw}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p,cw}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback during each completion or workover for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p,cw}$ is 0.

$FV_{s,p,cw}$ = Flow volume of vented or flared gas for each completion or workover at each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i,cw}$ = Flow rate vented or flared of each completion or workover for each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b).

(1) If you elect to use Equation W–10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

* * * * *

(iii) * * *

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W–33 in paragraph (t) of this section. You may not use flow volume as used in Equation W–10B of this section converted to a flow rate for this parameter.

* * * * *

N = Number of measured well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) * * *

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions.

* * * * *

N = Number of measured well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

* * * * *

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using Equation W–13A of this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using Equation W–13B of this section. You must convert annual volumetric natural gas emissions to CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (h)(1) of this section. If emissions from gas well venting during completions and workovers without hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section.

$$E_{s,wo} = N_{wo} * EF_{wo} \qquad \text{(Eq. W-13A)}$$

$$E_{s,p} = V_p \times T_p \qquad \text{(Eq. W-13B)}$$

Where:

$E_{s,wo}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well workovers without hydraulic fracturing.

N_{wo} = Number of workovers per well that do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. Use 3,114 standard cubic feet natural gas per well workover without hydraulic fracturing.

$E_{s,p}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well completions without hydraulic fracturing.

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

T_p = Time that gas is vented to either the atmosphere or a flare for each well, p, undergoing completion without hydraulic fracturing, in hours during the year.

* * * * *

(i) * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) of this section or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. Categorize equipment and event types for each industry segment as specified in paragraph (i)(2)(iv) of this section.

(i) * * *

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown ''p''. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown ''p''. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure at the beginning of the blowdown.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown ''p''; 0 if blowdown volume is purged using non-GHG gases. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure at the end of the blowdown.

* * * * *

(iv) Categorize blowdown vent stack emission events as specified in paragraphs (i)(2)(iv)(A) and (B) of this section, as applicable.

(A) For the onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and onshore petroleum and natural gas gathering and boosting industry segments, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* physical volumes associated with piping for which the entire physical volume is located within the facility boundary), pipeline venting (*i.e.,* physical volumes associated with pipelines for which a portion of the physical volume is located outside the facility boundary and the remainder, including the blowdown vent stack, is located within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.

(B) For the onshore natural gas transmission pipeline and natural gas distribution industry segments, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

* * * * *

(j) *Hydrocarbon liquids and produced water storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids or produced water from onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), and onshore natural gas processing facilities as specified in this paragraph (j). For wells, gas-liquid separators, or onshore petroleum and natural gas gathering and boosting or onshore natural gas processing non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of hydrocarbon liquids greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells, gas-liquid separators, or non-separator equipment with annual average daily throughput of hydrocarbon liquids greater than 0 barrels per day and less than 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. Annual average daily throughput of hydrocarbon liquids should be calculated using the flow out of the separator, well, or non-separator equipment determined over the actual days of operation. For atmospheric pressure storage tanks receiving produced water, calculate annual CH_4 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. If you are required to or elect to use the method in paragraph (j)(1) of this section, you must use the results of the model to determine annual CH_4 and, if applicable, CO_2 emissions. If you use Calculation Method 1 or Calculation Method 2 for gas-liquid separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(5) of this section. If emissions from atmospheric pressure storage tanks are routed to a vapor recovery system, you must calculate CH_4 and CO_2 annual emissions as specified in paragraph (j)(4) of this section. If emissions from atmospheric pressure storage tanks are routed to a flare, determine flared emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). For atmospheric pressure storage tanks routing emissions to a vapor recovery system or a flare, calculate annual emissions vented directly to atmosphere as specified in paragraph (j)(4) of this section.

(1) *Calculation Method 1.* For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. For atmospheric pressure storage tanks receiving produced water, calculate annual CH_4 emissions using operating

conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, or, for atmospheric pressure storage tanks receiving hydrocarbon liquids from gas-liquid separator or non-separator equipment, API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the hydrocarbon liquids or produced water from the well, separator, or non-separator equipment enter an atmospheric pressure storage tank. If you elect to use ProMax®, you must use version 5.0 or above. A minimum of the parameters listed in paragraphs (j)(1)(i) through (vii) of this section, as applicable, must be used to characterize emissions. If paragraphs (j)(1)(i) through (vii) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation. Determine all other applicable parameters in paragraphs (j)(1)(i) through (vii) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.,* if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year).

(i) Well, separator, or non-separator equipment temperature (must be measured).

(ii) Well, separator, or non-separator equipment pressure (must be measured).

(iii) For atmospheric pressure storage tanks receiving hydrocarbon liquids, sales or stabilized hydrocarbon liquids API gravity (must be measured).

(iv) Sales or stabilized hydrocarbon liquids or produced water production rate (must be measured).

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Well, separator, or non-separator equipment hydrocarbon liquids or produced water composition and Reid vapor pressure (must be measured). Use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b) to sample and analyze hydrocarbon liquids or produced water composition and Reid vapor pressure.

(2) *Calculation Method 2.* For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section. For atmospheric pressure storage tanks receiving produced water, calculate annual CH_4 emissions using the methods in paragraph (j)(2)(i) of this section.

(i) Assume that all of the CH_4 and, if applicable, CO_2 in solution at well, separator, or non-separator equipment temperature and pressure is emitted from hydrocarbon liquids or produced water sent to atmosphere pressure storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze hydrocarbon liquids or produced water composition at well, separator, or non-separator pressure and temperature.

(ii) [Reserved]

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids as specified in paragraph (j)(3)(i) of this section. Calculate CH_4 emissions from atmospheric pressure storage tanks receiving produced water as specified in paragraph (j)(3)(ii) of this section.

(i) Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids using Equation W–15A of this section:

$$E_{s,i} = EF_i \times Count \times 1{,}000 \qquad \text{(Eq. W-15A)}$$

Where:

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

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput greater than 0 barrels per day and less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed hydrocarbon liquids directly to the atmospheric pressure storage tank for which you elect to use this Calculation Method 3.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(ii) Calculate CH4 emissions from atmospheric pressure storage tanks receiving produced water using Equation W–15B of this section:

$$Mass_{CH_4} = EF_{CH_4} \times FR \times 0.001 \qquad \text{(Eq. W-15B)}$$

Where:

$Mass_{CH4}$ = Annual total CH_4 emissions in metric tons.

EF_{CH4} = Population emission factor for produced water in metric tons CH_4 per thousand barrels produced water per year. For produced water streams from separators, wells, or non-separator equipment with pressure less than or equal to 50 psi, use 0.0015. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 50 but less than or equal to 250 psi, use 0.0142. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 250 psi, use 0.0508. Pressure should be representative of separators, wells, or non-separator equipment that feed produced water directly to the atmosphere pressure storage tank.

FR = Annual flow rate of produced water to atmospheric pressure storage tanks, in barrels.

0.001 = Conversion from barrels to thousand barrels.

(4) *Routing to vapor recovery systems or flares.* If the atmospheric pressure storage tank receiving your hydrocarbon liquids or produced water has a vapor recovery system or routes emissions to

a flare, calculate annual emissions vented directly to atmosphere from the storage tank during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (j)(4)(i) of this section. Determine recovered mass as specified in paragraph (j)(4)(ii) of this section.

(i) For an atmospheric pressure storage tank that routes any emissions to a vapor recovery system or a flare, calculate vented emissions as specified in paragraphs (j)(4)(i)(A) through (E) of this section.

(A) Calculate maximum potential vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, and calculate an average hourly vented emissions rate by dividing the maximum potential vented emissions by the number of hours that the tank was in operation.

(B) To calculate vented emissions during periods when the tank was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the tank vented directly to the atmosphere. Determine the number of hours that the tank vented directly to atmosphere by subtracting the hours that the tank was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the tank in the calendar year. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(C) During periods when a thief hatch is open or not properly seated and emissions from the tank are routed to a vapor recovery system or a flare, assume the capture efficiency of the vapor recovery system or a flare is 0 percent. To calculate vented emissions during such periods, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the thief hatch is open or not properly seated. Determine the number of hours that the thief hatch is open or not properly seated as specified in paragraph (j)(7) of this section.

(D) Calculate vented emissions not captured by the vapor recovery system or a flare due to causes other than open or not properly seated thief hatches based on best available data.

(E) Calculate total emissions vented directly to atmosphere as the sum of the emissions calculated as specified in paragraphs (j)(4)(i)(B) through (D) of this section.

(ii) Using engineering estimates based on best available data, determine the portion of the total emissions estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (*e.g.,* when a thief hatch is open or not properly seated) when calculating mass recovered as specified in paragraphs (j)(4)(i)(C) and (D) of this section.

(5) *Gas-liquid separator dump valves.* If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves that did not close properly during the calendar year by using Equation W–16 of this section. Determine the total time a dump valve did not close properly in the calendar year (T_{dv}) as specified in paragraph (j)(5)(i) of this section.

$$E_{s,I,dv} = CF_{dv} \times \frac{E_{s,i}}{8,760} \times T_{dv} \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,dv}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet from atmospheric pressure storage tanks that resulted from the dump valve on an associated gas-liquid separator that did not close properly.

CF_{dv} = Correction factor for tank emissions for time period Td_v is 2.87 for crude oil production. Correction factor for tank emissions for time period Td_v is 4.37 for gas condensate production.

$E_{s,i}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) as determined in paragraphs (j)(1) and (2) and, if applicable, (j)(4) of this section, in standard cubic feet per year, from atmospheric pressure storage tanks with dump valves on an associated gas-liquid separator that did not close properly.

8,760 = Conversion to hourly emissions.

T_{dv} = Total time a dump valve did not close properly in the calendar year as determined in paragraph (j)(5)(i) of this section, in hours.

(i) You must perform a visual inspection of each gas-liquid separator liquid dump valve to determine if the valve is stuck in an open or partially open position, in accordance with paragraph (j)(5)(i)(A) and (B) of this section.

(A) Visual inspections must be conducted at least once in a calendar year.

(B) If stuck gas-liquid separator liquid dump valve is identified, the dump valve must be counted as being open since the beginning of the calendar year, or from the previous visual inspection that did not identify the dump valve as being stuck in the open position in the same calendar year. If the dump valve is fixed following visual inspection, the time period for which the dump valve was stuck open will end upon being repaired. If a stuck dump valve is identified and not repaired, the time period for which the dump valve was stuck open must be counted as having occurred through the rest of the calendar year.

(ii) [Reserved]

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

(7) *Thief hatches.* If a thief hatch sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open or not properly seated. An applicable operating thief hatch sensor must be capable of transmitting and logging data whenever a thief hatch is open or not properly seated, as well as when the thief hatch is subsequently closed. If a thief hatch sensor is not operating, you must perform a visual inspection of each thief hatch on a controlled atmospheric pressure storage tank in accordance with paragraph (j)(7)(i) through (iii) of this section.

(i) For thief hatches on atmospheric pressure storage tanks subject to the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least as frequent as the required visual, audible, or olfactory fugitive emissions components surveys described in § 60.5397b or the applicable approved state plan or applicable Federal plan in part 62. If the time between required visual, audible, or olfactory fugitive emissions components surveys described in § 60.5397b or the applicable approved state plan or applicable Federal plan in part 62 is greater than one year, visual inspections must be conducted at least annually.

(ii) For thief hatches on atmospheric pressure storage tanks not subject to the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least once in a calendar year.

(iii) If one visual inspection is conducted in the calendar year, assume the thief hatch was open for the entire calendar year. If multiple visual inspections are conducted in the calendar year, assume a thief hatch found open in the first visual inspection was open since the beginning of the year until the date of the visual inspection; assume a thief hatch found open in the last visual inspection of the year was open from the preceding visual inspection through the end of the year; assume a thief hatch found open in a visual inspection between the first and last visual inspections of the year was open since the preceding visual inspection until the date of the visual inspection.

(k) *Condensate storage tanks.* For vent stacks connected to one or more condensate storage tanks, either water or hydrocarbon, without vapor recovery, flares, or other controls, in onshore natural gas transmission compression or underground natural gas storage, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (4) of this section.

* * * * *

(l) *Well testing venting and flaring.* Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section.

* * * * *

(3) Estimate venting emissions using Equation W–17A (for oil wells) or Equation W–17B (for gas wells) of this section for each well tested during the reporting year.

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

$$E_{a,n} = PR * D \qquad \text{(Eq. W-17B)}$$

Where:

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

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

FR = Average annual flow rate in barrels of oil per day for the oil well being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well being tested.

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

* * * * *

(m) *Associated gas venting and flaring.* Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l) of this section) as specified in paragraphs (m)(1) through (4) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section.

* * * * *

(3) Estimate venting emissions using Equation W–18 of this section. Alternatively, if you measure the flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.

$$E_{s,n,p} = \left(GOR_p \times V_p\right) - SG_p \qquad \text{(Eq. W-18)}$$

Where:

$E_{s,n,p}$ = Annual volumetric natural gas emissions at each well from associated gas venting at standard conditions, in cubic feet.

GOR_p = Gas to oil ratio, for well p, in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced, for well p, in barrels in the calendar year only during time periods in which associated gas was vented or flared.

SG_p = Volume of associated gas sent to sales or volume of associated gas used for other purposes at the facility site, including powering engines, separators, safety systems and/or combustion equipment and not flared or vented, for well p, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared.

* * * * *

(n) *Flare stack emissions.* Except as specified in paragraph (n)(9) of this section, calculate CO_2, CH_4, and N_2O emissions from each flare stack as specified in paragraphs (n)(1) through (8) of this section. For each flare, disaggregate the total flared emissions to applicable source types as specified in paragraph (n)(10) of this section.

(1) *Flow measurement.* Measure total flow to the flare as specified in either paragraph (n)(1)(i) or (ii) of this section.

(i) Use a continuous parameter monitoring system for measuring the flow of gas to the flare downstream of any sweep, purge, or auxiliary gas addition. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement. The continuous parameter monitoring system must measure data values at least once every hour.

(ii) Use a continuous parameter monitoring system for measuring the flow of gas from each source that routes gas to the flare, including purge gas, sweep gas, and auxiliary fuel. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement. If the emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may conduct the measurement in the manifold instead of from each source that is routed to the manifold.

(2) *Pilot.* Continuously monitor for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(i) of this section or visually inspect for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(ii) of this section. If you continuously monitor, then periods when the flare are unlit must be determined based on those data.

(i) At least once every five minutes monitor for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this part 98. Track the length of time over all periods when the flare is unlit. Use the measured flow during these time periods, as determined from measurements obtained under paragraph (n)(1) of this section, to calculate the fraction of the total annual volume that is routed to the flare when it is unlit. If the monitoring device is out of service for more than one week, then visually inspect for the presence of a pilot flame or combustion flame at least once per week for the first 4 weeks that a monitoring device is out of service or until a repaired or new device is operational, whichever period is shorter. If the continuous monitoring device is out of service for less than one week, then at least one visual inspection must be conducted during the outage. If a flame is not detected during a weekly visual inspection, assume the pilot has been unlit since the previous inspection or the last time the continuous monitoring device detected a flame, and assume that the pilot remains unlit until a subsequent inspection or continuous monitoring device detects a flame. If the monitoring device outage lasts more than 4 weeks, then you may switch to conducting inspections at least once per month in accordance with paragraph (n)(2)(ii) of this section.

(ii) At least once per month visually inspect for the presence of a pilot flame or combustion flame. If a flame is not detected, assume the pilot has been unlit since the previous inspection and that it remains unlit until a subsequent inspection detects a flame. Use the sum of the measured flows, as determined from measurements obtained under paragraph (n)(1) of this section, during all time periods when the pilot was determined to be unlit, to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

(3) *Gas composition.* Determine the composition of the inlet gas to the flare as specified in either paragraph (n)(3)(i), (ii), (iii), or (iv) of this section.

(i) Use a continuous gas composition analyzer on the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition to determine the annual average mole fractions of methane, ethane, propane, butane, pentanes plus, and CO_2.

(ii) Take samples of the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition at least once every quarter in which gas is routed to the flare and analyze for methane, ethane, propane, butane, pentanes plus, and CO_2 constituents, Determine the annual average concentration of each constituent as the flow-weighted annual average of all measurements for that constituent during the year.

(iii) Use a continuous gas composition analyzer on the emissions streams from each emission source that routes gas to the flare. Also take samples of purge gas, sweep gas, and auxiliary fuel at least annually, and analyze for methane ethane, propane, butane, pentanes plus, and CO_2. If the emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may measure gas composition in the manifold instead of from each source that is routed to the manifold. Determine the flow-weighted annual average concentration of each constituent.

(iv) Take samples of the emission streams from each source that routes gas to the flare at least once every quarter in which gas is routed to the flare and analyze for methane, ethane, propane, butane, pentanes plus, and CO_2. Also take samples of purge gas, sweep gas, and auxiliary fuel at least annually, and analyze for methane, ethane, propane, butane, pentanes plus, and CO_2. If the emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may measure gas composition in the manifold instead of from each source that is routed to the manifold. Determine the annual average concentration of each constituent in each stream as the flow-weighted average of all measurements for that constituent during the year.

(4) *Combustion efficiency.* Use the applicable default combustion efficiency specified in paragraphs (n)(4)(i) through (iii) of this section. If you change the Tier with which you comply during a year, then use the applicable default combustion efficiencies in paragraphs (n)(4)(i) through (iii) of this section for portions of the year during which the different monitoring methodologies were used, and calculate a time-weighted average combustion efficiency to report for the flare.

(i) *Tier 1.* If you monitor the flare as specified in § 63.670 and § 63.671 of this chapter, then use a default combustion efficiency of 98 percent. The alternative means of emissions limitation specified in § 63.670(r) of this chapter do not apply for the purposes of this paragraph (n). References to deviations in § 63.670(b) of this chapter do not apply for the purposes of this paragraph (n). References to refineries or refinery process units in § 63.670 of this chapter mean facilities in any of the industry segments specified in § 98.230 for the purposes of this paragraph (n). Reporting requirements in § 63.670(q) of this chapter mean recordkeeping requirements for the purposes of this paragraph (n).

(ii) *Tier 2.* If you are required to monitor the flare as specified in § 60.5417b(d)(1)(viii) of this chapter, or you elect to implement the flare monitoring requirements in § 60.5417b(d)(1)(viii) of this chapter, then use a default combustion efficiency of 95 percent. The exemptions from monitoring gas flow in § 60.5417b(d)(1)(viii)(D)(*1*) through (*4*) of this chapter do not apply for the purposes of this paragraph (n).

(iii) *Tier 3.* If you do not monitor the flare as specified in either paragraph (n)(4)(i) or (ii) of this section, then use a default combustion efficiency of 92 percent.

(5) *Calculate CH_4 and CO_2 emissions.* Calculate GHG volumetric emissions from flaring at standard conditions using Equations W–19 and W–20 of this section and as specified in paragraphs (n)(5)(i) through (iv) of this section.

$$E_{s,CH_4} = V_s * X_{CH_4} * \left[(1-\eta) * Z_L + Z_U\right] \text{ (Eq. W-19)}$$

$$E_{s,CO_2} = V_s * X_{CO_2} + \sum_{j=1}^{5} \left(\eta * V_s * Y_j * R_j * Z_L\right) \text{ (Eq. W-20)}$$

Where:

$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare.

X_{CH4} = Annual average mole fraction of CH_4 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(3) of this section.

X_{CO2} = Annual average mole fraction of CO_2 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(3) of this section.

Z_U = Fraction of the feed gas sent to an un-lit flare determined from both the total time the flare was unlit as determined by monitoring the pilot flame or combustion flame as specified in paragraph (n)(2) of this section and the volume of gas routed to the flare during periods when the flare was unlit as determined by the flow measurement required by paragraph (n)(1) of this section.

Z_L = Fraction of the feed gas sent to a burning flare (equal to $1 - Z_U$).

Y_j = Annual average mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(3) of this section.

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

(i) If you measure the gas flow at the flare inlet as specified in paragraph (n)(1)(i) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(3)(i) or (ii) of this section, then use those data in Equations W–19 and W–20 to calculate total emissions from the flare.

(ii) If you measure the flow from each source as specified in paragraph (n)(1)(ii) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(3)(i) or (ii) of this section, then sum the flows for each stream to calculate the total annual gas flow to the flare. Use that total annual flow with the annual average concentration of each constituent as calculated in paragraph (n)(3)(i) or (ii) of this section in Equations W–19 and W–20 to calculate total emissions from the flare.

(iii) If you measure the flow from each source as specified in paragraph (n)(1)(ii) of this section and you measure gas composition for the emission stream from each source as specified in paragraph (n)(3)(iii) or (iv) of this section, then calculate total emissions from the flare as specified in either paragraph (n)(5)(iii)(A) or (B) of this section.

(A) Use each set of stream-specific flow and annual average concentration data in Equations W–19 and W–20 to calculate stream-specific flared emissions for each stream, and then sum the results from each stream-specific calculation to calculate the total emissions from the flare.

(B) Sum the flows from each source to calculate the total gas flow into the flare and use the source-specific flows and source-specific annual average concentrations to determine flow-weighted annual average concentrations of CO_2 and hydrocarbon constituents in the combined gas stream into the flare. Use the calculated total gas flow and the calculated flow-weighted annual average concentrations for the inlet gas stream to the flare in Equations W–19 and W–20 to calculate the total emissions from the flare.

(iv) You may not combine measurement of the inlet gas flow to the flare as specified in paragraph (n)(1)(i) of this section with measurement of the gas composition of the streams from each source as specified in paragraph (n)(3)(iii) or (iv) of this section.

(6) *Convert volume at actual conditions to volume at standard conditions.* Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

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

(8) *Calculate N_2O emissions.* Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section. Determine higher heating values to use in Equation W–40 calculations as specified in paragraphs (n)(8)(i) through (iii) of this section, as applicable.

(i) If you measure composition of the inlet gas to the flare as specified in either paragraph (n)(3)(i) or (ii) of this section, then calculate a flare-specific higher heating value to use in Equation W–40 to calculate total N_2O emissions from the flare.

(ii) If you measure composition of the individual streams routed to the flare as specified in paragraph (n)(3)(iii) or (iv) of this section, and you calculate CH_4 and CO_2 emissions per stream as specified in paragraph (n)(5)(iii)(A) of this section, then calculate stream-specific higher heating values. Use the stream-specific higher heating values in separate stream-specific calculations of N_2O emissions and sum the resulting values to calculate the total N_2O emissions from the flare.

(iii) If you measure composition of the individual streams routed to the flare as specified in paragraph (n)(3)(iii) or (iv) of this section, and you calculate CH_4 and CO_2 emissions using flow-weighted annual average concentrations for the inlet gas to the flare as calculated according to paragraph (n)(5)(iii)(B) of this section, then either calculate higher heating values and N_2O emissions as specified in paragraph (n)(8)(ii) of this section, or calculate a flare-specific higher heating value using the calculated flow-weighted composition of the inlet gas to the flare, and use this flare-specific higher heating value to calculate the total N_2O emissions from the flare.

(9) *CEMS.* If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the flare, you must calculate CO_2 emissions for the flare using the CEMS. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack CO_2 emissions, you must also comply with all other requirements specified in paragraphs (n)(1) through (8) of this section, except that calculation of CO_2 emissions using

Equation W–20 in paragraph (n)(5) of this section is not required.

(10) *Disaggregation*. Using engineering calculations and best available data, disaggregate the total emissions from the flare as calculated in paragraphs (n)(7) and (8) of this section or paragraph (n)(9) of this section, as applicable, to each source type listed in paragraphs (n)(10)(i) through (viii) of this section, as applicable to the industry segment, that routed emissions to the flare.

(i) Acid gas removal units.

(ii) Dehydrators.

(iii) Completions and workovers with hydraulic fracturing.

(iv) Completions and workovers without hydraulic fracturing.

(v) Hydrocarbon liquids and produced water storage tanks.

(vi) Well testing.

(vii) Associated gas.

(viii) Other (collectively).

(o) *Centrifugal compressor venting*. If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10) of this section and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section. If emissions from a compressor source are routed to combustion, paragraphs (o)(1) through (11) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to a vapor recovery system, paragraphs (o)(1) through (11) of this section do not apply.

(1) * * *

(i) *Centrifugal compressor source as found measurements*. Measure venting from each compressor according to either paragraph (o)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (o)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (o)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

* * * * *

(2) *Methods for performing as found measurements from individual centrifugal compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section, and the volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section.

(i) For blowdown valves on compressors in operating-mode or in standby-pressurized-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

* * * * *

(ii) For wet seal oil degassing vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions, using one of the methods specified in paragraphs (o)(2)(ii)(A) through (C) of this section. You must quantitatively measure the volumetric flow for wet seal oil degassing vent; you may not use screening methods set forth in § 98.234(a) to screen for emissions for the wet seal oil degassing vent.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(iii) For dry seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions from each dry seal vent using one of the methods specified in paragraphs (o)(2)(iii)(A) through (D) of this section. If a compressor has more than one dry seal vent, determine the aggregate dry seal vent volumetric flow for the compressor as the sum of the volumetric flows determined for each dry seal vent on the compressor.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(D) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (o)(2)(iii)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the methods. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening dry seal vents.

(4) * * *

(ii) * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these methods, then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(i) Using Equation W–21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W–22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was not measured in the reporting year.

(iii) Using Equation W–23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section.

* * * * *

(8) * * *

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (o)(1)(i)(C), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate volumetric emissions from centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (o)(10)(i) through (iii), as applicable.

(i) For centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you must conduct measurements according to paragraphs (o)(10)(i)(A) and (B) of this section.

(A) You must conduct the volumetric emission measurements as required by § 60.5380b(a)(5) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct any additional volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section, and calculate emissions as specified in paragraphs (o)(6) through (9) of this section. Conduct all measurements required by this paragraph (o)(10)(i)(A) at the frequency specified by § 60.5380b(a)(4) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5380b(a)(4) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (o)(6)(ii) of this section.

(B) You must conduct measurements of compressors as specified in paragraph (o)(1)(i)(B) of this section such that at the end of each calendar year, you have taken measurements in not-operating-depressurized-mode over the last 3 consecutive calendar years for at least one-third of the compressors at your facility that are subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals.

(ii) For centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you may elect to conduct the volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section and perform calculations specified in paragraphs (o)(6) through (9) of this section.

(iii) For any centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraphs (o)(10)(i) and (ii) of this section do not apply, you must calculate atmospheric centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (o).

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

Where:

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

Count = Total number of centrifugal compressors that have wet seal oil degassing vents that are vented directly to the atmosphere.

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(9), you must calculate volumetric emissions as specified in paragraph (p)(10) of this section and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section. If emissions from a compressor source are routed to combustion, paragraphs (p)(1) through (11) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to a vapor recovery system, paragraphs (p)(1) through (11) of this section do not apply.

(1) * * *

(i) Reciprocating compressor source as found measurements. Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (p)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (p) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (p)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

* * * * *

(2) *Methods for performing as found measurements from individual reciprocating compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

* * * * *

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode or standby-pressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

* * * * *

(C) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraphs (p)(2)(ii)(A) and (B) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph (p)(2)(ii)(C), when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening or measuring rod packing emissions.

(iii) * * *

(A) You must use the methods described in § 98.234(a)(1) through (3) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening rod packing emissions.

* * * * *

(4) * * *

(ii) * * *

(C) A high volume sampler according to methods set forth in § 98.234(d).

* * * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraphs (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(ii) Using Equation W–27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

(iii) Using Equation W–28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

(8) * * *

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (o)(1)(i)(C), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate volumetric emissions from reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (p)(10)(i) through (iii) of this section, as applicable.

(i) For reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct measurements according to paragraphs (p)(10)(i)(A) and (B) of this section.

(A) You must conduct the volumetric emission measurements as required by § 60.5385b(b) and (c) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct any additional volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section, and calculate emissions as specified in paragraphs (p)(6) through (9) of this section. Conduct all measurements required by this paragraph (p)(10)(i)(A) at the frequency specified by § 60.5385b(a) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5385b(a) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (p)(6)(ii) of this section.

(B) You must conduct measurements of compressors as specified in paragraph (p)(1)(i)(B) of this section such that at the end of each calendar year, you have taken measurements in not-operating-depressurized-mode over the last 3 consecutive calendar years for at least one-third of the compressors at your facility that are subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(ii) For reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section and perform calculations specified in paragraphs (p)(6) through (9) of this section.

(iii) For any reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraphs (p)(10)(i) and (ii) of this section do not apply, you must calculate reciprocating compressor atmospheric venting of rod packing emissions using Equation W–29D of this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-29D)}$$

Where:

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

Count = Total number of reciprocating compressors with rod packing emissions vented directly to the atmosphere.

$EF_{i,s}$ = Emission factor for GHG_i. Use 2.13×10^5 standard cubic feet per year per compressor for CH_4 and 1.18×10^4 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) and (v) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (q) and only the count of these equipment must be reported.

(1) *Survey requirements*—(i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(ii) For the components listed in § 98.232(i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a) except § 98.234(a)(2)(ii) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iii) For the components listed in § 98.232(c)(21)(i), (e)(7) and (8), (f)(5) through (8), (g)(4), (g)(6) and (7), (h)(5), (h)(7) and (8), and (j)(10)(i) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iv) For the components listed in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) or (7), (h)(7) or (8), or (j)(10)(i), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) using the procedures in either paragraph (q)(2) or (3) of this section.

(B) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(e)(8), (f)(6) and (8), (g)(7), and (h)(8), then you must use the procedures in either paragraph (q)(2) or (3) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, for any elective survey under paragraph (q)(1)(iv) of this section, then you must survey the component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) using the emission calculation requirements in either paragraph (q)(2) or (3) of this section.

(v) For the components listed in § 98.232(d)(7), you must conduct surveys as specified in paragraphs (q)(1)(v)(A) and (B) of this section and you must calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(A) For the components listed in § 98.232(d)(7) that are not subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may use any of the leak detection methods listed in § 98.234(a).

(B) For the components listed in § 98.232(d)(7) that are subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must use either of the leak detection methods in § 98.234(a)(1)(iii) or (a)(2)(ii).

(vi) Except as provided in paragraph (q)(1)(vii) of this section, you must conduct at least one complete leak detection survey in a calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. Except as provided in paragraphs (q)(1)(vi)(A) through (G) of this section, a complete leak detection survey is a survey in which all equipment components required to be surveyed as specified in paragraphs (q)(1)(i) through (v) of this section are surveyed.

(A) For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(B) For components subject to the well site, centralized production facility, and compressor station fugitive emissions standards in § 60.5397b of this chapter, each survey conducted in accordance with the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(C) For components subject to the well site, centralized production facility, and compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the applicable approved state plan or applicable Federal plan in part 62 of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(D) For an onshore petroleum and natural gas production facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a single well-pad will be considered a complete leak detection survey for purposes of this section.

(E) For an onshore petroleum and natural gas gathering and boosting facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a gathering and boosting site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section.

(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.

(G) For natural gas distribution facilities that choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years as provided in paragraph (q)(1)(vii) of this section, a survey of all required components at the above grade transmission-distribution transfer stations monitored during the calendar year will be considered a complete leak detection survey for purposes of this section.

(vii) Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section. Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years "n," not exceeding a five-year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(2) *Calculation Method 1: Leaker emission factor calculation methodology.* If you elect not to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use this Calculation Method 1 for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (v) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section and the requirements specified in paragraphs (q)(2)(i) through (ix) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(1)(vii) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i \times EF_{sp} \times \sum_{z=1}^{x_p} T_{p,z} \times k \qquad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type "p" (in accordance with paragraphs (q)(1)(i) through (v) of this section) in standard ("s") cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type "p" detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor as specified in paragraphs (q)(2)(iii) through (x) of this section.

k = Factor to adjust for undetected leaks by respective leak detection method, where k equals 1.25 for the methods in § 98.234(q)(1), (3) and (5); k equals 1.55 for the method in § 98.234(q)(2)(i); and k equals 1.27 for the method in § 98.234(q)(2)(ii).

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; 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 onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH4 and 1.1×10^{-2} CO_2.

$T_{p,z}$ = The total time the surveyed component "z," component type "p," was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.*, not operating under pressure) using an engineering estimate based on best available data.

(i) The leak detection surveys selected for use in Equation W–30 must be conducted during the calendar year as indicated in paragraph (q)(1)(vi) and (vii) of this section, as applicable.

* * * * *

(iii) Onshore petroleum and natural gas production facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W–2 to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker factors for components in gas service listed in Table W–2 to this subpart.

(v) Onshore natural gas processing facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in table W–4 to this subpart.

(vi) Onshore natural gas transmission compression facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in table W–4 to this subpart.

(vii) Underground natural gas storage facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in table W–4 to this subpart.

(viii) LNG storage facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in table W–6 to this subpart.

(ix) LNG import and export facilities must, if available, use the site-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in table W–6 to this subpart.

(x) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in table W–6 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations.

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHGi. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHGi annually according to paragraph (q)(2)(x)(B) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \quad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type ''p'' during year ''y'' in standard (''s'') cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–6 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run ''w'' was operational, in hours during survey year ''y'' using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year ''y''.

y = Year of data included in emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(B) of this section.

n = Number of years of data, according to paragraph (q)(1)(vii) of this section, whose results are used to calculate emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(B) of this section.

(B) The emission factor ''$eFs,_{MR,i}$,'' based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous (n − 1) calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 is based on survey results from ''n'' years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, ''n_{new},'' in the new cycle is smaller than the number of years in the previous cycle, ''n,'' calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous (n_{new} − 1) calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(3) *Calculation Method 2: Leaker measurement methodology*. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (v) of this section, you may elect to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. If you elect to use this method, you must use this method for all components included in a complete leak survey and you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by the method of leak detection and component type as specified in paragraphs (q)(3)(i) through (vii) of this section.

(i) Determine the volumetric flow rate of each natural gas leak identified during the leak survey following the methods § 98.234(b) through (d), as appropriate for each leak identified. You do not need to use the same measurement method for each leak measured.

(ii) For each leak, calculate the volume of natural gas emitted as the product of the natural gas flow rate measured in paragraph (q)(3)(i) of this section and the duration of the leak. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year;

assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey. For each leaking component, account for time the component was not operational (*i.e.*, not operating under pressure) using an engineering estimate based on best available data.

(iii) For each leak, convert the volumetric emissions of natural gas determined in paragraph (q)(3)(ii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(iv) For each leak, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (q)(3)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each leak, convert the GHG volumetric emissions at standard conditions determined in paragraph (q)(3)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (q)(3)(v) of this section separately for each type of component required to be surveyed by the method used for the survey for which a leak was detected.

(vii) Multiply the total CO_2 and CH_4 mass emissions by survey method and component type determined in paragraph (q)(3)(vi) by the survey specific value for ''k'', the factor adjustment for undetected leaks, where k equals 1.25 for the methods in § 98.234(q)(1), (3) and (5); k equals 1.55 for the method in § 98.234(q)(2)(i); and k equals 1.27 for the method in § 98.234(q)(2)(ii).

(viii) For natural gas distribution facilities:

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHG_i using the methods as specified in paragraphs (q)(2)(x)(A) and (B) of this section, except use the GHG mass emissions calculated in paragraph (q)(3)(vi) of this section rather than the emissions calculated using Equation W–30.

(B) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated according to paragraph (q)(3)(vii)(A) of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(4) *Development of site-specific component-level leaker emission factors by leak detection method.* If you elect to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use the measurement values determined in accordance with paragraph (q)(3) of this section to calculate a site-specific component-level leaker emission factor by leak detection method as provided in paragraphs (q)(4)(i) through (iv) of this section.

(i) You must track the leak measurements made separately for each of the applicable components listed in paragraphs (q)(1)(i) through (v) of this section and by the leak detection method according to the following three bins.

(A) Method 21 as specified in § 98.234(a)(2)(i).

(B) Method 21 as specified in § 98.234(a)(2)(ii).

(C) Optical gas imaging (OGI) and other leak detection methods as specified in § 98.234(a)(1), (3), or (5).

(ii) You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a site-specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section (Calculation Method 1: Leaker emission factor calculation methodology).

(iii) Sum the volumetric flow rate of natural gas determined in accordance with paragraph (q)(3)(i) of this section for each leak by component type and leak detection method as specified in paragraph (q)(4)(i) of this section meeting the minimum number of measurement requirement in paragraph (q)(4)(ii) of this section.

(iv) Convert the volumetric flow rate of natural gas determined in paragraph (q)(4)(iii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(v) Determine the emission factor in units of standard cubic feet per hour component (scf/hr-component) by dividing the sum of the volumetric flow rate of natural gas determined in paragraph (q)(4)(iv) of this section by the total number of leak measurements for that component type and leak detection method combination.

(vi) You must update the emission factor determined in (q)(4)(v) of this section annually to include the results from all complete leak surveys for which leak measurement was performed during the reporting year in accordance with paragraph (q)(3) of this section.

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in § 98.232(c)(21)(ii), (f)(7), (g)(5), (h)(6), and (j)(10)(ii) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2) through (6), (j)(11), and (m)(3) through (5). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (r) and do not need to be reported. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (r) and only the count of these equipment must be reported. You must calculate emissions from all emission sources listed in this paragraph (r) using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \qquad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \quad \text{(Eq. W-32B)}$$

Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a major equipment (*e.g.*, wellhead, separator), component (*e.g.*, connector, open-ended line), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, gathering pipeline, transmission company interconnect metering-regulating station, farm tap and/or direct sale metering-regulating station, or transmission pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations.

$Count_e$ = Total number of the emission source type at the facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must count each major equipment piece listed in Table W–1 to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–3 to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count the: (1) Number of distribution services by material type; (2) miles of distribution mains by material type; (3) number of below grade transmission-distribution transfer stations; and (4) number of below grade metering-regulating stations; as listed in Table W–5 to this subpart. Onshore natural gas transmission pipeline facilities must count the following, as listed in Table W–5 to this subpart: (1) Miles of transmission pipelines by material type; (2) number of transmission company interconnect metering-regulating stations; and (3) number of farm tap and/or direct sale metering-regulating stations.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in tables W–1, W–3, and W–5 to this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W–31 of this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression, underground natural gas storage, and onshore natural gas transmission pipeline, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

(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 and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in table W–1 of this subpart. Major equipment associated with gas wells are considered gas service equipment in table W–1 of this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in table W–1 of this subpart. Major equipment associated with crude oil wells are considered crude service equipment in table W–1 of this subpart. Where facilities conduct EOR operations, the emission factor listed in table W–1 of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in table W–3 to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factors for LNG storage compressors in gas service listed in table W–5 to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factors for LNG terminal compressors in gas service listed in table W–5 to this subpart.

(6) Natural gas distribution facilities must use the appropriate methane emission factors as described in paragraphs (r)(6)(i) and (ii) of this section.

(i) Below grade transmission-distribution transfer stations, below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in table W–5 of this subpart to estimate emissions from components listed in § 98.232(i)(2), (4), (5), and (6), respectively.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W–31 for the components listed in § 98.232(i)(3). Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in § 98.236(r)(2)(v).

(7) Natural gas transmission pipeline facilities must use the appropriate default methane population emission factors listed in table W–5 of this subpart to estimate emissions from components listed in § 98.232(m)(3) through (5).

(s) *Offshore petroleum and natural gas production facilities*. Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified by BOEM in compliance with 30 CFR 550.302 through 304.

(1) Offshore production facilities that report to BOEM's emissions inventory shall report the same annual emissions as calculated and reported to BOEM as referenced in 30 CFR 550.302 through 304.

(i) For any reporting year that does not coincide with a BOEM emissions inventory data collection year, report the most recent published BOEM emissions inventory data referenced in 30 CFR 550.302 through 550.304. Adjust emissions based on the operating time for the facility relative to the operating time in the most recent published BOEM emissions inventory data.

(ii) As an alternative to the adjustment provisions in paragraph (s)(1)(i) of this section, you may use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 550.304 to calculate and report annual emissions.

(2) Offshore production facilities that do not report to BOEM's emissions inventory must use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 550.304 to calculate and report annual emissions.

(i) For any reporting year that does not coincide with a BOEM emissions inventory data collection year, you may report the most recent emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) As an alternative to the adjustment provisions in paragraph (s)(2)(i) of this section, you may use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 550.304 to calculate and report annual emissions.

(3) If BOEM discontinues or delays their data collection effort by more than 3 years, then offshore reporters shall once in every 3 years use the most recent BOEM data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEM jurisdiction that were not covered in the previous BOEM data collection cycle must use the most recent BOEM data collection and emissions estimation methods published by BOEM referenced in 30 CFR 550.302 through 550.304 to calculate and report emissions.

(t) * * *

(2) * * *

* * * * *

Z_a = Compressibility factor at actual conditions for GHG_i. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

* * * * *

(u) * * *

(2) * * *

(ii) *GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.* For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

* * * * *

(y) *Other large release events.* Calculate CO_2 and CH_4 emissions from other large release events as specified in paragraphs (y)(2) through (5) of this section for each release that meets or exceeds the applicable criteria in paragraph (y)(1) of this section. You are not required to measure every release from your facility, but if you have credible information that demonstrates the release meets or exceeds one of the thresholds or credible information that the release may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event.

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i) or (ii) of this section considering the entire event duration. The thresholds listed in paragraphs (y)(1)(i) or (ii) of this section are not limited to the emissions that occur within a given reporting year.

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that either:

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; or

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more.

(ii) For sources subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, a release that emits GHG at or above at least one of the thresholds listed in paragraphs (y)(1)(ii)(A) or (B) of this section. For a release meeting the criteria in either paragraph (y)(1)(ii)(A) or (B) of this section, you must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions calculated under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section, as applicable.

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section; or

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO_2e or more in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section.

(2) Estimate the total volume of gas released during the event in standard cubic feet and the methane emission rate at any point in time during the event in kilograms per hour using measurement data according to § 98.234(b), if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available according to paragraphs (y)(2)(i) through (v) of this section.

(i) The total volume of gas released must be estimated as the product of the measured or estimated average flow or release rate and the estimated event duration. For events for which information is available showing variable or decaying flow rates, you must calculate the maximum natural gas flow or release rate during the event and either determine a representative average release rate across the entire event or determine representative release rates for specific time periods within the event duration. If you elect to determine representative release rates for specific time periods within the event duration, calculate the volume of gas released for each time period within the event duration as the product of the representative release rate and the length of the corresponding time period and sum the volume of gas released across each of the time periods for the full duration of the event.

(ii) The start time of the event must be determined based on monitored process parameters. If monitored process parameters cannot identify the start of the event, the event must be assumed to start on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the rates specified in paragraph (y)(1) of this section or assumed to have a duration of 182 days, whichever duration is shorter.

(iii) The end time of the event must be the date of the confirmed repair or confirmed cessation of emissions.

(iv) For the purposes of paragraph (y)(2)(ii) of this section, ''monitoring or measurement survey'' includes any monitoring or measurement method in § 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at the thresholds specified in paragraph (y)(1).

(v) For events that span two different reporting years, calculate the portion of the event's volumetric emissions calculated according to paragraph (y)(2)(i) of this section that occurred in each reporting year considering only reporting year 2025 and later reporting years. For events with consistent flow or for which one average emissions rate is used, use the relative duration of the event within each reporting year to apportion the volume of gas released for each reporting year. For variable flow events for which the volume of gas released is estimated for separate time periods, sum the volume of gas released across each of the time periods within a given reporting year separately. If one of the time periods span two different reporting years, calculate the portion of the volumetric emissions calculated for that time period that applies to each reporting year based on the number of hours in that time period within each reporting year.

(3) Determine the composition of the gas released to the atmosphere using measurement data, if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available. In the event of an explosion or fire, where a portion of the natural gas may be combusted, estimate the composition of the gas released to the atmosphere considering the fraction of natural gas released directly to the atmosphere and the fraction of natural gas that was combusted by the explosion or fire during the release event. Assume a maximum combustion efficiency of 92 percent for natural gas that is combusted in an explosion or fire when estimating the CO_2 composition of the release. You may use different compositions for different periods within the duration if available information suggests composition varied during the release (*e.g.,* if a portion of the release occurred while fire was present and a portion of the release occurred when no fire was present).

(4) Calculate the GHG volumetric emissions using Equation W–35 in paragraph (u)(1) of this section.

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

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Except as specified in paragraphs (z)(6) and (7) of this section, calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment using the applicable method in paragraphs (z)(1) through (3) of this section according to the fuel combusted as specified in those paragraphs:

(1) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(1)(i) of this section, then calculate emissions according to paragraph (z)(1)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is listed in table C–1 of subpart C of this part or is a blend in which all fuels are listed in table C–1. If the fuel is natural gas or the blend contains natural gas, the natural gas must also meet the criteria of paragraphs (z)(1)(i)(A) and (B) of this section.

(A) The natural gas must be of pipeline quality specification.

(B) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(ii) For fuels listed in paragraph (z)(1)(i) of this section, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to any Tier listed in subpart C of this part, except that each natural gas-fired reciprocating internal combustion engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(5) of this section.

(2) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(2)(i) of this section, then calculate emissions according to paragraph (z)(2)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is natural gas that is not pipeline quality or it is a blend containing natural gas that is not pipeline quality with only fuels that are listed in table C–1. The natural gas must meet the criteria of paragraphs (z)(2)(i)(A) through (C) of this section.

(A) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(B) The natural gas must have a maximum CO_2 content of 1 percent by volume.

(C) The natural gas must have a minimum CH_4 content of 85 percent by volume.

(ii) For fuels listed in paragraph (z)(2)(i) of this section, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to Tier 2, Tier 3, or Tier 4 listed in subpart C of this part, except that each natural gas-fired reciprocating engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(5) of this section.

(3) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(3)(i) of this section, then calculate emissions according to paragraph (z)(3)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment does not meet the criteria of either paragraph (z)(1)(i) or (z)(2)(i) of this section. Examples include natural gas that is not of pipeline quality, natural gas that has a higher heating value of less than 950 Btu per standard cubic feet, and natural gas that is not pipeline quality and does not meet the composition criteria of either paragraph (z)(2)(i)(B) or (C) of this section. Other examples include field gas that does not meet the definition of natural gas in § 98.238 and blends containing field gas that does not meet the definition of natural gas in § 98.238.

(ii) For fuels listed in paragraph (z)(3)(i) of this section, calculate combustion emissions for each unit or group of units combusting the same fuel as follows:

(A) You may use company records to determine the volume of fuel combusted in the unit or group of units during the reporting year.

(B) If you have a continuous gas composition analyzer on fuel to the combustion unit(s), you must use these compositions for determining the concentration of each constituent in the flow of gas to the unit or group of units. If you do not have a continuous gas composition analyzer on gas to the combustion unit(s), you may use engineering estimates based on best available data to determine the concentration of each constituent in the flow of gas to the unit or group of units. Otherwise, you must use the appropriate gas compositions for each stream going to the combustion unit(s) as specified in paragraph (u)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations W–39A and W–39B of this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH_4} = V_a * (1-\eta) * Y_{CH_4} \qquad \text{(Eq. W-39B)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to the combustion unit or group of units in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 in gas sent to the combustion unit or group of units.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices that are not reciprocating internal combustion engines or gas turbines, a default of 0.995 can be used. For two-stroke lean-burn reciprocating internal combustion engines, a default of 0.953 must be used; for four-stroke lean-burn reciprocating internal combustion engines, a default of 0.962 must be used; for four-stroke rich-burn reciprocating internal combustion engines, a default of 0.997 must be used, and for gas turbines, a default of 0.999 must be used.

Y_j = Mole fraction of hydrocarbon constituent j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to the combustion unit or group of units.

R_j = Number of carbon atoms in the hydrocarbon constituent j in gas sent to the combustion unit or group of units; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

Y_{CH4} = Mole fraction of methane in gas sent to the combustion unit or group of units.

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

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

(F) Calculate N_2O mass emissions using Equation W–40 of this section.

$$Mass_{N_2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \qquad \text{(Eq. W-40)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Site-specific higher heating value of the fuel, mmBtu/unit of the fuel (in units consistent with the fuel quantity combusted).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) For each natural gas-fired reciprocating internal combustion engine or gas turbine calculating emissions according to paragraph (z)(1)(ii) or (z)(2)(ii) of this section, you must determine a CH_4 emission factor (kg CH_4/MMBtu) using one of the methods provided in paragraphs (z)(4)(i) through (iii) of this section. If you are required to or elect to use the method in paragraph (z)(4)(i) of this section, you must use the results of the performance test to determine the CH_4 emission factor.

(i) Conduct a performance test following the applicable procedures in § 98.234(i).

(ii) Original equipment manufacturer information, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the reciprocating internal combustion engine or gas turbine.

(iii) Applicable equipment type-specific emission factor from table W–7 of this subpart.

(5) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities that are calculated according to the procedures in either paragraph (z)(1)(ii) or (z)(2)(ii) of this section must be reported according to the requirements specified in § 98.236(z) rather than the reporting requirements specified in subpart C of this part.

(6) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each external fuel combustion unit.

(7) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these

emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

(aa) through (cc) [Reserved]

(dd) *Drilling mud degassing.* Calculate annual volumetric CH_4 emissions from the degassing of drilling mud using one of the calculation methods described in paragraphs (dd)(1) or (2) of this section. If you have taken mudlogging measurements, including gas trap-derived gas concentration and mud pumping rate, you must use Calculation Method 1 as described in paragraph (dd)(1) of this section. If you have not taken mudlogging measurements, you may use Calculation Method 2 as described in paragraph (dd)(2) of this section.

(1) *Calculation Method 1.* For each well in the sub-basin in which drilling mud was used during well drilling, you must calculate CH_4 emissions from drilling mud degassing applying an emissions rate derived from a representative well in the same sub-basin and at the same approximate total depth. You must follow the procedures specified in paragraph (dd)(1)(i) of this section to calculate CH_4 emissions for the representative well and follow the procedures in paragraphs (dd)(1)(ii) through (iv) of this section to calculate CH_4 emissions for every well drilled in the sub-basin and at the same approximate total depth.

(i) Calculate CH_4 emissions from mud degassing for one representative well in each sub-basin and at each approximate total depth. For the representative well, you must use mudlogging measurements, including gas trap derived gas concentration and mud pumping rate, taken during the reporting year. In the first year of reporting, you may use measurements from the prior reporting year if measurements from the current reporting year are not available. Use Equation W–41 of this section to calculate natural gas emissions from mud degassing at the representative well. You must identify and calculate CH_4 emissions for a new representative well for the sub-basin and same approximate total depth every 2 calendar years or on a more frequent basis. If a representative well is not available in the same sub-basin and at the same targeted approximate total depth, you may choose a well within the facility that is drilled into the same formation and at the same approximate total depth.

$$E_{s,CH_4,r} = MR_r \times T_r \times \frac{X_n}{1{,}000{,}000} \times GHG_{CH_4} \times 0.1337 \qquad \text{(Eq. W-41)}$$

Where:

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

MR_r = Average mud rate for the representative well, r, in gallons per minute.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes.

X_n = Concentration of natural gas in the drilling mud as measured by the gas trap, in parts per million.

GHG_{CH4} = Measured mole fraction of CH_4 in natural gas entrained in the drilling mud.

0.1337 = Conversion from gallons to standard cubic feet.

(ii) Calculate the emissions rate of CH_4 in standard cubic feet per minute from the representative well using Equation W–42 of this section.

$$ER_{s,CH_4,r} = \frac{E_{s,CH_4,r}}{T_r} \qquad \text{(Eq. W-42)}$$

Where:

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes.

(iii) Use Equation W–43 of this section to calculate emissions for any wells drilled in the same sub-basin and targeting the same approximate total depth in the reporting year.

$$E_{s,CH_4,p} = ER_{s,CH_4,r} \times T_p \qquad \text{(Eq. W-43)}$$

Where:

$E_{s,CH4,p}$ = Annual total CH_4 emissions from mud degassing for the well, p, in standard cubic feet.

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

T_p = Total time that drilling mud is circulated in the well, p, during the reporting year, in minutes.

(iv) Calculate CH_4 mass emissions using calculations in paragraph (v) of this section.

(2) *Calculation Method 2.* If you did not take mudlogging measurements, calculate emissions from mud degassing for each well using Equation W–44 of this section:

$$Mass_{CH_4,p} = EF_{CH_4} \times DD_p \qquad \text{(Eq. W-44)}$$

Where:

$Mass_{CH4,p}$ = Annual total CH_4 emissions for the well, p, in metric tons.

EF_{CH4} = Emission factor in metric tons CH_4 per drilling day. Use 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds.

DD_p = Total number of drilling days for the well, p. The first drilling day is the day that the borehole penetrated the first hydrocarbon-bearing zone and the last drilling day is the day drilling mud ceases to be circulated in the wellbore.

(ee) *Crankcase venting.* For reciprocating internal combustion engines or gas turbines, calculate annual CH_4 volumetric emissions from crankcase venting at standard conditions using Equation W–45 of this section:

$$E_{CH_4} = EF \times GHG_{CH_4} \times Count \times T \qquad \text{(Eq. W-45)}$$

Where:

E_{CH4} = Annual total volumetric emissions of CH_4 from crankcase venting on reciprocating internal combustion engines or gas turbines, in standard cubic feet.

EF = Emission factor for crankcase venting on reciprocating internal combustion engines or gas turbines, in standard cubic feet gas per hour per crankcase vent. Use 2.28 standard cubic feet gas per hour per crankcase vent.

GHG_{CH4} = Average concentration of CH_4 in the gas stream entering reciprocating internal combustion engines or gas turbines. If the concentration of CH_4 is unknown, use the concentration of CH_4 in the gas stream either using engineering estimates based on best available data or as defined in paragraph (u)(2) of this section.

Count = Total number of crankcase vents on reciprocating internal combustion engines or gas turbines.

T = Total operating hours per year for reciprocating internal combustion engines or gas turbines with crankcase vents.

■ 13. Amend § 98.234 by:

■ a. Revising the introductory text and paragraphs (a) and (d)(3);

■ b. Adding paragraph (d)(5);

■ c. Removing the text ''Equation W–41'' and ''Eq. W–41'' in paragraph (e) and adding in its place the text ''Equation W–46'' and ''Eq. W–46'', respectively;

■ d. Removing and reserving paragraphs (f) and (g); and

■ e. Adding paragraph (i).

The revisions and additions read as follows:

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 550.

(a) You must use any of the applicable methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) or screening survey(s) as specified in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii) or (q)(1)(v)(B). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection as specified in either paragraph (a)(1)(i), (ii), or (iii) of this section. You may use any of the methods as specified in paragraphs (a)(1)(i) through (iii) of this section unless you are required to use a specific method in § 98.233(q)(1).

(i) *Optical gas imaging instrument as specified in § 60.18 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the *Alternative work practice for monitoring equipment leaks*, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the minimum monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR part 60, subpart A, Table 1: *Detection Sensitivity Levels*; § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument from an applicable component is a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(ii) *Optical gas imaging instrument as specified in § 60.5397a of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(c)(3) and (7), and (e) of this chapter and paragraphs (a)(1)(ii)(A) through (C) of this section.

(A) For the purposes of this subpart, any visible emissions observed by the optical gas imaging instrument from a component required or elected to be monitored as specified in § 98.233(q)(1) is a leak.

(B) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(C) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

(iii) Optical gas imaging instrument as specified in appendix K to part 60 of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with appendix K to part 60, Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging. Any emissions detected by the optical gas imaging instrument from an applicable component is a leak.

(2) *Method 21.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter as specified in paragraph (a)(2)(i) or (ii) of this section. You may use either of the methods as specified in paragraphs (a)(2)(i) and (ii) of this section unless you are required to use a specific method in § 98.233(q)(1). You must survey all applicable source types at the facility needed to conduct a complete equipment leak survey as defined in § 98.233(q)(1). For the purposes of this subpart, the term ''fugitive emissions

component'' in § 60.5397a of this chapter and § 60.5397b of this chapter means ''component.''

(i) *Method 21 with a leak definition of 10,000 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 10,000 ppm or greater is measured for any applicable component, a leak is detected.

(ii) *Method 21 with a leak definition of 500 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 500 ppm or greater is measured for any applicable component, a leak is detected.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through-valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify through-valve leakage. For these acoustic stethoscope type devices, a leak is detected if an audible leak signal is observed or registered by the device. If the acoustic stethoscope type device is used as a screening to a measurement method and a leak is detected, the leak must be measured using any one of the methods specified in paragraphs (b) through (d) of this section.

* * * * *

(d) * * *

(3) For high volume samplers that output methane mass emissions, you must use the calculations in § 98.233(u) and (v) in reverse to determine the natural gas volumetric emissions at standard conditions. For high volume samplers that output methane volumetric flow in actual conditions, divide the volumetric methane flow rate by the mole fraction of methane in the natural gas according to the provisions in § 98.233(u) and estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

* * * * *

(5) If the measured methane flow exceeds the manufacturer's reported quantitation limit or if the measured natural gas flow determined as specified in paragraph (d)(3) of this section exceeds 70 percent of the manufacturer's reported maximum sampling flow rate, then the flow exceeds the capacity of the instrument and you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use calibrated bags according to paragraph (c) of this section to determine the leak or flow rate.

* * * * *

(i) You must use any of the applicable methods described in paragraphs (j)(1) through (3) of this section to conduct a performance test to determine the concentration of CH_4 in the exhaust gas. This concentration must be used to develop a CH_4 emission factor (kg/MMBtu) for estimating combustion slip from reciprocating internal combustion engines or gas turbines as specified in § 98.233(z)(4). Each performance test must be conducted within 10 percent of 100 percent peak load. You may not conduct performance tests during period of startup, shutdown or malfunction. You must conduct three separate test runs for each performance test. Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(1) EPA Method 18, Volatile Organic Compounds by Gas Chromatography in appendix A–6 to part 60 of this chapter.

(2) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in appendix A to part 63 of this chapter.

(3) ASTM D6348–12 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see § 98.7).

■ 14. Amend § 98.235 by revising paragraph (f) to read as follows:

§ 98.235 Procedures for estimating missing data.

* * * * *

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that start up new emission sources or acquire new sources from another facility that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly operating or newly acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

* * * * *

■ 15. Amend § 98.236 by:

■ a. Revising the introductory text and paragraph (a) introductory text, paragraphs (a)(1) through (8), (a)(9) introductory text, (a)(9)(iii), (vi), and (xii);

■ b. Adding paragraphs (a)(9)(xiii) and (xiv);

■ c. Revising paragraphs (a)(10), (b), (c), (d), (e), (f)(1) introductory text, (f)(1)(i) through (vii), and (f)(1)(xi) introductory text;

■ d. Adding paragraph (f)(1)(xi)(F);

■ e. Revising paragraph (f)(1)(xii) introductory text;

■ f. Adding paragraph (f)(1)(xii)(F);

■ g. Revising paragraphs (f)(2) introductory text and (f)(2)(i), (iii) through (v), (ix), and (x);

■ h. Adding paragraphs (f)(2)(xi) and (xii);

■ i. Revising paragraphs (g) introductory text, (g)(1) through (3), (g)(5)(i) through (iii), (g)(6) and (10), (h)(1) introductory text, (h)(1)(i), (iii), and (iv), (h)(2) introductory text, (h)(2)(i), (iii), and (iv);

■ j. Removing paragraphs (h)(2)(v) through (vii);

■ k. Revising paragraphs (h)(3) introductory text, (h)(3)(i), (h)(4), (i) introductory text, and (i)(1) introductory text;

■ l. Redesignating paragraphs (i)(1)(i) through (iii) as (i)(1)(ii) through (iv), respectively;

■ m. Adding new paragraph (i)(1)(i);

■ n. Revising paragraph (i)(2), (j), (k) introductory text, (k)(1), (k)(2) introductory text, and (k)(2)(i);

■ o. Removing paragraph (k)(3);

■ p. Revising paragraphs (l)(1) introductory text, (l)(1)(i) through (v), (l)(2), (l)(3) introductory text, (l)(3)(i) through (iv), (l)(4), (m) introductory text, and (m)(1) and (4) through (7);

■ q. Removing paragraph (m)(8);

■ r. Revising paragraphs (n), (o) introductory text, (o)(1), (o)(2)(i)(A) and (B), (o)(2)(ii)(A), (o)(2)(ii)(D) introductory text, (o)(2)(ii)(E), (o)(5), (p) introductory text, (p)(1), (p)(2)(ii)(A), (p)(2)(ii)(D) introductory text, (p)(2)(ii)(E), (p)(3)(ii) introductory text, (p)(5), (q) introductory text, (q)(1) and (2), (r) introductory text, (r)(1) and (3), (s), (x)(1), (y), (z), (aa) introductory text, (aa)(1) introductory text, (aa)(1)(i) introductory text, and (aa)(1)(i)(B) and (C);

■ s. Adding paragraph (aa)(1)(i)(D);

■ t. Revising paragraphs (aa)(1)(ii)(D) through (H);

■ u. Adding paragraph (aa)(1)(iii) and (iv);

■ v. Revising paragraphs (aa)(2), (aa)(3) introductory text, and (aa)(3)(i);

■ w. Adding paragraphs (aa)(3)(viii) and (ix);

■ x. Revising paragraphs (aa)(4)(i), (aa)(5)(ii), (aa)(6) and (7), and (aa)(8)(ii);

■ y. Removing and reserving paragraph (aa)(9);

■ z. Revising paragraphs (aa)(10) introductory text and (aa)(10)(ii) and (iv);

■ aa. Adding paragraph (aa)(10)(v);

■ bb. Revising paragraphs (aa)(11)(ii) through (iv), (bb) introductory text, and (cc); and

■ cc. Adding paragraphs (dd) and (ee).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in § 98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather than the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10) of this section, and each applicable emission source listed in paragraphs (b) through (z), (dd) and (ee) of this section.

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xxii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Liquids unloading.* Report the information specified in paragraph (f) of this section.

(vi) *Completions and workovers with hydraulic fracturing.* Report the information specified in paragraph (g) of this section.

(vii) *Completions and workovers without hydraulic fracturing.* Report the information specified in paragraph (h) of this section.

(viii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ix) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

(x) *Well testing.* Report the information specified in paragraph (l) of this section.

(xi) *Associated natural gas.* Report the information specified in paragraph (m) of this section.

(xii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(xiii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(xiv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(xv) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(xvi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xvii) *EOR injection pumps.* Report the information specified in paragraph (w) of this section.

(xviii) *EOR hydrocarbon liquids.* Report the information specified in paragraph (x) of this section.

(xix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xx) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(xxi) *Drilling mud degassing.* Report the information specified in paragraph (dd) of this section.

(xxii) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(2) *Offshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(2)(i) and (ii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Offshore petroleum and natural gas production.* Report the information specified in paragraph (s) of this section.

(ii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(iii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iv) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(v) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

(vi) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(viii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(ix) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(x) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents.* Report the information specified in paragraph (ee) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (x) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Condensate storage tanks.* Report the information specified in paragraph (k) of this section.

(v) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vi) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(viii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(ix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(x) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Condensate storage tanks.* Report the information specified in paragraph (k) of this section.

(v) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vi) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(viii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(ix) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(x) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iv) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(v) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vi) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(vii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iv) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(v) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vi) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(iv) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(v) *Other large release events.* Report the information specified in paragraph (y) of this section.

(vi) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(vii) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xiv) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(iii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

* * * * *

(vi) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

* * * * *

(xii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xiii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(xiv) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(10) *Onshore natural gas transmission pipeline.* For the equipment/activities specified in paragraphs (a)(10)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(iii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(b) *Natural gas pneumatic devices.* You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (5) of this section, as applicable. You must report the information specified in paragraphs (b)(1) through (5) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas pneumatic devices as specified in paragraphs (b)(2)(i) through (vii) of this section, as applicable. If a natural gas pneumatic device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then include the device in each of the applicable counts specified in paragraphs (b)(2)(ii) through (vii) of this section.

(i) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(4) through (6).

(ii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere, determined according to § 98.233(a)(4) through (6).

(iii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) routed to a flare, combustion, or vapor recovery system.

(iv) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1).

(v) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2).

(vi) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3).

(vii) If the reported values in paragraphs (b)(2)(i) through (vi) of this section are estimated values determined according to § 98.233(a)(5), then you must report the information specified in paragraphs (b)(2)(vii)(A) through (C) of this section.

(A) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vi) of this section that are counted.

(B) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vi) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(3) For natural gas pneumatic devices for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1), report the information in paragraphs (b)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) downstream of the flow monitor.

(iv) An indication of whether a natural gas driven pneumatic pump is also downstream of the flow monitor.

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(4) If you used Calculation Method 2 according to § 98.233(a)(2), report the information in paragraphs (b)(4)(i) through (vii) of this section, as applicable.

(i) The number of years used in the current measurement cycle.

(ii) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities:

(A) Indicate whether the emissions from the natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were measured during the reporting year or if the emissions were calculated using Equation W–1B.

(B) If the natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were measured during the reporting year, indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(C) If the emissions from natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were calculated using Equation W–1B, report the following information for each type of natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(*1*) The value of the emissions factor for the reporting year as calculated using Equation W–1A (in scf/hour/device).

(*2*) The total number of natural gas pneumatic devices measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of ''$\Sigma_{y=1}{}^{n}$ $Count_{t,y}$'' in Equation W–1A of this subpart).

(*3*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (*i.e.,* ''$Count_t$'' in Equation W–1B).

(4) The average estimated number of hours in the operating year the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in Equation W–1B of this subpart).

(iii) For onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities:

(A) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler) to measure the emissions from natural gas pneumatic devices at this facility.

(B) Indicate whether the emissions from any natural gas pneumatic devices at this facility were calculated using Equation W–1B.

(C) If the emissions from any natural gas pneumatic devices at this facility were calculated using Equation W–1B, report the following information for each type of natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(*1*) The value of the emission factor for the reporting year as calculated using Equation W–1A (in scf/hour/device).

(*2*) The total number of natural gas pneumatic devices measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of ''$\Sigma_{y=1}^{n}$ $Count_{t,y}$'' in Equation W–1A of this subpart).

(*3*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (*i.e.,* ''$Count_t$'' in Equation W–1B of this subpart).

(4) The average estimated number of hours in the operating year the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in Equation W–1B of this subpart).

(iv) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii). Enter 0 if the natural gas pneumatic devices at this well-pad or gathering and boosting were not monitored during the reporting year.

(v) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii). Enter 0 if the devices at this well-pad or gathering and boosting were not monitored during the reporting year.

(vi) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this well-pad, gathering and boosting site, or facility were monitored during the reporting year.

(vii) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this well-pad, gathering and boosting site, or facility were monitored during the reporting year.

(5) If you used Calculation Method 3 according to § 98.233(a)(3), report the information in paragraphs (b)(5)(i) through (vi) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices:

(A) Indicate whether you measured emissions according to § 98.233(a)(3)(i)(A) or used default emission factors according to § 98.233(a)(3)(i)(B) to calculate emissions from your continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere at this well-pad, gathering and boosting site, or facility, as applicable.

(B) If measurements were made according to § 98.233(a)(3)(i)(A), indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(C) If default emission factors were used according to § 98.233(a)(3)(i)(B) to calculate emissions, report the following information for each type of applicable natural gas pneumatic device (continuous low bleed and continuous high bleed).

(*1*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (''$Count_t$'' in Equation W–1B of this subpart).

(*2*) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in Equation W–1B of this subpart).

(ii) The number of years used in the current monitoring cycle for intermittent bleed pneumatic devices.

(iii) For intermittent bleed natural gas pneumatic devices at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities:

(A) Indicate whether the emissions from intermittent bleed natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were monitored during the reporting year and calculated using Equation W–1C of this subpart or if the emissions were calculated using Equation W–1D of this subpart.

(B) If the natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were monitored during the reporting year, indicate the primary monitoring method used (OGI; Method 21 at 10,000 ppm; Method 21 at 500 ppm; or infrared laser beam) and the number of complete monitoring surveys conducted at the well-pad or gathering and boosting site.

(C) If the emissions from intermittent bleed natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were calculated using Equation W–1C of this subpart, report the following information:

(*1*) The total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''x'' in Equation W–1C of this subpart).

(*2*) Average time the intermittent bleed natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of ''$T_{m,z}$'' in Equation W–1C of this subpart).

(*3*) The total number of intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''Count'' in Equation W–1C of this subpart).

(*4*) Average time the intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1C of this subpart).

(D) If the emissions from intermittent bleed natural gas pneumatic devices at this well-pad or gathering and boosting site, as applicable, were calculated using Equation W–1D of this subpart, report the following information:

(*1*) Total number of intermittent bleed natural gas pneumatic devices that were not surveyed during the year at the well-pad or gathering and boosting site (''$Count_C$'' in Equation W–1D of this subpart as applied to the well-pad or gathering and boosting site).

(*2*) Total number the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere facility-wide that were monitored during the reporting year and identified as malfunctioning as determined according to § 98.233(a)(3)(iv)(B) (''$Count_B$'' in Equation W–1D of this subpart).

(*3*) Total number the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere facility-wide that were monitored during the reporting year as determined according to § 98.233(a)(3)(iv)(A) (''$Count_A$'' in Equation W–1D of this subpart).

(*4*) Average time, in hours, the intermittent bleed natural gas pneumatic devices that were not monitored but during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1D of this subpart).

(iv) For intermittent bleed natural gas pneumatic devices at onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities:

(A) Indicate the primary monitoring method used (OGI; Method 21 at 10,000 ppm; Method 21 at 500 ppm, or infrared laser beam) and the number of complete monitoring surveys conducted at the facility.

(B) The total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''x'' in Equation W–1C of this subpart).

(C) Average time the intermittent bleed natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of ''$T_{m,z}$'' in Equation W–1C of this subpart).

(D) The total number of intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''Count'' in Equation W–1C of this subpart).

(E) Average time the intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1C of this subpart).

(F) If the emissions from some of the intermittent bleed natural gas pneumatic devices at this facility were calculated using Equation W–1D of this subpart, report the following information:

(*1*) Total number of intermittent bleed natural gas pneumatic devices that were not surveyed during the year at the facility (''$Count_C$'' in Equation W–1D of this subpart).

(*2*) Total number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere facility-wide that were monitored during the reporting year and identified as malfunctioning as determined according to § 98.233(a)(3)(iv)(B) (''$Count_B$'' in Equation W–1D of this subpart).

(*3*) Total number the number of unique intermittent bleed natural gas pneumatic devices vented directly to the atmosphere facility-wide that were monitored during the reporting year as determined according to § 98.233(a)(3)(iv)(A) (''$Count_A$'' in Equation W–1D of this subpart).

(*4*) Average time, in hours, the intermittent bleed natural gas pneumatic devices that were not monitored but during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1D of this subpart).

(v) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(vi) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (7) of this section. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then include the pump in each of the counts specified in paragraphs (c)(2) through (4) of this section. You must report the information specified in paragraphs (c)(1) through (7) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production) and each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas driven pneumatic pumps as specified in paragraphs (c)(2)(i) through (vi) of this section, as applicable. If a natural gas driven pneumatic pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then include the device in each of the applicable counts specified in paragraphs (c)(2)(ii) through (vi) of this section.

(i) Count of natural gas driven pneumatic pumps.

(ii) Count of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year.

(iii) Count of natural gas driven pneumatic pumps routed to a flare, combustion, or vapor recovery system at any point during the year.

(iv) Count of natural gas driven pneumatic pumps vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(c)(1).

(v) Count of natural gas driven pneumatic pumps vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(c)(2).

(vi) Count of natural gas driven pneumatic pumps vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(c)(3).

(3) For natural gas driven pneumatic pumps for which emissions were calculated using Calculation Method 1 according to § 98.233(c)(1), report the information in paragraphs (c)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas driven pneumatic pumps downstream of the flow monitor.

(iv) An indication of whether any natural gas pneumatic devices are also downstream of the monitoring location.

(v) Annual CO_2 emissions, in metric tons CO_2, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(4) If you used Calculation Method 2 according to § 98.233(c)(2), report the information in paragraphs (c)(4)(i) through (vi) of this section, as applicable.

(i) The number of years used in the current measurement cycle.

(ii) Indicate whether the emissions from the pneumatic pumps at this well-pad or gathering and boosting site, as applicable, were measured during the reporting year or if the emissions were calculated using Equation W–2C.

(A) If the pneumatic pumps at this well-pad or gathering and boosting site, as applicable, were measured during the reporting year, indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(B) If the emissions from pneumatic pumps at this well-pad or gathering and boosting site, as applicable, were calculated using Equation W–2C, report the following information:

(*1*) The value of the emissions factor for the reporting year as calculated using Equation W–2B (in scf/hour/pump).

(*2*) The total number of pumps measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of ''$\Sigma^{n}_{y=1}$ $Count_y$'' term used in Equation W–2B).

(*3*) Total number of natural gas driven pneumatic pumps that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(c)(1) or (c)(2)(iii) (*i.e.,* ''Count'' in Equation W–2B).

(*4*) The average estimated number of hours in the operating year the pumps were pumping liquid (*i.e.*, ''T'' in Equation W–2C).

(iii) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(iv) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(v) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(vi) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(5) If you used Calculation Method 3 according to § 98.233(c)(3), report the information in paragraphs (c)(5)(i) through (iii) of this section for the natural gas driven pneumatic pumps subject to Calculation Method 3.

(i) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were pumping liquid (''T'' in Equation W–2C of this subpart).

(ii) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(3).

(iii) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(3).

(d) *Acid gas removal units and nitrogen removal units.* You must indicate whether your facility has any acid gas removal units or nitrogen removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. For any acid gas removal units or nitrogen removal units that vent directly to the atmosphere or to a sulfur recovery plant, you must report the information specified in paragraphs (d)(1) and (2) of this section. For acid gas removal units or nitrogen removal units that were routed to a flare or routed to an engine for the entire year, you must only report the information specified in paragraph (d)(1)(i) through (iv) and (x) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (x) of this section for each acid gas removal unit or nitrogen removal unit, as applicable.

(i) A unique name or ID number for the acid gas removal unit or nitrogen removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit or nitrogen removal unit for each location it operates at in a given year.

(ii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to a flare, and if so, whether it was routed for the entire year or only part of the year.

(iii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to combustion, and if so, whether it was routed for the entire year or only part of the year.

(iv) Total feed rate entering the acid gas removal unit or nitrogen removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(v) If the acid gas removal unit or nitrogen removal unit was routed to a flare or to combustion for only part of the year, the feed rate entering the acid gas removal unit or nitrogen removal unit during the portion of the year that the emissions were vented directly to the atmosphere, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(vi) The calculation method used to calculate CO_2 and CH_4 emissions from the acid gas removal unit or to calculate CH_4 emissions from the nitrogen removal unit, as specified in § 98.233(d).

(vii) Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in § 98.233(d)(11). If any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO_2, in metric tons CO_2, that was recovered and transferred outside the facility under subpart PP of this part.

(viii) Annual CO_2 emissions, in metric tons CO_2, vented directly to the atmosphere from the acid gas removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(10) and (11).

(ix) Annual CH_4 emissions, in metric tons CH_4, vented directly to the atmosphere from the acid gas removal unit or nitrogen removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(10) and (11).

(x) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit or nitrogen removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit and Calculation Method 2 as specified in § 98.233(d) to calculate CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) through (C) of this section, as applicable.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit.

(C) Annual volume of gas vented from the acid gas removal unit or nitrogen removal unit, in cubic feet.

(D) The temperature that corresponds to the reported annual volume of gas vented from the unit, in degrees Fahrenheit. If the annual volume of gas vented is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(E) The pressure that corresponds to the reported annual volume of gas vented from the unit, in pounds per square inch absolute. If the annual volume of gas vented is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(ii) If you used Calculation Method 3 as specified in § 98.233(d) to calculate

CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (M) of this section, as applicable depending on the equation used.

(A) Indicate which equation was used (Equation W–4A, W–4B, or W–4C).

(B) Annual average volumetric fraction of CO_2 in the natural gas flowing out of the acid gas removal unit, as specified in Equation W–4A, Equation W–4B, or Equation W–4C of this subpart.

(C) Annual average volumetric fraction of CO_2 content in natural gas flowing into the acid gas removal unit, as specified in Equation W–4A, Equation W–4B, or Equation W–4C of this subpart.

(D) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit, as specified in Equation W–4A or Equation W–4B of this subpart.

(E) Annual average volumetric fraction of CH_4 in the natural gas flowing out of the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A, Equation W–4B, or Equation W–4C of this subpart.

(F) Annual average volumetric fraction of CH_4 content in natural gas flowing into the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A, Equation W–4B, or Equation W–4C of this subpart.

(G) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A or Equation W–4B of this subpart.

(H) The total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A or Equation W–4C of this subpart, in cubic feet at actual conditions.

(I) The temperature that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A or Equation W–4C of this subpart, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(J) The pressure that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4A or Equation W–4C of this subpart, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(K) The total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4B or Equation W–4C of this subpart, in cubic feet at actual conditions.

(L) The temperature that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4B or Equation W–4C of this subpart, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(M) The pressure that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in Equation W–4B or Equation W–4C of this subpart, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(iii) If you used Calculation Method 4 as specified in § 98.233(d) to calculate CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (N) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Annual average natural gas feed temperature, in degrees Fahrenheit.

(C) Annual average natural gas feed pressure, in pounds per square inch.

(D) Annual average natural gas feed flow rate, in standard cubic feet per minute.

(E) Annual average acid gas content of the feed natural gas, in mole percent.

(F) Annual average acid gas content of the outlet natural gas, in mole percent.

(G) Annual average methane content of the feed natural gas, in mole percent.

(H) Annual average methane content of the outlet natural gas, in mole percent.

(I) Total annual unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(J) Annual average exit temperature of the natural gas, in degrees Fahrenheit.

(K) Annual average solvent pressure, in pounds per square inch.

(L) Annual average solvent temperature, in degrees Fahrenheit.

(M) Annual average solvent circulation rate, in gallons per minute.

(N) Solvent type used for the majority of the year, from one of the following options: Selexol™, Rectisol®, Purisol™, Fluor Solvent, Benfield™, 20 wt% MEA, 30 wt% MEA, 40 wt% MDEA, 50 wt% MDEA, and other (specify).

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators for which you calculated emissions using Calculation Method 1 according to § 98.233(e)(1), glycol dehydrators for which you calculated emissions using Calculation Method 2 according to § 98.233(e)(2), and dehydrators that use desiccant. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3) of this section.

(1) For each glycol dehydrator for which you calculated emissions using Calculation Method 1 (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Annual average dehydrator feed natural gas flow rate, in million standard cubic feet per day.

(iii) Annual average dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Annual average dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (*e.g.,* natural gas pneumatic, air pneumatic, or electric).

(vi) Annual average dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripping gas is used in dehydrator.

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

(x) Total time the dehydrator is operating during the year, in hours.

(xi) Annual average temperature of the wet natural gas at the absorber inlet, in degrees Fahrenheit.

(xii) Annual average pressure of the wet natural gas at the absorber inlet, in pounds per square inch gauge.

(xiii) Annual average mole fraction of CH_4 in wet natural gas.

(xiv) Annual average mole fraction of CO_2 in wet natural gas.

(xv) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).(xvi) If a flash tank separator is used in the dehydrator, then you must report the information specified in paragraphs (e)(1)(xvi)(A) through (F) of this section for the emissions from the flash tank vent, as applicable. If flash tank emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvi)(G) through (I) of this section for the combusted emissions from the flash tank vent.

(A) Whether any flash gas emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(B) Annual CO_2 emissions, in metric tons CO_2, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(4).

(C) Annual CH_4 emissions, in metric tons CH_4, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(4).

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes was monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvi)(E) and (F) and (e)(1)(xvi)(H) and (I) of this section do not apply.

(H) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the flash tank combusted by a burning regenerator firebox/fire tubes.

(xvii) Report the information specified in paragraphs (e)(1)(xvii)(A) through (F) of this section for the emissions from the still vent, as applicable. If still vent emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvii)(G) through (I) of this section for the combusted emissions from the still vent.

(A) Whether any still vent emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(B) Annual CO_2 emissions, in metric tons CO_2, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1), and, if applicable, (e)(4).

(C) Annual CH_4 emissions, in metric tons CH_4, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(4).

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes was monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvii)(E) and (F) and (e)(1)(xvii)(H) and (I) of this section do not apply.

(H) Total volume of gas from the still vent to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the still vent combusted by a burning regenerator firebox/fire tubes.

(xviii) Name of the software package used.

(2) You must report the information specified in paragraphs (e)(2)(i) through (vi) of this section for all glycol dehydrators with an annual average daily natural gas throughput greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day for which you calculated emissions using Calculation Method 2 (as specified in § 98.233(e)(2)) at the facility, well-pad, or gathering and boosting site.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of dehydrators at the facility, well-pad, or gathering and boosting site for which you calculated emissions using Calculation Method 2.

(iii) Whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(iv) Whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were routed to each type of control device.

(v) Whether any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(v)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to regenerator firebox/fire tubes.

(B) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(vi) For dehydrator emissions that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(vi)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(ii) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(ii) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in § 98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (vi) of this section for the entire facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Count of desiccant dehydrators that had one or more openings during the calendar year at the facility, well-pad, or gathering and boosting site for which you calculated emissions using Calculation Method 3 as specified in paragraphs (e)(3)(ii)(A) through (C) of this section.

(A) The total number of opened desiccant dehydrators.

(B) The number of opened desiccant dehydrators that used deliquescing desiccant (e.g., calcium chloride or lithium chloride).

(C) The number of opened desiccant dehydrators that used regenerative desiccant (e.g., molecular sieves, activated alumina, or silica gel).

(iii) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section, total physical volume of all opened dehydrator vessels.

(iv) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section, total number of dehydrator openings in the calendar year.

(v) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section, whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(vi) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section, whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were routed to each type of control device.

(vii) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section, whether any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(3)(vii)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to regenerator firebox/fire tubes.

(B) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(viii) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii)(A) of this section that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(3)(viii)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(ii) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3) and, if applicable, (e)(4), and summing for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(ii) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3), and, if applicable, (e)(4), and summing for all such dehydrators.

(f) * * *

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells by unloading type combination (with or without plunger lifts, automated or manual unloading).

(i) Well ID number.

(ii) Well tubing diameter and pressure group ID.

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloading).

(iv) [Reserved]

(v) Indicate whether the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time the well was vented (''Tp'' from Equation W–7A or W–7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented directly to the atmosphere for the well.

* * * * *

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (F) of this section for each individual well not using a plunger lift that was tested during the year.

* * * * *

(F) Unloading type (automated or manual).

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (F) of this section for each individual well using a plunger lift that was tested during the year.

* * * * *

(F) Unloading type (automated or manual).

(2) For each well for which you used Calculation Method 2 or 3 (as specified in § 93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in paragraphs (f)(2)(i) through (xii) of this section. Report information separately for each calculation method and unloading type combination (with or without plunger lifts, automated or manual unloadings).

(i) Well ID number.

* * * * *

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloadings).

(iv) [Reserved]

(v) Cumulative number of unloadings vented directly to the atmosphere for the well.

* * * * *

(ix) Average flow-line rate of gas (average of ''SFR_p'' from Equation W–8 or W–9 of this subpart, as applicable), at standard conditions in cubic feet per hour.

(x) Cumulative amount of time that wells were left open to the atmosphere during unloading events (sum of ''$HR_{p,q}$'' from Equation W–8 or W–9 of this subpart, as applicable), in hours.

(xi) For each well without plunger lifts, the information in paragraphs (f)(2)(xi)(A) through (D) of this section.

(A) Internal casing diameter (''CD_p'' from Equation W–8 of this subpart), in inches.

(B) Well depth (''WD_p'' from Equation W–8 of this subpart), in feet.

(C) Shut-in pressure, surface pressure, or casing pressure (''SP_p'' from Equation W–8 of this subpart), in pounds per square inch absolute.

(D) The most recent calendar year Calculation Method 1 was used to calculate emissions from well venting for liquids unloading for wells without plunger lifts of the same sub-basin, well tubing diameter group and pressure group combination.

(xii) For wells with plunger lifts, the information in paragraphs (f)(2)(xiii)(A) through (D) of this section.

(A) Internal tubing diameter (''TD_p'' from Equation W–9 of this subpart), in inches.

(B) Tubing depth (''WD_p'' from Equation W–9 of this subpart), in feet.

(C) Flow line pressure (''SP_p'' from Equation W–9 of this subpart), in pounds per square inch absolute.

(D) The most recent calendar year Calculation Method 1 was used to calculate emissions from well venting for liquids unloading for the wells with plunger lifts in the same sub-basin, well tubing diameter group and pressure group combination.

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year that vented directly to the atmosphere, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each well. If your facility had well completions or workovers with hydraulic fracturing during the year that only routed to flares, then you must report the information specified in paragraphs (g)(1) through (3) of this section, for each well. Report information separately for completions and workovers.

(1) Well ID number.

(2) Well type combination (horizontal or vertical, flared or vented, reduced emission completion or not a reduced emission completion, gas well or oil well).

(3) Number of completions or workovers for each well.

* * * * *

(5) * * *

(i) Cumulative gas flowback time, in hours, for all completions or workovers at the well from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of ''$T_{p,i}$'' and sum of ''$T_{p,s}$'' values used in Equation W–10A of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total number of hours of flowback from the well during completions or workovers.

(ii) If the well is a measured well for the sub-basin and well-type combination, the flowback rate, in standard cubic feet per hour (average of ''$FR_{s,p}$'' values used in Equation W–12A of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that can be used for the measurement in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured flowback rate(s) during well completion or workover for the well.

(iii) If you used Equation W–12C of § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(6)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that can be used for the measurement in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the gas to oil ratio for the well.

(B) Volume of oil produced during the first 30 days of production after completion of the newly drilled well or well workover using hydraulic fracturing, in barrels (''V_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that can be used for the measurement in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced during the first 30 days of production after well completion or workover for the well.

(6) If you used Equation W–10B of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) and (ii) of this section.

(i) Vented natural gas volume, in standard cubic feet (''$FV_{s,p}$'' in Equation W–10B of § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour (''$FR_{p,i}$'' in Equation W–10B of § 98.233).

* * * * *

(10) Indicate whether the completion(s) or workover(s) included flared emissions that are reported according to paragraph (n) of this section in addition to the vented emissions reported under paragraphs (g)(8) and (9) of this section.

(h) * * *

(1) For each well with one or more gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Well ID number.

* * * * *

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions without hydraulic fracturing (''T_p'' for completions that vented directly to the atmosphere as used in Equation W–13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing without flaring, in standard cubic feet per hour (''V_p'' in Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that can be used for the measurement in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average daily gas production rate during completions for the well.

* * * * *

(2) For each well with one or more gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Well ID number.

* * * * *

(iii) Total number of hours that gas vented to a flare during venting for all completions without hydraulic fracturing (the sum of all ''T_p'' for completions that vented to a flare from Equation W–13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing with flaring, in standard cubic feet per hour (the average of all ''V_p'' from Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that can be used for the measurement in the same sub-basin and well type combination are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average daily gas production rate during completions for the well.

(3) For each well with one or more gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Well ID number.

* * * * *

(4) For each well with one or more gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) and (ii) of this section.

(i) Well ID number.

(ii) Number of workovers that flared gas.

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section. You must report the information specified in paragraphs (i)(1) through (3) of this section, as applicable, for each well-pad (for onshore production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2)(iv)(A) for onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iv) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iv) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2)(iv)(B) for the natural gas distribution or onshore natural gas transmission pipeline segments, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iv) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iv) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(2) *Report by flow meter.* If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to § 98.233(i)(3), then you must report the information specified in paragraphs (i)(2)(i) through (iii) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Annual CO_2 emissions from all blowdown vent stacks for which emissions were calculated using flow meters, in metric tons CO_2 (the sum of all CO_2 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

(iii) Annual CH_4 emissions from all blowdown vent stacks at the facility, well-pad, or gathering and boosting site for which emissions were calculated using flow meters, in metric tons CH_4, (the sum of all CH_4 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

* * * * *

(j) *Hydrocarbon liquids and produced water storage tanks.* You must indicate whether your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage tanks. If your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric pressure storage tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each well-pad (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) and by calculation method and liquid type, as applicable. Onshore petroleum and natural gas gathering and boosting and onshore natural gas processing facilities do not report the information specified in paragraph (j)(1)(ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual hydrocarbon liquids or produced water volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable atmospheric pressure storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids or produced water production flowing to gas-liquid separators or direct to atmospheric pressure storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total volume of hydrocarbon liquids or produced water from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average well, gas-liquid separator, or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average well, gas-liquid separator, or non-separator equipment pressure, in pounds per square inch gauge.

(vi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, the average sales oil or stabilized hydrocarbon liquids API gravity, in degrees.

(vii) For atmospheric pressure storage tanks receiving hydrocarbon liquids, the flow-weighted average concentration (mole fraction) of CO_2 in flash gas from atmospheric pressure storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(viii) The flow-weighted average concentration (mole fraction) of CH_4 in flash gas from atmospheric pressure storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(ix) The number of wells sending hydrocarbon liquids or produced water to gas-liquid separators or directly to atmospheric pressure storage tanks.

(x) Count of atmospheric pressure storage tanks specified in paragraphs (j)(1)(x)(A) through (F) of this section.

(A) The number of fixed roof atmospheric pressure storage tanks.

(B) The number of floating roof atmospheric pressure storage tanks.

(C) The number of atmospheric pressure storage tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system and/or one or more flares at any point during the reporting year.

(D) The number of atmospheric pressure storage tanks that routed emissions to a vapor recovery system at any point during the reporting year.

(E) The number of atmospheric pressure storage tanks that routed emissions to one or more flares at any point during the reporting year.

(F) The number of atmospheric pressure storage tanks in paragraph (j)(1)(x)(D) or (E) of this section that had an open or not properly seated thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(xi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xii) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xiii) For the atmospheric pressure storage tanks receiving hydrocarbon liquids identified in paragraphs (j)(1)(x)(D) of this section, total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(xiv) For the atmospheric pressure storage tanks identified in paragraphs (j)(1)(x)(D) of this section, total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(xv) For the atmospheric pressure storage tanks identified in paragraph (j)(1)(x)(F) of this section, the total volume of gas vented through open or not properly seated thief hatches, in scf, during periods while the storage tanks were also routing emissions to vapor recovery systems and/or flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (H) of this section, at the facility level, for atmospheric pressure storage tanks where emissions were calculated using Calculation Method 3 of § 98.233(j).

(A) The total annual hydrocarbon liquids throughput that is sent to all atmospheric pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids production that send hydrocarbon liquids to atmospheric pressure storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total annual hydrocarbon liquids throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) The total annual produced water throughput that is sent to all atmospheric pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels, specified in paragraphs (j)(2)(i)(B)(*1*) through (*3*) of this section. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin flowing to gas-liquid separators or direct to atmospheric pressure storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total annual volume of produced water from all wells as specified in paragraphs (j)(2)(i)(B)(*1*) through (*3*) of this section and the well ID number(s) for the well(s) included in these volumes.

(*1*) Total volume of produced water with pressure less than or equal to 50 psi.

(*2*) Total volume of produced water with pressure greater than 50 psi and less than or equal to 250 psi.

(*3*) Total volume of produced water with pressure greater than 250 psi.

(C) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(D) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(E) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(F) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(G) The number of fixed roof atmospheric pressure storage tanks in the facility.

(H) The number of floating roof atmospheric pressure storage tanks in the facility.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (H) of this section for each well-pad (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) with atmospheric pressure storage tanks receiving hydrocarbon liquids whose emissions were calculated using § 98.233(j)(3)(i).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open or not properly seated thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) The total number of separators, wells, or non-separator equipment with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day for which you used Calculation Method 3 (''Count'' from Equation W–15A of this subpart).

(F) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated using Equation W–15A of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(G) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using Equation W–15A of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(H) The total volume of gas vented through open or not properly seated thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or flares.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (F) of this section for each well-pad (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for onshore natural gas processing) with atmospheric pressure storage tanks receiving produced water whose emissions were calculated using § 98.233(j)(3)(ii).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open or not properly seated thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using Equation W–15B of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(F) The total volume of gas vented through open or not properly seated thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or flares.

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (v) of this section for each well-pad (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) by liquid type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(iii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the ''T_{dv}'' values used in Equation W–16 of this subpart).

(iv) For atmospheric pressure storage tanks receiving hydrocarbon liquids, annual CO_2 emissions, in metric tons CO_2, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W–16 of this subpart.

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W–16 of this subpart.

(k) *Condensate storage tanks.* You must indicate whether your facility contains any condensate storage tanks. If your facility contains at least one condensate storage tank, then you must report the information specified in paragraphs (k)(1) and (2) of this section for each condensate storage tank vent stack.

(1) For each condensate storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the condensate storage tank vent stack.

(ii) Indicate if a flare is attached to the condensate storage tank vent stack.

(iii) Indicate whether scrubber dump valve leakage occurred for the condensate storage tank vent according to § 98.233(k)(1).

(iv) Which method specified in § 98.233(k)(1) was used to determine if dump valve leakage occurred.

(2) If scrubber dump valve leakage occurred for a condensate storage tank vent stack, as reported in paragraph

(k)(1)(iii) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each condensate storage vent stack where scrubber dump valve leakage occurred.

(i) Which method specified in § 98.233(k)(2) was used to measure the leak rate.

* * * * *

(l) * * *

(1) For oil wells not routed to a flare, you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only oil wells that are tested in the same basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average flow rate for the tested well.

* * * * *

(2) For oil wells routed to a flare, you must report the information specified in paragraphs (l)(2)(i) through (v) of this section for each well tested. All reported data elements should be specific to the well for which Equation W–17A of § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that are tested in the same basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average flow rate for the tested well.

(3) For gas wells not routed to a flare, you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well(s) in the calendar year.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that are tested in the same basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average annual production rate for the tested well.

* * * * *

(4) For gas wells routed to a flare, you must report the information specified in paragraphs (l)(4)(i) through (iv) of this section for each well tested. All reported data elements should be specific to the well for which Equation W–17B of § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that are tested in the same basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average annual production rate for the tested well.

(m) *Associated natural gas.* You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented during the calendar year, then you must report the information specified in paragraphs (m)(1) through (7) of this section for each well for which associated gas was vented. If associated gas was flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (3) of this section for each well for which associated gas was flared.

(1) Well ID number.

* * * * *

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil. Do not report the GOR if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use Equation W–18 for the well with associated gas venting or flaring emissions).

(5) Volume of oil produced by the well, in barrels, in the calendar year only during the time periods in which associated gas was vented or flared (''V_p'' used in Equation W–18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells from which associated gas was vented or flared in the same sub-basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced by the well during the time periods in which associated gas venting and flaring was occurring. Do not report the volume of oil produced if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use Equation W–18 for the well with associated gas venting or flaring emissions).

(6) Total volume of associated gas sent to sales or used on site and not sent to a vent or flare, in standard cubic feet, in the calendar year only during time periods in which associated gas was vented or flared (''SG'' value used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells from which associated gas was vented or flared in the same basin are wildcat wells and/or delineation wells. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured total volume of associated gas sent to sales for the well during the time periods in which associated gas venting and flaring was occurring. Do not report the volume of gas sent to sales if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use Equation W–18).

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (viii) of this section for each well.

(i) [Reserved]

(ii) Indicate whether the associated gas volume vented from the well was measured using a continuous flow monitor.

(iii) Indicate whether associated gas streams vented from the well were measured with continuous gas composition analyzers.

(iv) Total volume of associated gas vented from the well, in standard cubic feet.

(v) Flow-weighted average mole fraction of CH_4 in associated gas vented from the well.

(vi) Flow-weighted average mole fraction of CO_2 in associated gas vented from the well.

(vii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(viii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(n) *Flare stacks.* You must indicate if your facility has any flare stacks. You must report the information specified in paragraphs (n)(1) through (20) of this section for each flare stack at your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(2) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(3) Unique IDs for each stream routed to the flare if you measure the flow of each stream that is routed to the flare as specified in § 98.233(n)(1)(ii) and/or you measure the gas composition for each stream routed to the flare as specified in § 98.233(n)(3)(iii) or (iv).

(4) Indicate the type of flare (*i.e.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).

(5) Indicate the type of flare assist (*i.e.,* unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).

(6) Indicate whether the pilot flame or combustion flame was monitored continuously, visually inspected, or both. If visually inspected, report the number of inspections during the year, and indicate whether the flare has a continuous pilot or auto igniter. If the pilot flame was monitored continuously, report the number of times the continuous monitoring device was out of service or otherwise inoperable for a period of more than one week.

(7) Indicate whether the volume of gas was determined using a continuous flow measurement device or whether it was determined using parameter monitoring and engineering calculations (§ 98.233(n)(1)(i) for inlet gas to the flare or § 98.233(n)(1)(ii) for each stream routed to the flare). If you switched from one method to the other during the year, then indicate both methods were used.

(8) Indicate whether the gas composition was calculated using a continuous gas composition analyzer or by taking samples of the applicable gas stream(s) at least once per quarter (§ 98.233(n)(3)(i) or (iii) for the inlet gas to the flare or § 98.233(n)(3)(ii) or (iv) for the streams from each source that routes emissions to the flare). If you switched from one method to the other during the year, then indicate both methods were used.

(9) Flare-specific HHV, if you determined a flare-specific HHV based on measured composition of the inlet gas to the flare as specified in § 98.233(n)(8)(i) or if you calculated a flare-specific HHV based on the calculated flow-weighted average composition for the inlet gas to the flare as specified in § 98.233(n)(8)(iii). Each individual stream HHV, if you determined HHVs for each individual stream routed to the flare and you used these HHVs to calculate N_2O emissions for each stream as specified in § 98.233(n)(8)(ii).

(10) For the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and onshore natural gas processing industry segments, estimated fraction of total volume flared that was received from another facility solely for flaring (*e.g.,* gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).

(11) Volume of gas sent to the flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart). If you determine the volume of gas for each stream routed to the flare as specified in § 98.233(n)(1)(ii), then also report the annual volume of each measured stream.

(12) Fraction of the feed gas sent to an un-lit flare based on total time when continuous monitoring of the pilot or periodic inspections indicated the flare was not lit and the flow determined by continuous measurement of flow conducted during the times when the flare was not lit (''Z_u'' in Equation W–19 of this subpart).

(13) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare (§ 98.233(n)(4)). If you used multiple monitoring methods during the year, report the flow-weighted average combustion efficiency based on each tier that applied. Report the efficiency to one decimal place.

(i) If you report using the 95 percent default combustion efficiency, indicate if you are subject to part 60, subpart OOOOb of this chapter or if you are electing to comply with the flare monitoring requirements in part 60, subpart OOOOb of this chapter.

(ii) If you are not required to comply with part 60, subpart OOOOb of this chapter but you elect to comply with the monitoring requirements in § 60.5417b(d)(1)(viii) of this chapter as specified in § 98.233(n)(4), indicate whether you use a calorimeter to continuously determine net heating value (NHV) or if you have demonstrated according to the methods described in § 60.5417b(d)(1)(viii)(C) of this chapter that the NHV consistently exceeds the operating limit specified in § 60.18 of this chapter (or that it consistently exceeds 800 Btu/scf for a pressure assist flare).

(14) Annual average mole fraction of CH_4 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(3)(i) or (ii) (''X_{CH4}'' in Equation W–19 of this subpart), or the annual average CH_4 mole fractions for each stream if you measure composition of each stream routed to the flare as specified in § 98.233(n)(3)(iii) or (iv).

(15) Annual average mole fraction of CO_2 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(3)(i) or (ii) (''X_{CO2}'' in Equation W–20 of this subpart), or the annual average CO_2 mole fractions for each stream if you measure composition of each stream routed to the flare as specified in § 98.233(n)(3)(iii) or (iv).

(16) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W–20 of this subpart).

(17) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W–19 of this subpart).

(18) Annual N_2O emissions, in metric tons N_2O (refer to Equation W–40 of this subpart).

(19) Estimated disaggregated CH_4, CO_2, and N_2O emissions attributed to each source type as determined using engineering calculations and best available data as specified in § 98.233(n)(10) (*i.e.,* AGR vents, dehydrator vents, well venting during completions and workovers with

hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, hydrocarbon liquids and produced water storage tanks, well testing venting and flaring, associated gas venting and flaring, other flared sources).

(20) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used, then you are not required to report the CO_2 mole fraction in paragraph (n)(15) of this section.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(o)(10)(iii) are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (xi) of this section, as applicable, for each centrifugal compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the centrifugal compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) If you conducted volumetric emission measurements as specified in § 98.233(o)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Indicate whether the compressor has wet or dry seals.

(ix) If the compressor has wet seals, the number of wet seals.

(x) If the compressor has dry seals, the number of dry seals.

(xi) Power output of the compressor driver (hp).

(2) * * *

(i) * * *

(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(ii) of this section.

(B) Centrifugal compressor source (wet seal, dry seal, isolation valve, or blowdown valve).

* * * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery system.

* * * * *

(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery system, you are not required to report emissions under this paragraph.

* * * * *

(E) If the leak or vent is routed to flare, combustion, or vapor recovery system, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(o)(10)(iii) must report the information specified in paragraphs (o)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (o)(5)(i) through (iv) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Report the following activity data.

(A) Total number of centrifugal compressors at the facility.

(B) Number of centrifugal compressors that have wet seals.

(C) Number of centrifugal compressors that have atmospheric wet seal oil degassing vents (*i.e.,* wet seal oil degassing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(iv) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(p)(10)(iii) are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (viii) of this section, as applicable, for each reciprocating compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the reciprocating compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) If you conducted volumetric emission measurements as specified in § 98.233(p)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Power output of the compressor driver (hp).

(2) * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery system.

* * * * *

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery system, you are not required to report emissions under this paragraph.

* * * * *

(E) If the leak or vent is routed to a flare, combustion, or vapor recovery system, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) * * *

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W–28 was used to calculate emissions in Equation W–27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(p)(10)(iii) must report the information specified in paragraphs (p)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (p)(5)(i) through (iv) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Report the following activity data.

(A) Total number of reciprocating compressors at the facility.

(B) Number of reciprocating compressors that have rod packing emissions vented directly to the atmosphere (*i.e.,* rod packing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(iv) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(q) *Equipment leak surveys.* For any components subject to or complying with the requirements of § 98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. You must report the information specified in paragraphs (q)(1) and (2) of this section, as applicable, for each well-pad (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments). Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Except as specified in paragraph (q)(1)(iii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(iii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iv) Except for natural gas distribution facilities, indicate whether any of the leak detection surveys used in calculating emissions per § 98.233(q)(2) were conducted for compliance with any of the standards in paragraphs (q)(1)(iv)(A) through (E) of this section. Report the indication per well-pad, gathering and boosting site, or facility, not per component type, as applicable.

(A) The well site or compressor station fugitive emissions standards in § 60.5397a of this chapter.

(B) The well site, centralized production facility, or compressor station fugitive emissions standards in § 60.5397b of this chapter.

(C) The well site, centralized production facility, or compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(D) The standards for equipment leaks at onshore natural gas processing plants in § 60.5400b of this chapter.

(E) The standards for equipment leaks at onshore natural gas processing plants in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(v) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with § 98.233(q) according to § 98.233(q)(1)(iv) for any equipment components at your well-pad, gathering and boosting site, or facility.

(vi) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(vii) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(viii) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in Table W–1) by service type for which leak detection surveys were conducted and emissions calculated according to § 98.233(q).

(ix) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in Table W–1) in vacuum service as defined in § 98.238.

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7) or (8), (f)(5) through (8), (g)(4), (g)(6) or (7), (h)(5), (h)(7) or (8), (i)(1), or (j)(10) for your facility's industry segment. For each component type and leak detection

method combination that is located at your well-pad, gathering and boosting site, or facility, you must report the information specified in paragraphs (q)(2)(i) through (ix) of this section. If a component type is located at your well-pad, gathering and boosting site, or facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (ix) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(vi) through (ix) of this section. If you used Calculation Method 1 (leaker factor emission calculation methodology) for some complete leak surveys and used Calculation Method 2 (leaker measurement methodology) for some complete leak surveys, you must report the information specified in paragraphs (q)(2)(i) through (ix) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Component type.

(iii) Leak detection method used for the screening survey (*e.g.,* Method 21 as specified in § 98.234(a)(2)(i); Method 21 as specified in § 98.234(a)(2)(ii); and OGI and other leak detection methods as specified in § 98.234(a)(1), (3), or (5)).

(iv) Emission factor or measurement method used (*e.g.,* default emission factor; site-specific emission factor developed according to § 98.233(q)(4); or direct measurement according to § 98.233(q)(3)).

(v) Total number of components surveyed by type and leak detection method in the calendar year.

(vi) Total number of the surveyed component types by leak detection method that were identified as leaking in the calendar year (''x_p'' in Equation W–30 of this subpart for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)).

(vii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from Equation W–30 of this subpart for the component type or average duration of leaks for the specified component type determined according to the provisions in § 98.233(q)(3)(ii)).

(viii) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vii) (for surveyed components only).

(ix) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vii) (for surveyed components only).

* * * * *

(r) *Equipment leaks by population count.* If your facility is subject to the requirements of § 98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable. You must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. For each well-pad and gathering and boosting site at onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities you must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately by equipment type and service type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the equipment type and service type.

(iii) Total number of the emission source type at the well-pad, gathering and boosting site, or facility, as applicable (''$Count_e$'' in Equation W–32A of this subpart).

(iv) Average estimated time that the emission source type was operational in the calendar year, in hours (''T_e'' in Equation W–32A of this subpart).

(v) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the emission source type.

* * * * *

(3) You must indicate whether your facility contains any emission source types in vacuum service as defined in § 98.238. If your facility contains equipment in vacuum service, you must report the information specified in paragraphs (r)(3)(i) through (iii) of this section separately for each emission source type in vacuum service that is located at your well-pad, gathering and boosting site, or facility, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Emission source type.

(iii) Total number of the emission source type at the well-pad, gathering and boosting site, or facility, as applicable.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for your facility.

(1) For facilities that report to BOEM's emissions inventory, the BOEM Facility ID(s) that correspond(s) to this facility.

(2) If you adjusted emissions according to § 98.233(s)(1)(i) or (s)(2)(i), report the information specified in paragraphs (s)(2)(i) and (ii) of this section.

(i) Facility operating hours for the year of the most recent BOEM emissions inventory.

(ii) Facility operating hours for the current year.

(3) For each emission source type listed in the most recently published BOEM emissions inventory, report the information specified in paragraphs (s)(3)(i) through (iii) of this section.

(i) Annual CO_2 emissions, in metric tons CO_2.

(ii) Annual CH_4 emissions, in metric tons CH_4.

(iii) Annual N_2O emissions, in metric tons N_2O.

* * * * *

(x) * * *

(1) Well-pad ID.

* * * * *

(y) *Other large release events.* You must indicate whether there were any other large release events from your facility during the reporting year and indicate whether your facility was notified of a potential super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) Unique release event identification number (*e.g.,* Event 1, Event 2).

(3) The latitude and longitude of the release in decimal degrees to at least four digits to the right of the decimal point.

(4) The approximate start date, start time, and duration (in hours) of the release event, and an indication of how the start date and time were determined (determined based on pressure monitor, temperature monitor, other monitored process parameter (specify), assigned based on last monitoring or measurement survey showing no large release, or used the 182-day default maximum duration).

(5) A general description of the event. Include:

(i) Identification of the equipment involved in the release.

(ii) A description of how the release occurred, from one of the following categories: maintenance event, fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

(iii) An indication of whether the release exceeded a threshold in § 98.233(y)(1)(i) or in § 98.233(y)(1)(ii).

(iv) A description of the technology or method used to identify the release.

(v) An indication of whether the release was identified under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or a third-party notification and, if the release was identified under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or a third-party notification, a unique notification ID number for the notification as assigned in paragraph (y)(11)(i) of this section.

(vi) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted and the assumed combustion efficiency for the combusted natural gas.

(6) The total volume of gas released during the event in standard cubic feet.

(7) The volume fraction of CO_2 in the gas released during the event.

(8) The volume fraction of CH_4 in the gas released during the event.

(9) Annual CO_2 emissions, in metric tons CO_2, from the release event that occurred during the reporting year.

(10) Annual CH_4 emissions, in metric tons CH_4, from the release event that occurred during the reporting year and the maximum CH_4 emissions rate, in kilograms per hour, determined for any period of the event according to the provisions of § 98.233(y)(2)(i).

(11) Report the total number of super-emitter release notifications received from a third party for this facility during the reporting year and, for each such super-emitter release notification, report the information specified in paragraphs (y)(11)(i) through (vi) of this section.

(i) Unique notification identification number (*e.g.,* Notification_01, Notification_02). If a unique notification number was provided with a notification received under the provisions of § 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, report the number associated with the event provided in the notification.

(ii) The latitude and longitude of the release as provided in the notification.

(iii) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only) to which the notification was attributed.

(iv) An indication of whether the super-emitter release notification was received under the provisions of § 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, or from another third-party. If the notification was received from another third-party, report the following information about the notifier and data received, if known.

(A) The name of the person and/or company that provided the notification.

(B) The method used during by the notifier to quantify the emissions (satellite detection; remote-sensing equipment on aircraft; mobile monitoring platform; other, specify; or unknown).

(C) The date(s) and time(s) the measurement was made.

(D) The measured methane emission rate and uncertainty bounds (in kilograms per hour).

(v) Based on any assessment or investigation triggered by the notification, indicate if the emissions were from normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device, or undetermined cause.

(vi) An indication of whether the emissions identified via the notification are included in annual emissions reported for under this subpart and, if so, the source type under which those emissions are reported. If the emissions were reported following the requirements of § 98.233(y) as an other large release event, report the unique release event identification number assigned to the other large release event as reported in paragraph (y)(2) of this section. If the emissions identified via the notification are not included in annual emissions reported under this subpart, you must provide the reason for not including the emissions related to this notification (the emissions could not be verified or corroborated during site inspection or facility data records; the location of the emissions as provided in the notification do not belong to the facility; the information was determined not to be credible, explain; other, specify).

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xx), (a)(8)(vi), or (a)(9)(xiii) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xx), (a)(8)(vi), or (a)(9)(xiii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable. You must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated

heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) through (iii) of this section for each unit type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit.

(iii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. For each type of combustion unit at your facility, you must report the information specified in paragraphs (z)(2)(i) through (iv) and (z)(2)(viii) through (x) of this section, except for internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower) or internal fuel combustion units of any heat capacity that are compressor-drivers that combust natural gas meeting the criteria in § 98.233(z)(1) or (2), which must report the information specified in paragraphs (z)(2)(i) through (x) of this section. Information must be reported for each combustion unit type, fuel type, and method for determining the CH_4 emission factor combination, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit including external fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers.

(iii) The type of fuel combusted.

(iv) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(v) The equipment type, including reciprocating 2-stroke-lean burn, reciprocating 4-stroke lean-burn, reciprocating 4-stroke rich-burn, and gas turbine.

(vi) The method used to determine the methane emission factor, including the default emission factor from Table W–7 of subpart W, OEM data, or performance tests in § 98.234(i).

(vii) The value of the CH_4 emission factor (kg CH_4/mmBtu).

(viii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) through (3).

(ix) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) through (3).

(x) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) through (3).

(aa) *Industry segment-specific information.* Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using a flow meter that meets the requirements of § 98.234(b) for quantities that are sent to sale or through the facility and determined by using best available data for other quantities. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (iv) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (D) of this section for the basin as a whole, unless otherwise specified.

* * * * *

(B) The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(C) The quantity of crude oil produced from producing wells that is sent to sale in the calendar year, in barrels.

(D) The quantity of condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

(ii) * * *

(D) The number of producing wells at the end of the calendar year (exclude only those wells permanently shut-in and plugged).

(E) The number of producing wells acquired during the calendar year.

(F) The number of producing wells divested during the calendar year.

(G) The number of wells completed during the calendar year.

(H) The number of wells permanently shut-in and plugged during the calendar year.

* * * * *

(iii) Report the information specified in paragraphs (aa)(1)(iii)(A) through (E) of this section for each well located in the facility.

(A) Well ID number.

(B) Well-pad ID.

(C) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(D) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil produced that is sent to sale in the calendar year, in barrels.

(E) For each well permanently shut-in and plugged during the calendar year, the quantity of condensate produced that is sent to sale in the calendar year, in barrels.

(iv) Report the information specified in paragraphs (aa)(1)(iv)(A) through (F) of this section for each well-pad located in the facility.

(A) A unique name or ID number for the well-pad.

(B) Sub-basin ID.

(C) The latitude and longitude of the well-pad representing the geographic centroid or center point of the well-pad in decimal degrees to at least four digits to the right of the decimal point.

(D) For each well-pad with a well that was permanently shut-in and plugged during the calendar year, report the quantity of gas produced from all producing wells on the well-pad that is sent to sale in the calendar year, in thousand standard cubic feet.

(E) For each well-pad with a well that was permanently shut-in and plugged during the calendar year, report the quantity of crude oil produced from all producing wells on the well-pad that is sent to sale in the calendar year for sales, in barrels.

(F) For each well-pad with a well that was permanently shut-in and plugged during the calendar year, report the quantity of condensate produced from all producing wells on the well-pad that is sent to sale in the calendar year, in barrels.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) through (vi) of this section.

(i) The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(ii) The quantity of crude oil produced from producing wells that is sent to sale in the calendar year, in barrels.

(iii) The quantity of condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

(iv) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(v) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil produced that is sent to sale in the calendar year, in barrels.

(vi) For each well permanently shut-in and plugged during the calendar year, the quantity of condensate produced that is sent to sale in the calendar year, in barrels.

(3) For natural gas processing, if your facility fractionates NGLs and also reports as a supplier to subpart NN of this part, you must report the information specified in paragraphs (aa)(3)(ii) and (aa)(3)(v) through (ix) of this section. Otherwise, report the information specified in paragraphs (aa)(3)(i) through (ix) of this section.

(i) The quantity of natural gas received at the gas processing plant for processing in the calendar year, in thousand standard cubic feet.

* * * * *

(viii) Indicate whether the facility reports as a supplier to subpart NN of this part.

(ix) The quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sales without being processed by the facility.

(4) * * *

(i) The quantity of natural gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

* * * * *

(5) * * *

(ii) The quantity of natural gas withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet.

* * * * *

(6) For LNG import equipment, report the quantity of LNG imported that is sent to sale in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported that is sent to sale in the calendar year, in thousand standard cubic feet.

(8) * * *

(ii) The quantity of LNG withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (v) of this section.

* * * * *

(ii) The quantity of natural gas transported through the facility to a downstream endpoint such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

* * * * *

(iv) The quantity of all hydrocarbon liquids transported to a downstream endpoint such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting facility in the calendar year, in barrels.

(v) Report the information specified in paragraphs (aa)(10)(v)(A) through (E) of this section for each gathering and boosting site located in the facility.

(A) A unique name or ID number for the gathering and boosting site.

(B) Gathering and boosting site type (gathering compressor station, centralized oil production site, gathering pipeline, or other fence-line site).

(C) State.

(D) For gathering compressor stations, centralized oil production sites, and other fence-line sites, county.

(E) For gathering compressor stations, centralized oil production sites, and other fence-line sites, the latitude and longitude of the gathering and boosting site representing the geographic centroid or center point of the site in decimal degrees to at least four digits to the right of the decimal point.

(11) * * *

(ii) The quantity of natural gas withdrawn from underground natural gas storage and LNG storage (regasification) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to underground natural gas storage and LNG storage (liquefied) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transported through the facility and transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

* * * * *

(bb) *Missing data.* For any missing data procedures used, report the information in § 98.3(c)(8) and the procedures used to substitute an unavailable value of a parameter, except as provided in paragraphs (bb)(1) and (2) of this section.

* * * * *

(cc) *Delay in reporting for wildcat wells and delineation wells.* If you elect to delay reporting the information in paragraph (g)(5)(i) or (ii), (g)(5)(iii)(A) or (B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(v), (l)(2)(v), (l)(3)(iv), (l)(4)(iv), or (m)(5) or (6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

(dd) *Drilling mud degassing.* You must indicate whether there were mud degassing operations at your facility, and if so, which methods (as specified in § 98.233(dd)) were used to calculate emissions. For wells for which your facility performed mud degassing operations and used Calculation Method 1, then you must report the information specified in paragraph (dd)(1) of this section. For wells for which your facility performed mud degassing operations and used Calculation Method 2, then you must report the information specified in paragraph (dd)(2) of this section.

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(1)(i) through (vii) of this section.

(i) Well ID number.

(ii) Approximate total depth below surface, in feet.

(iii) Total time that drilling mud is circulated in the well, in minutes.

(iv) The composition of the drilling mud: water-based, oil-based, or synthetic.

(v) If the well is not a representative well, Well ID number of the representative well used to derive the CH_4 emission rate used to calculate CH_4 emissions for this well.

(vi) If the well is a representative well, report the information specified in paragraphs (dd)(1)(vi)(A) through (D) of this section.

(A) Average mud rate, in gallons per minute.

(B) Concentration of natural gas in the drilling mud (X_n in Equation W–41), in parts per million.

(C) Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in Equation W–41).

(D) Calculated CH_4 emissions rate in standard cubic per minute ($ER_{s,CH4,r}$ in Equation W–42).

(vii) Annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).

(2) For each well for which you used Calculation Method 2 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(2)(i) through (iv) of this section.

(i) Well ID number.

(ii) Total number of drilling days.

(iii) The composition of the drilling mud: water-based, oil-based, or synthetic.

(iv) Annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).

(ee) *Crankcase vents.* You must indicate whether your facility performs any crankcase venting from reciprocating internal combustion engines or gas turbines. If your facility contains at least one crankcase vent on an applicable engine, you must report the information specified in paragraphs (ee)(1) through (4) of this section for each well-pad (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) Total number of crankcase vents at the well-pad, gathering and boosting site, or facility, as applicable (''Count'' in Equation W–45 of this subpart).

(3) Average estimated time that the reciprocating internal combustion engines or gas turbines with crankcase venting were operational in the calendar year, in hours (''T'' in Equation W–45 of this subpart).

(4) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(ee)(1).

■ 16. Amend § 98.238 by:

■ a. Removing the definition for ''Acid gas removal vent emissions'' and adding the definition for ''Acid gas removal unit (AGR) vent emissions'' in alphabetical order;

■ b. Adding definitions for ''Atmospheric pressure storage tank,'' ''Automated liquids unloading,'' and ''Centralized oil production site'' in alphabetical order;

■ c. Revising the definitions for ''Compressor mode'' and ''Compressor source'';

■ d. Adding definitions for ''Crankcase venting,'' ''Drilling mud,'' and ''Drilling mud degassing'' in alphabetical order;

■ e. Removing the second definition for ''Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements'';

■ f. Revising the definitions for ''Flare stack emissions'' and ''Forced extraction of natural gas liquids'';

■ g. Adding the definition for ''Gathering and boosting site'' in alphabetical order;

■ h. Revising the definitions for ''Gathering and boosting system'' and ''Gathering and boosting system owner or operator''; and

■ i. Adding definitions for ''Gathering compressor station,'' ''Gathering pipeline site,'' ''In vacuum service,'' ''Manual liquids unloading,'' ''Mud rate,'' ''Nitrogen removal unit (NRU),'' ''Nitrogen removal unit vent emissions,'' ''Other large release event,'' ''Produced water,'' ''Routed to combustion,'' ''Well blowout,'' and ''Well release'' in alphabetical order.

The additions and revisions read as follows:

§ 98.238 Definitions.

* * * * *

Acid gas removal unit (AGR) vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.,* an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

* * * * *

Atmospheric pressure storage tank means a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.

Automated liquids unloading means an unloading that is performed without manual interference. Examples of automated liquids unloadings include a timing and/or pressure device used to optimize intermittent shut-in of the well before liquids choke off gas flow or to open and close valves, continually operating equipment that does not require presence of an operator such as rod pumping units, automated and unmanned plunger lifts, or other unloading activities that do not entail a physical presence at the well-pad.

* * * * *

Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A *centralized oil production site* is a type of gathering and boosting site for purposes of reporting under § 98.236.

* * * * *

Compressor mode means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, ''mode'' refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, wet seal oil degassing vents, and dry seal vents. For reciprocating compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

* * * * *

Crankcase venting means the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process.

* * * * *

Drilling mud means a mixture of clays and additives with water, oil, or synthetic materials. While drilling, the drilling mud is continuously pumped through the drill string and out the bit to cool and lubricate the drill bit, and move cuttings through the wellbore to the surface.

Drilling mud degassing means the practice of safely removing pockets of free gas entrained in the drilling mud once it is outside of the wellbore.

* * * * *

Flare stack emissions means CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 emissions resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid.

Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within the onshore petroleum and natural gas gathering and boosting industry segment.

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production or one or more other gathering and boosting systems and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells or one or more other gathering and boosting systems to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

Gathering compressor station means any permanent combination of one or more compressors located on one or more contiguous or adjacent properties that are part of the onshore petroleum and natural gas gathering and boosting facility that move natural gas at increased pressure through gathering pipelines or into or out of storage. A *gathering compressor station* is a type of gathering and boosting site for purposes of reporting under § 98.236.

Gathering pipeline site means all of the gathering pipelines within a single state. A *gathering pipeline site* is a type of gathering and boosting site for purposes of reporting under § 98.236.

* * * * *

In vacuum service means equipment operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

* * * * *

Manual liquids unloading means an unloading when field personnel attend to the well at the well-pad, for example to manually plunge a well at the site using a rig or other method, to open a valve to direct flow to an atmospheric tank to clear the well, or to manually shut-in the well to allow pressure to build in the well-bore. Manual unloadings may be performed on a routine schedule or on ''as needed'' basis.

* * * * *

Mud rate means the pumping rate of the mud by the mud pumps, usually measured in gallons per minute (gpm).

* * * * *

Nitrogen removal unit (NRU) means a process unit that separates nitrogen from natural gas using various separation processes (*e.g.,* cryogenic units, membrane units, etc.)

Nitrogen removal unit vent emissions means the nitrogen gas separated from the natural gas and released with methane and other gases to the atmosphere, flare, or other combustion unit.

* * * * *

Other large release event means any planned or unplanned uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 other than under § 98.233(y) to appropriately estimate these emissions. *Other large release events* include, but are not limited to, well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. *Other large release events* also include failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233(a) through (s), (w), (x), (dd), or (ee) by the threshold in § 98.233(y)(1)(ii).

* * * * *

Produced water means the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

* * * * *

Routed to combustion means, for onshore petroleum and natural gas production facilities, natural gas distribution facilities, and onshore petroleum and natural gas gathering and boosting facilities, that emissions are routed to stationary or portable fuel combustion equipment specified in § 98.232(c)(22), (i)(7), or (j)(12), as applicable. For all other industry segments in this subpart, *routed to combustion* means that emissions are routed to a stationary fuel combustion unit subject to subpart C of this part (General Stationary Fuel Combustion Sources).

* * * * *

Well blowout means a complete loss of well control for a long duration of time resulting in an emissions release.

* * * * *

Well release means a short duration of uncontrolled emissions release from a well followed by a period of controlled emissions release in which control techniques were successfully implemented.

* * * * *

17. Remove table W–1A, table W–1B, table W–1C, table W–1D, and table W–1E to subpart W of part 98 and add table W–1 to subpart W of part 98 in numerical order to read as follows:

TABLE W–1 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf whole gas/hour/unit)
Population Emission Factors—Pneumatic Device Vents and Pneumatic Pumps, Gas Service [1]		
• Onshore petroleum and natural gas production	Continuous Low Bleed Pneumatic Device Vents [2]	6.8
• Onshore petroleum and natural gas gathering and boosting	Continuous High Bleed Pneumatic Device Vents [2]	21
	Pneumatic Pumps [3]	13.3
• Onshore natural gas processing	Continuous Low Bleed Pneumatic Device Vents [2]	6.8
• Onshore natural gas transmission compression	Continuous High Bleed Pneumatic Device Vents [2]	30
• Underground natural gas storage		
• Natural gas distribution		
Population Emission Factors—Major Equipment, Gas Service [1]		
• Onshore petroleum and natural gas production	Wellhead	8.87
	Separator	9.65
• Onshore petroleum and natural gas gathering and boosting.	Meters/Piping	7.04
	Compressor	13.8
	Dehydrator	8.09
	Heater	5.22
	Storage Vessel	1.83
Population Emission Factors—Major Equipment, Crude Service		
Onshore petroleum and natural gas production	Wellhead	4.13
	Separator	4.77
	Meters/Piping	12.4
	Compressor	13.8
	Dehydrator	8.09
	Heater	3.2
	Storage Vessel	1.91
Population Emission Factors—Gathering Pipelines, by Material Type [4]		
Onshore petroleum and natural gas gathering and boosting	Protected Steel	0.93
	Unprotected Steel	8.2
	Plastic/Composite	0.28
	Cast Iron	8.4

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] Emission factor is in units of "scf whole gas/hour/device."
[3] Emission factor is in units of "scf whole gas/hour/pump."
[4] Emission factors are in units of "scf whole gas/hour/mile of pipeline."

■ 18. Revise table W–2 to subpart W of part 98 to read as follows:

TABLE W–2 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf whole gas/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting—All Components, Gas Service [1]			
Valve	9.6	5.5	16
Flange	6.9	4.0	11
Connector (other)	4.9	2.8	7.9
Open-Ended Line [2]	6.3	3.6	10
Pressure Relief Valve	7.8	4.5	13
Pump Seal	14	8.3	23
Other [3]	9.1	5.3	15
Leaker Emission Factors—Onshore Petroleum and Natural Gas Production—All Components, Oil Service			
Valve	5.6	3.3	9.2
Flange	2.7	1.6	4.4
Connector (other)	5.6	3.2	9.1

TABLE W–2 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS—Continued

Equipment components	Emission factor (scf whole gas/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Open-Ended Line	1.6	0.93	2.6
Pump [4]	3.7	2.2	6.0
Other [3]	2.2	1.0	2.9

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.
[3] ''Others'' category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).
[4] The pumps component type in oil service includes agitator seals.

■ 19. Remove table W–3A and table W–3B to subpart W of part 98 and add table W–3 to subpart W of part 98 in numerical order to read as follows:

TABLE W–3 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf total hydrocarbon/ hour/component)
Population Emission Factors—Storage Wellheads, Gas Service		
Underground natural gas storage	Connector	0.01
	Valve	0.1
	Pressure Relief Valve	0.17
	Open-Ended Line	0.03

■ 20. Remove table W–4A and table W–4B to subpart W of part 98 and add table W–4 to subpart W of part 98 in numerical order to read as follows:

TABLE W–4 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf total hydrocarbon/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Compressor Components, Gas Service			
Valve [1]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter	19.33	12.39	31.6
Other [2]	4.1	2.63	6.70
Leaker Emission Factors—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Non-Compressor Components, Gas Service			
Valve [1]	6.42	4.12	10.5
Connector	5.71	3.66	9.3
Open-Ended Line	11.27	7.22	18.4
Pressure Relief Valve	2.01	1.29	3.28
Meter	2.93	1.88	4.79
Other [2]	4.1	2.63	6.70
Leaker Emission Factors—Underground Natural Gas Storage—Storage Station, Gas Service			
Valve [1]	14.84	9.51	24.2
Connector (other)	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6
Other [2]	4.1	2.63	6.70

TABLE W–4 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS—Continued

Equipment components	Emission factor (scf total hydrocarbon/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Underground Natural Gas Storage—Storage Wellheads, Gas Service			
Valve[1]	4.5	3.2	7.35
Connector (other than flanges)	1.2	0.7	1.96
Flange	3.8	2.0	6.21
Open-Ended Line	2.5	1.7	4.08
Pressure Relief Valve	4.1	2.5	6.70
Other[2]	4.1	2.5	6.70

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8) for onshore natural gas transmission compression, and as specified in § 98.232(f)(6) and (8) for underground natural gas storage.

■ 21. Remove table W–5A and table W–5B to subpart W of part 98 and add table W–5 to subpart W of part 98 in numerical order to read as follows:

TABLE W–5 TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf methane/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service		
LNG storage LNG import and export equipment	Vapor Recovery Compressor[1]	4.17
Population Emission Factors—Below Grade Transmission-Distribution Transfer Station Components and Below Grade Metering-Regulating Station[2] Components, Gas Service[3]		
Natural gas distribution	Below Grade T–D Transfer Station	0.30
	Below Grade M&R Station	0.30
Population Emission Factors—Distribution Mains, Gas Service[4]		
Natural gas distribution	Unprotected Steel	5.1
	Protected Steel	0.57
	Plastic	0.17
	Cast Iron	6.9
Population Emission Factors—Distribution Services, Gas Service[5]		
Natural gas distribution	Unprotected Steel	0.086
	Protected Steel	0.0077
	Plastic	0.0016
	Copper	0.03
Population Emission Factors—Interconnect, Direct Sale, or Farm Tap Station Stations[2 3]		
Onshore natural gas transmission pipeline	Transmission Company Interconnect M&R Station	166
	Direct Sale or Farm Tap Station	1.3
Population Emission Factors—Transmission Pipelines, Gas Service[4]		
Onshore natural gas transmission pipeline	Unprotected Steel	0.74
	Protected Steel	0.041
	Plastic	0.061
	Cast Iron	27

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

[2] Excluding customer meters.

[3] Emission Factor is in units of "scf methane/hour/station."

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

[5] Emission Factor is in units of "scf methane/hour/number of services."

■ 22. Remove table W–6A and table W–6B to subpart W of part 98 and add table W–6 to subpart W of part 98 in numerical order to read as follows:

TABLE W–6 TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf methane/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Storage and LNG Import and Export Equipment—Storage Components and Terminals Components, LNG Service			
Valve	1.19	0.23	1.94
Pump Seal	4.00	0.73	6.54
Connector	0.34	0.11	0.56
Other [1]	1.77	0.99	2.9
Leaker Emission Factors—LNG Storage and LNG Import and Export Equipment—Storage Components and Terminals Components, Gas Service			
Valve [2]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6
Other [3]	4.1	2.63	6.70
Leaker Emission Factors—Natural Gas Distribution—Transmission-Distribution Transfer Station [4] Components, Gas Service			
Connector	1.69		2.76
Block Valve	0.557		0.91
Control Valve	9.34		15.3
Pressure Relief Valve	0.27		0.44
Orifice Meter	0.212		0.35
Regulator	0.772		1.26
Open-ended Line	26.131		42.7

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7) and § 98.232(h)(7) and (8).
[4] Excluding customer meters.

■ 23. Revise table W–7 to subpart W of part 98 to read as follows:

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR INTERNAL COMBUSTION EQUIPMENT

Internal combustion equipment type	Emission factor (kg CH_4/mmBtu)
Reciprocating Engine, 2-stroke lean-burn	0.658
Reciprocating Engine, 4-stroke lean-burn	0.522
Reciprocating Engine, 4-stroke rich-burn	0.045
Gas Turbine	0.004

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