ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2011–0512; FRL–9456–4]

RIN 2060–AR09

Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Electronics Manufacturing and the Petroleum and Natural Gas Systems Categories of the Greenhouse Gas Reporting Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes technical revisions to the electronics manufacturing and the petroleum and natural gas systems source categories of the greenhouse gas reporting rule. Proposed changes include providing clarification on existing requirements, increasing flexibility for certain calculation methods, amending data reporting requirements clarifying terms and definitions, and technical corrections. In addition, the Environmental Protection Agency is proposing to amend the definition of heat transfer fluids in subpart I to include more fluorocarbons used as heat transfer fluids in the electronics manufacturing industry.

DATES: *Comments.* Comments must be received on or before October 11, 2011, unless a public hearing is held, in which case comments must be received on or before October 24, 2011.

Public Hearing. A public hearing will be held if requested. To request a hearing, please contact the person listed in the following **FOR FURTHER INFORMATION CONTACT** section by September 16, 2011. If requested, the hearing will be conducted on September 26, 2011, in the Washington, DC area. EPA will publish further information about the hearing in the **Federal Register** if a hearing is requested.

ADDRESSES: You may submit your comments, identified by Docket ID No. EPA–HQ–OAR–2011–0512 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.

E-mail: GHG_Reporting_Rule_Oil_And_Natural_Gas@epa.gov. Include Docket ID No. *EPA–HQ–OAR–2011–0512* in the subject line of the message.

- *Fax:* (202) 566–9744.
- *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code 28221T, Attention Docket ID No. EPA–HQ–OAR–2011–0512, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, Attention Docket ID No. EPA–HQ–OAR–2011–0512, 1301 Constitution Avenue, NW., Washington, DC 20004. Such deliveries are only accepted during the docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. *EPA–HQ–OAR–2011–0512*, Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

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

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone number:* (202) 343–9263; *fax number:* (202) 343–2342; *e-mail address: GHGReportingRule@epa.gov.* For technical questions, please see the Greenhouse Gas Reporting Program Web site *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.* To submit a question, select *Rule Help Center*, followed by *Contact Us.* To obtain information about the public hearing or to register to speak at the public hearing, please go to *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.* Alternatively, you may contact Carole Cook at 202–343–9263.

SUPPLEMENTARY INFORMATION:

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of today's proposal will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on EPA's greenhouse gas reporting rule Web site at *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.*

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

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). If finalized, these amended regulations could affect owners or operators of petroleum and natural gas systems and certain electronic manufacturers. Regulated categories and entities may include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Source category	NAICS	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211	Extractors of crude petroleum and natural gas.
	211112	Natural gas liquid extraction facilities.
Electronics Manufacturing	334111	Microcomputers manufacturing facilities.
	334413	Semiconductor, photovoltaic (solid-state) device manufacturing facilities.
	334419	Liquid Crystal Display (LCD) unit screens manufacturing facilities.
	334419	Micro-electro-mechanical systems (MEMS) manufacturing facilities.

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

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

AGA American Gas Association
API American Petroleum Institute
AXPC American Exploration and Production Council
BAMM Best Available Monitoring Methods
BOEMRE Bureau of Ocean Energy Management, Regulation and Enforcement
CAA Clean Air Act
CBI confidential business information
CEC Chesapeake Energy Corporation
CEMS continuous emission monitoring systems
cfd cubic feet per day
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e CO_2-equivalent
COR certificate of representation
e-GGRT electronic greenhouse gas reporting tool
EIA Economic Impact Analysis
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FCML Field Code Master List
FERC Federal Energy Regulatory Commission
FR **Federal Register**
GHG greenhouse gas
GPA Gas Processors Association
GOR gas to oil ratio
GRI Gas Research Institute
Hp horsepower
GWP global warming potential
HHV high heat value
HTF heat transfer fluid
IBR incorporation by reference
ICR information collection request
LDC Local Distribution Company
ISO International Organization for Standardization
kg kilograms
LDCs local natural gas distribution companies
LNG liquefied natural gas
M&R meters and regulators
mmBtu million British thermal units
mmHg millimeters of Mercury
MMscfd million standard cubic feet per day
$mTCO_2e$ million metric tons carbon dioxide equivalent
MRR mandatory GHG reporting rule
N_2O nitrous oxide
NAICS North American Industry Classification System
NF_3 nitrogen trifluoride
NGLs natural gas liquids
NPS nominal pipe size
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality, Planning and Standards
OMB Office of Management and Budget
PHMSA Pipeline and Hazardous Material Safety Administration
QA/QC quality assurance/quality control
RFA Regulatory Flexibility Act
SBA Small Business Administration
SBREFA Small Business Regulatory Enforcement and Fairness Act
SF_6 sulfur hexafluoride
T–D Transmission Distribution
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
USC United States Code

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I. Background

A. How is this preamble organized?

The first section of this preamble contains the basic background information about the origin of these proposed rule amendments and request for public comment. This section also discusses EPA's use of legal authority under the CAA to collect data on GHGs.

The second section of this preamble describes in detail the changes that are being proposed to correct technical errors or to address implementation issues identified by EPA and others. This section also presents EPA's rationale for the proposed changes and identifies issues on which EPA is particularly interested in receiving public comments.

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

B. Background on the Proposed Action

EPA published subpart I: Electronics Manufacturing of the Greenhouse Gas Reporting Program (GHGRP) on December 1, 2010 (75 FR 74774) subpart I of the GHGRP requires monitoring and reporting of GHG emissions from electronics manufacturing. Electronics manufacturing facilities covered by subpart I are those that have emissions equal to or greater than 25,000 $mtCO_2e$.

Following the publication of subpart I in the **Federal Register**, 3M Company

(3M) sought reconsideration of the final rule requirements for reporting fluorinated heat transfer fluids (HTFs). In this action EPA, is proposing amendments to the provisions in subpart I related to calculating and reporting fluorinated HTFs to reflect the Agency's intent to cover all fluorocarbons (except for ozone depleting substances regulated under EPA's Stratospheric Protection Regulations at 40 CFR part 82) that can enter the atmosphere under the conditions in which HTFs are used in the electronics manufacturing industry.

EPA published Subpart W: Petroleum and Natural Gas Systems of the Greenhouse Gas Reporting Rule on November 30, 2010(75 FR 74458). Subpart W of the GHGRP, which applies to facilities in specific segments of the petroleum and natural gas industry that emit GHGs greater than or equal to 25,000 mtCO_2e per year, covers approximately 85 percent of GHG emissions—including vented, equipment leak, and combustion emissions—from facilities in specific segments of the petroleum and natural gas industry.

Following the publication of subpart W in the **Federal Register**, several industry groups requested reconsideration of several provisions in the final rule. Part of the proposed amendments in this action are in response to those requests for reconsideration. Today we are granting reconsideration of, and requesting comment on, those issues raised in the petitions listed in Table 2 where indicated in such Table that the issue is addressed in this action. While we do not necessarily agree that each of those identified issues meet the criteria for reconsideration, we nonetheless believe that they do raise important implementation issues and are thus granting reconsideration of those issues and proposing concomitant revisions to the rule. At this time we are not granting reconsideration of other issues raised in those petitions where indicated in the following table that they are not being addressed in this action but will consider those issues at a later time.

TABLE 2—PETITIONS FOR RECONSIDERATION

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
American Gas Association by letter dated March 2, 2011.	Non custody transfer city gate station terminology. AGA asserted that "[s]everal provisions in the Subpart W rule and preamble seem to imply that a 'non-custody-transfer city gate station' will always have a meter".	Yes.
	Custody transfer city gate station terminology. AGA asserted that the term "custody transfer city gate station" in subpart W was unclear and needed clarification.	Yes.
	Use of GTI emission factors. AGA requested reconsideration of the emissions factors for Local Distribution Companies in the final rule.	Partially.
	New emission factor formulas are confusing or contain math errors that vastly inflate emission estimates. AGA asserted that the "[t]he new emissions factor equations W–30, W–31 and W–32 in the final rule are confusing. Since these formulas were not included in the proposed rule, AGA did not have an opportunity to comment on them".	Yes.
	New electronic reporting form is not yet available for comment or testing. AGA asserted that "[s]takeholders should be given the opportunity to comment and to have access to the reporting software to perform trial runs.	No. This is being addressed in a separate package.
	EPA should exclude small internal combustion sources, not just external combustion. AGA asserted that "EPA should revise the final rule to provide a de minimis exemption for small internal and external combustion sources at underground storage facilities." Also "AGA request reconsideration of this new exclusion for small combustion sources and revision to include both small internal and external combustion sources * * *".	Yes.
	AGA asserted that "[t]he rule contains conflicting provisions regarding whether emissions from dehydrator units at underground storage facilities should or should not be reported".	No.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	AGA asserted that "EPA did not provide rational explanation for using outdated inaccurate emission factors rather than modern updated emission factors".	Yes.
	AGA asserted that "[d]efinition of 'facility' is overbroad and confusing." The facility definition referred to here is found in 40 CFR 98.238.	No.
	AGA asserted that "It was arbitrary and capricious for EPA to create a subpart W reporting regulation for a null set—LNG storage facilities will not exceed the 25,000 ton per year threshold".	No.
	AGA asserted that "It was arbitrary and capricious for EPA to create a subpart W reporting regulation for LNG import and export facilities—which have only minimal methane leaks".	No.
Chesapeake Energy/American Exploration and Production Council by Letter Dated January 31, 2011.	Measurement of Emissions. CEC/AXPC asserted that "EPA proposed to require costly measurement and reporting of emissions from hundreds of thousands of sources. Commenters asked EPA to adopt a reasonable threshold for measurement, so that emissions could still be accounted for, but in a cost-effective way. Commenters recommended using the API Compendium for that purpose".	No.
	De minimis emissions from portable equipment. CEC/AXPC asserted that "[t]he final rule likewise fails to adequately support requiring the reporting of de minimis emissions from portable equipment as EPA proposedEPA asserts a truism that all emissions contribute to sector emissions overall".	Yes.
	Designated Representative. CEC/AXPC requested reconsideration of the designated representative provisions in the final rule.	Yes.
	Dump Valves. CEC/AXPC asserts that "[t]he requirement to measure and report emissions from dump valves associated with onshore production storage tanks * * * is a new and unreasonable ongoing monitoring and record keeping burden * * *".	No.
	Best Available Monitoring Methods.	No. This is being addressed in a separate action (76 FR 37300).
	Emissions Manifolded to Common Vents. CEC/AXPC asserted that the final provisions for centrifugal compressor monitoring "[n]ot only expands the rule to cover equipment that was not identified in the proposed rule, but it is also inconsistent and creates ambiguity for covered sources regarding what is required".	No.
	Compressor Monitoring. CEC/AXPC asserts that "[t]he final rule imposes a new obligation to monitor and report that would require major piping modifications and that would unduly threaten worker safety".	No.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Excluding Boosting Stations. CEC/AXPC asserted that ''[t]he final rule fails to distinguish between a boosting station, which is exempt, and an 'onshore natural gas transmission compression facility' which must report under the rule''.	Yes.
	Onshore Natural Gas Transmission Compression Industry Segment Definition. CEC/AXPC asserted that ''[a]s presently drafted, the unclear and inconsistent final provisions render the rule arbitrary and capricious and contrary to law.'' And ''The term 'onshore natural gas transmission compression' means a stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines or into storage. 40 CFR § 98.230(a)(4). A transmission compressor station can include equipment to separate liquids or dehydrate natural gas *Id.* However, according to the final rule this source category does not include gathering lines and boosting stations''.	Yes.
	Onshore Natural Gas Processing Industry Segment Definition. CEC/AXPC asserted that ''[a]s presently drafted, the unclear and inconsistent final provisions render the rule arbitrary and capricious and contrary to law.'' CEC/AXPC further stated concerns with the definition for onshore natural gas processing industry segment definition and where the segment differs from onshore natural gas transmission industry segment, and from gathering lines and boosting stations.	Yes.
	Gathering Lines and Boosting Stations. CEC/AXPC asserted that ''EPA noted that the 'final rule does not require reporting of emissions from [the] gathering and boosting segment of the industry.' Thisis not helpful and gives industry no clarity regarding which compressor stations are required to report''.	Yes.
	Mapping Wells to Fields. CEC/AXPC asserted that ''EPA has not clarified how reporting entities are supposed to map wells to a particular 'field.' '' Also, CEC/AXPC asserted that ''[w]ithout sufficient clarity regarding what wells are in a particular field, it is difficult for covered sources to know with certainty what gas composition is considered representative for each well''.	Yes.
	Definition of Facility for Onshore Petroleum and Natural Gas Production. CEC/AXPC asserted that the ''EPA has not provided a reasoned explanation for why a term other than 'facility' cannot be adopted for Subpart w (such as 'Reporting Area') in order to avoid unintended confusion and inaccuracies in reporting''.	No.
	Pipeline Quality Natural Gas. CEC/AXPC asserted that ''[t]here is not a clear and unambiguous definition in the final rule for 'pipeline quality' natural gas''.	Yes.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Producing Horizon/formation definition. CEC/AXPC asserted that "[t]here is not a clear and unambiguous definition provided in the final rule for the term 'producing horizon/formation' ".	Yes.
	Well testing venting and flaring clarification. CEC/AXPC asserted that "[t]he final rule is unclear regarding the requirement to report emissions from well testing venting and flaring".	Yes.
	Associated Gas Venting and Flaring. CEC/AXPC asserted that "40 CFR 98.233(m) imposes a requirement to report emissions from associated gas venting and flaring not in conjunction with well testing. While this regulation references 40 CFR 98.233(l), that definition is unclear. Therefore industry is left without clarity regarding what emissions are included in 'associated gas venting and flaring not in conjunction with well testing' ".	No.
	Pneumatic Devices. CEC/AXPC asserted that "EPA has not given sufficient consideration to the burden imposed by requiring that the bleed rate of each device be determined in order to count and classify the devices".	Yes.
	Blowdown Vent Stacks. CEC/AXPC asserted that "[t]he sources that are required to report emissions from blowdown vent stacks are not clear".	Yes.
American Petroleum Institute by Letter Dated January 31, 2011.	Best Available Monitoring Methods	No. This is being addressed in a separate action (76 FR 37300).
	Exclusion for 'small' internal combustion sources is needed. API asserted that "EPA should extend the exclusion for small external combustion sources to small internal combustion sources".	Yes.
	Stuck dump valves to separators/tanks in onshore production operations. API asserted that "[t]he new requirement to report emissions from stuck dump valves requires reporters to check all dump valves on a well site * * * These requirements represent an administrative burden for reports that was not contemplated in the proposed rule".	No.
	Reporting requirements for centrifugal and reciprocating compressor venting at onshore natural gas processing facilities. API requested EPA to reconsider an asserted expansion of reporting requirements for centrifugal and reciprocating compressor venting at onshore natural gas processing facilities.	No.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Requirements for flare stack emission associated with onshore oil and gas production. API asserted that "[e]missions from flare stacks associated with onshore oil and gas production were not included in the Petroleum and Natural Gas production industry segment in the proposed rule * * * the inclusion of emissions from flare stacks associated with onshore oil and gas production is duplicative, burdensome, and a potential source of reporting inaccuracies".	Yes.
	Reporting requirements for all venting and flaring activities in the production source category. API asserts that "EPA's expansion of the reporting obligations in 98.233(m) to include upset or maintenance gas from producing wells imposes additional and extensive burdens on regulated parties which was not included in the proposal".	No.
	Use of gas composition based on available sample analysis for reporters without continuous gas composition analyzer. API asserts that "EPA should resolve the ambiguity created by the current language".	Yes.
	Portable combustion equipment that cannot move on roadways under its own power and drive train that is stationed at a wellhead for less than 30 days in a reporting year. API asserts that "[t]he final rule requires reporters to account for this equipment, despite the fact that it is on site for an extremely short period of time * * * it is unrealistic to expect reporters to measure emissions from every piece of portable combustion equipment that is only onsite for a matter of days".	Yes.
	Separate calculations for subsonic and supersonic flow when both happen during a single completion. API asserted that "[t]he proposed rule did not include a requirement that well completions have separate calculations for subsonic and supersonic flow when both occur during a single completion. The final rule adds this requirement, which is not technically possible".	Yes.
	Flow meter requirements. API asserts that "[t]he final rule adds a requirement at 40 CFR 98.234(b) that all flow meters, composition analyzers and pressure gauges be operated and calibrated according to the procedures in Section 98.3(i) of the MRR * * * API is concerned about the potential unintended consequence following the addition of stationary source combustion equipment at a well pad at new 40 CFR 98.232(C)(22), which required compliance with 40 CFR 98.233(z)(2)(1)".	Yes.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Emission factors for continuous high-bleed, continuous low-bleed, and intermittent bleed pneumatic devices. API asserted that "[a]lthough EPA has provided emission factors in Table W–1A that apply to continuous high-bleed, continuous low-bleed, and intermittent bleed pneumatic devices, EPA has not provided guidance on how to classify pneumatic devices according to these three categories".	Yes.
	Definitions to Industry Categories. API asserted that the "[a]ltered final rule creates ambiguity as to whether certain facilities are included in the production category, excluded as gathering or booster stations, or included under the gas processing category".	Yes.
	Number of plunger lifts and average casing diameter in inches. API asserted that "[t]he final rule adds 40 CFR 98.236(c)(5) requirements to report the number of plunger lifts and average casing diameter in inches by field. The difficulty with these additions is not with the requirement for counting plunger lifts and noting casing diameter, but that reporting must take place at the field level".	Yes.
	Floating Production Storage and Offloading Equipment. API asserted that "[t]he proposed rule did not include floating production storage and offloading equipment in the definition of offshore petroleum and natural gas production. API questions the need for this addition at 40 CFR 98.230(a)(1)".	No.
	Basin level reporting for onshore petroleum and natural gas production. API asserted that "[t]his broad definition of onshore production facility is impractical. Subpart W imposes reporting requirements on over 22,000 entities operating hundreds of thousands of wells and millions of pieces of equipment scattered over hundreds of thousands of square miles".	Yes.
	Field level reporting for onshore petroleum and natural gas production. API asserts that "[t]his level of reporting is problematic when applied to new requirements of the final rule. For the same reasons, it remains problematic when applied to those requirements in the proposed rule that remain in the final rule".	Yes.
	Designated Representative of Subpart W Facility. API asserted that "[t]he new basin-level facility definition for onshore petroleum and natural gas production systems adopted in Subpart W adds unreasonable complexity to several of the existing administrative requirements for the designated representative set forth in 40 CFR 98.4".	Yes.

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Reporting of GHG emissions from leased, rented, or contracted activities. API asserts that "[t]hese requirements create significant complications. A single well pad may be owned by one entity, operated by another entity, lease portable equipment from a third entity, and have that portable equipment operated by yet another entity. The rule places the burden of reporting entirely on the owner of the well or the holders of the operating permit and makes the designated representatives legally responsible for the accuracy of the emissions data provided by third parties".	Partially.
	Threshold for "small" size units that are exempt from consideration. API asserts that "[t]he final rule's threshold of 0.4 MMscf per day for dehydrator calculations using software and individual reporting is too low".	No.
Gas Processors Association by Letter Dates February 11, 2011.	Best Available Monitoring Methods. GPA asserted that "[s]ubpart W's best available monitoring method provisions do not provide reporting entities with adequate time to ensure compliance with the final rule".	No. This is being addressed in a separate action (76 FR 37300).
	Compressor venting monitoring requirements. GPA asserted that "[c]urrent compressor venting monitoring requirements are overly burdensome and present significant safety and operational process concerns to reporting entities".	No.
	Use of the terms "gathering lines" and "booster stations" not being defined in final rule. GPA asserted that "[t]he terms 'gathering lines' and 'booster stations' are not defined in the final rule, nor is sufficient detail provided regarding the definition of 'gas processing facility.'" GPA further asserted that "[a]bsent such definitions and clarifications, there will be substantial confusion as to which facilities are required to report emissions data".	Yes.
	Facility definition for onshore petroleum and natural gas production. GPA asserted "[t]he definition of a facility in Subpart W differs from the definition of a facility provided in all other applicable regulations under the Clean Air Act. This inconsistency will create unnecessary confusion among related programs and is not necessary or justified".	No.
Southwest Gas Corporation by Letter Dated January 31, 2011.	Terms in Subpart W. Southwest Gas Corporation asserted that "[t]he USEPA's final rule fails to provide clear definitions that can be used uniformly throughout the natural gas distribution industry".	Yes.
	Errors in Calculations. Southwest Gas Corporation asserted that the USEPA published errors in equations in 40 CFR 98.233, namely equation W–32.	Yes.
Interstate Natural Gas Association of America ..	Best Available Monitoring Methods	No. This is being addressed in a separate action (76 FR 37300).

TABLE 2—PETITIONS FOR RECONSIDERATION—Continued

Petitioner and date of letter	Issue raised for reconsideration	Is this issue addressed in this action?
	Technical Provisions in Subpart W. INGAA asserted that "[n]umerous technical elements of Subpart W remain unclear, confusing, overly complicated or conflicting".	Partially.
	INGAA petitioned EPA to reconsider the default gas compositions and requested the use of separate default gas compositions for methane and CO_2 for vented and fugitive emissions for the natural gas transmission compression and storage segments.	Yes.
	INGAA petitioned EPA to reconsider minor clarifications to 40 CFR 98.233(t), (u), and (v) for clarity.	Yes.
	INGAA requested EPA to reconsider the provisions in the final rule for determining the type of pneumatic device at a facility. INGAA requested EPA to consider the option of using engineering estimates to determine the type of pneumatic devices.	Yes.
	INGAA requested EPA to reconsider the provisions in the rule related to blowdown vent stacks and requested a reconsideration of those provisions.	Yes.
	INGAA requested EPA to reconsider the provisions in the rule for emissions from blowdown vent stacks and to include an additional equation to allow facilities who currently track emissions by equipment type to submit emission to EPA in that manner.	Yes.
	INGAA requested that EPA to reconsider provisions related to flaring.	Yes.
	INGAA requested that EPA reconsider provisions for monitoring emissions from centrifugal and reciprocating compressors and to consider including clarifications to rule text.	No.
	INGAA requested EPA to reconsider provisions related to monitoring and QA/QC requirements including provisions for the alternative work practice.	Yes.
	INGAA requested EPA to reconsider missing data provisions and broaden access.	No.
	INGAA requested EPA to reconsider provisions as stated in 40 CFR 98.236 and requested several clarifications to final text.	Partially.

The proposed amendments in this action include technical corrections and clarifications to ensure that the 2010 final rule is implemented as intended. Amendments to subparts I and W are also being proposed in other actions. Please see 76 FR 47392 (Herein referred to as the "technical corrections rule") and 76 FR 37300. This proposal complements these proposed rules and is not intended to duplicate or replace those proposed amendments. In limited cases, an amendment to subpart W was proposed in the technical corrections rule and we are proposing to amend it further in this action. Additional proposed amendments were determined to be necessary to address questions and issues raised by stakeholders since development of the proposal of the technical corrections rule. Where amendments have been made to the same paragraph in this action and in the technical corrections rule, the proposal below provides the complete proposed amendatory language for how EPA proposes to amend the provision. We are seeking public comment only on the issues specifically identified in this proposal for the identified subparts. We will not respond to any comments addressing other aspects of part 98 or any other related rulemakings.

EPA promulgated confidentiality determinations for certain data elements required to be reported under part 98 and finalized amendments to the Special Rules Governing Certain Information Obtained Under the Clean

Air Act, which authorizes EPA to release or withhold as confidential reported data according to the confidentiality determinations for such data without taking further procedural steps (76 FR 30782, May 26, 2011 hereinafter referred to as the ''May 26, 2011 Final CBI Rule''). That notice addressed reporting of data elements in 34 subparts that were determined not to be inputs to emission equations and therefore were not proposed to have their reporting deadline deferred. That rule did not make confidentiality determinations for eight subparts, including subpart W, for which reporting requirements were finalized after publication of the July 7, 2010 CBI proposal and July 20, 2010 supplemental CBI proposal.

EPA is planning to address the confidentiality determinations for the data elements in subpart W in a separate action. EPA plans to issue and finalize the confidentiality determinations for subpart W prior to the 2012 reporting deadline.

C. Legal Authority

EPA is proposing these rule amendments under its existing CAA authority, specifically authorities provided in section 114 of the CAA.

As stated in the preamble to the 2009 Final Greenhouse Gas Reporting Rule (part 98) (74 FR 56260, October 30, 2009), CAA section 114 provides EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to EPA's carrying out a wide variety of CAA provisions. As discussed in the preamble to the initial proposed rule (74 FR 16448, April 10, 2009), section 114(a)(1) of the CAA authorizes the Administrator to require emissions sources, persons subject to the CAA, manufacturers of control or process equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA. For further information about EPA's legal authority, see the preambles to the proposed and 2009 final part 981.[1]

D. How would these amendments apply to 2012 reports?

EPA is planning to address the comments on these proposed amendments and publish the final amendments before the end of 2011. Therefore, for subpart W, reporters would be expected to calculate emissions and other relevant data for the reports that are submitted in 2012 using part 98, as amended by this rule, as finalized. We have determined that it is feasible for the sources to implement these changes for the 2011 reporting year since the proposed revisions primarily provide additional clarifications or flexibility regarding the existing regulatory requirements, generally do not affect the type of information that must be collected, and do not substantially affect how emissions are calculated.

For amendments being proposed today to subpart I, EPA is requesting comment on whether to require electronics manufacturing facilities to estimate and report 2011 emissions in 2012 for HTFs that would be newly included in the scope of subpart I if today's proposed rule amendments were finalized.

For facilities subject to the provisions in 40 CFR part 98—subpart W, many proposed revisions simply provide additional information and clarity on existing requirements. For instance, we are proposing to amend 40 CFR 98.1(c)(1) to clarify that for onshore petroleum and natural gas facilities, the references in 40 CFR 98.4 that apply to owner(s) and operator(s) refer to the onshore petroleum and natural gas production owner or operator, as defined in 40 CFR 98.238. Therefore, we are proposing to explicitly make this clarification in 40 CFR 98.1 (Purpose and Scope). The proposed amendment does not change the burden of the 2010 final rule, and in fact, EPA believes that it alleviates concerns expressed by industry that the designated representative provisions are overly burdensome.

Some of the proposed amendments for subpart W provide greater flexibility or simplified calculation methods for certain facilities. For example, we are proposing to amend 40 CFR 98.233(i) to provide an additional option to calculate GHG emissions from blowdown vent stacks. Specifically, we are proposing to allow reporters the option of tracking blowdowns by each occurrence for the same blowdown volume, consistent with current practice at some facilities, whereas in the final rule, reporters were required to track total blowdown vent emissions from all occurrences for the same blowdown volume in a year.

Further, some proposed amendments for subpart W are to the data reporting requirements to provide additional clarity on which GHG emissions have to be reported and at which level of aggregation. For example, in 40 CFR 98.236 EPA is proposing to clarify where ''vented'' emissions should be reported separately from ''flared'' emissions and that reporting of CH_4, CO_2, and N_2O emissions should be reported individually for each source type in CO_2e. We have concluded that amendments such as these could be implemented for the reports submitted to EPA in 2012 because the proposed changes are, with one exception, consistent with the calculation methodologies already in part 98 and the owners or operators are not required to actually report until March 2012,[2] several months after we expect this proposal to be finalized.

The one exception where both the underlying calculation requirements and reporting requirements in subpart W are proposed to be changed is related to the requirements for field level reporting for four emissions sources in the onshore petroleum and natural gas production segment. As described further in Section II.C of this preamble, we are proposing to amend the calculation and reporting requirements for well completions and well workovers, well venting for liquids unloading, and storage tanks to require calculations and reporting to be undertaken at the county level and by geologic formation (by formation type).

EPA believes that the proposed amendments for subpart W can still be implemented for the 2011 reporting year for a couple of reasons. First, these amendments are being proposed based on industry concern about associating wells with a particular ''field'' given possible ambiguity surrounding EIA field designations. While EPA maintains its belief that reporting by the field is a viable and workable option, however, EPA does acknowledge that counties are readily identifiable, and provide clear geographic boundaries. AS a result, implementation of this alternative method should be straightforward for facilities. Second, if facilities are concerned about their ability to implement these provisions for the 2011 reporting year, they may use best available monitoring methods (BAMM) pursuant to 40 CFR 98.234(f). In the event that facilities have already taken a measurement at the field level, they could still use those same measurements for the 2011 reporting year, but apply them to the sub-basin categories based on BAMM.

[1] 74 FR 16448 (April 10, 2009) and 74 FR 56260 (October 30, 2009).

[2] EPA has proposed to extend the 2012 reporting deadline for source categories first required to begin data collection in 2011 from March 31, 2012 to September 28, 2012. Please see the technical corrections rule previously referenced.

Other amendments to subpart W are proposed to address issues identified as a result of working with the affected facilities during rule implementation. These proposed revisions provide additional flexibility to the sources, or reduce the reporting burden. For example, the 2010 final rule required leak detection for emissions from dump valves in transportation storage tanks, and if a leak is detected, measurement of the quantity of emissions would be required. However, industry raised questions as to whether a facility could forgo leak detection and directly measure the emissions from leaking dump valves under the natural gas transmission industry segment. This action provides this additional flexibility, because it reduces burden without compromising the quality of the data reported to EPA.

We are also proposing corrections to terms and definitions in certain equations in subpart W. For example, we are proposing to amend the calculation for estimating CO_2 emissions from acid gas removal vents in Equation W–4. Although the existing equation is appropriate when the amount of CO_2 in gas is relatively low, such as 1 percent, the error rate in the estimate increases significantly as the amount of CO_2 in gas increases. Therefore, EPA is proposing a new equation, which uses the exact same input parameters and thus will not result in any additional burden to reporters, but will improve the quality of the information submitted to EPA. These clarifications do not result in additional requirements; therefore, we have concluded that reporters can follow part 98, as amended, in submitting their first reports to EPA in 2012.

Finally, we are proposing other technical corrections in subpart W that have no impact on a facility's data collection efforts in 2011. For example, we are proposing to correct cross references in equations and change incorrect use of the term ''facility'' in the definition of the source category.

In summary, these proposed amendments to subpart W generally would not require any additional monitoring or information collection above what is already included in part 98. Therefore, we expect that sources can use the same information that they have been collecting under the current version of part 98 to calculate and report GHG emissions for 2011 and submit reports in 2012 under Part 98, as amended by this action.

We seek comment on whether it is appropriate to implement these amendments and incorporate the requirements in the data reported to EPA by March 31, 2012. Further, we seek comment on whether there are specific provisions in subpart W for which this timeline may not be feasible or appropriate due to the nature of the proposed changes or the way in which data have been collected thus far in 2011. We request that commenters provide specific examples of how the proposed implementation schedule would or would not work.

II. Technical Corrections and Other Amendments

Following promulgation of the 2010 final subpart I and subpart W, EPA has identified errors in the regulatory language that we are now proposing to correct. These issues were identified as a result of working with affected industries to implement rules. We have also identified certain rule provisions that should be amended to provide greater clarity. For additional background information on the questions raised, please refer to the Technical Support Document for this proposed rulemaking available in the docket to this rulemaking (EPA–HQ–OAR–2011–0512).

The amendments we are now proposing include the following types of changes:

- Changes to correct cross references within the subparts.
- Additional information to allow reporters to better or more fully understand compliance obligations in a specific provision.
- Corrections to terms and definitions in certain equations.
- Corrections to data reporting requirements so that they more closely conform to the information used to perform emission calculations.
- Other amendments related to certain issues identified as a result of working with the affected sources during rule implementation and outreach.

We are seeking public comment only on the issues specifically identified in this notice for the identified subparts. We will not respond to any comments addressing other aspects of part 98 or any other related rulemakings.

A. Subpart A—General Provisions

Designated Representative. Two industry associations raised concerns about the provisions related to determination of the designated representative in the context of how the subpart A definition would affect subpart W reporters. Through a letter dated January 31, 2011, the American Petroleum Institute (API) encouraged EPA to reconsider the implications on owners and operators in the onshore petroleum and natural gas production segment in the context of the provisions in 40 CFR 98.4. Specifically, API was concerned that given the definition of ''facility'' for onshore petroleum and natural gas production, coupled with the relatively complex ownership structures in the industry (as compared to other subparts covered under part 98), EPA should modify several requirements in 40 CFR 98.4 (authorization and responsibilities of the designated representative). API encouraged EPA to eliminate the requirement of notifying co-owners of the designated representative selection (40 CFR 98.4(i)(4)(iv)), eliminate the requirement for listing of co-owners as part of the certificate of representation (40 CFR 98.4(i)(3), and eliminate the requirement for new certificates of representation following ownership changes (40 CFR 98.4(h)).

Similar concerns were expressed in a letter from Chesapeake Energy Corporation (CEC) and the American Exploration & Production Council (AXPC) dated January 31, 2011. CEC/AXPC was also concerned that the current operational reality in the onshore petroleum and natural gas industry would make it difficult for a designated representative to make the certifications required in 40 CFR 98.4(i)(4). Specifically, CEC/AXPC was concerned about attesting to the fact that the designated representative was selected by an agreement binding on the owners and operators of the facility, that all owners and operators are fully bound by representations of the designated representative, that the owners and operators of the facility would be bound by any order issued to the designated representative by the administrator or a court, and that the designated representative has given written notice of their selection and of the agreement by which the designated was selected by the owner and operator of the facility.

EPA maintains, as described in the October 2009 final rule (74 FR 56357), that the high level of public interest in the data collected under this rule, as well as its importance to future policy, warrants establishment, by rule pursuant to CAA sections 114, 208, and 301(a)(1), of a high standard for data quality and consistency and a high level of accountability for reported data, which will help ensure that the data quality and consistency standard is met. The designated representative is the primary point of contact between the owner or operator and the EPA. Therefore, it is important that EPA knows who the designated representative is, and that the designated representative has made the necessary certification statements.

EPA recognizes that the onshore petroleum and natural gas industry has a different organizational structure and operational realities than other industries subject to part 98. As such, in the 2010 final rule for subpart W (75 FR 74512), EPA specifically defined who is an onshore petroleum and natural gas production owner or operator. Under 40 CFR 98.238, onshore petroleum and natural gas production owner or operator means ''the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in 40 CFR 98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the state or federal business income taxes is considered the owner or operator.'' It was EPA's intent that this definition of owner and operator apply not only in subpart W, but also in subpart A for the obligations of Subpart W ''owners and operators'' (*e.g.*, those related to identifying the designated representative and requirement for who must be included on the Certificate of Representation (COR)).

EPA acknowledges that the final subpart W rule is not clear, and it could be interpreted that all ''owners'' and all ''operators'', as defined in 40 CFR 98.6, are required to identify the designated representative for the facility and be held accountable for all requirements under 40 CFR 98.4. EPA never intended that 4,000 owners and operators, *e.g.*, would have to be listed on the COR, an example provided by API in their Petition for Reconsideration. Rather, EPA intended that for onshore petroleum and natural gas facilities, the references in 40 CFR 98.4 that apply to owner(s) and operator(s) refer to the onshore petroleum and natural gas production operator, as defined in 40 CFR 98.238. Therefore, we are proposing to explicitly make this clarification in 40 CFR 98.1 (Purpose and Scope).

Definitions: We are proposing amendments to the definition of continuous bleed pneumatic device in 40 CFR 98.6 to clarify that continuous bleed devices supply gas to process control devices; these are not necessarily measurement devices, as suggested by the 2010 final rule.

Similarly, we are proposing to amend the definition of an intermittent bleed pneumatic device to clarify that these devices automatically maintain the process conditions and that the devices discharge all or a portion of the full volume of the actuator intermittently.

Incorporation by Reference (IBR). Finally we are also proposing to amend 40 CFR 98.7 (What standardized methods are incorporated by reference into this part?) to remove paragraph 40 CFR 98.7(q). As elaborated further below, we are proposing to change the calculation and reporting requirements for specific equipment in the onshore petroleum and natural gas production segment from a ''field'' level, to a sub-basin category. Consistent with this proposed amendment, there is no longer a need to incorporate the Energy Information Administration (EIA) Oil and Gas Field Code Master List, 2008.

B. Subpart I—Electronics Manufacturing

In this action, EPA is proposing to amend the provisions contained within subpart I to calculate and report emissions from fluorinated GHGs used as HTFs. First, EPA is proposing to amend the definition of HTFs in 40 CFR 98.98, to include all fluorocarbons used as HTFs in the electronics manufacturing industry. The definition of HTFs incorporates the term ''fluorinated GHGs'' as defined in the general provisions of the greenhouse gas reporting rule (subpart A) at 40 CFR 98.6. The definition of ''fluorinated greenhouse gas'' in subpart A excludes ''substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C.'' EPA is proposing to specify that the vapor pressure cutoff clause in the subpart A definition of fluorinated GHGs does not apply to fluorinated HTFs in subpart I. As a result, emissions of fluorinated HTFs with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C would no longer be excluded from reporting under subpart I. Second, also in the definition of HTFs, EPA is proposing to add the phrase ''but not limited to'' before listing examples of fluorinated HTFs to ensure that potential future alternatives are covered. Third, EPA is proposing to remove the last sentence in the definition (''Electronics manufacturers may also use these same fluorinated chemicals to clean substrate surfaces or other parts'') and move the concept of using HTFs to clean substrate surfaces or other parts to the first sentence. Fourth, EPA is proposing minor revisions throughout the subpart I regulatory text to clarify the use of the terms fluorinated GHGs and fluorinated HTFs (*e.g.*, referring to fluorinated HTFs rather than fluorinated GHGs used as HTFs). And last, in 40 CFR 98.92(a)(5), under GHGs to report, EPA is proposing to revise the clause ''fluorinated GHG emitted from heat transfer use'' to read ''emissions of fluorinated heat transfer fluids.''

EPA published Subpart I: Electronics Manufacturing of part 98 on December 1, 2010 (75 FR 74774). This subpart requires monitoring and reporting of GHG emissions from electronics manufacturing. Included in the December 1, 2010 final rule are provisions that require electronics manufacturing facilities to calculate and report emissions from the use of fluorinated HTFs. Pursuant to 40 CFR 98.93(h), electronics manufacturing facilities must calculate HTF emissions using a mass balance approach based on: the beginning and end of year inventories; acquisitions and disbursements of HTFs; and the nameplate capacities of newly installed and removed equipment containing HTFs. For purposes of subpart I, HTFs are defined as the following: ''fluorinated GHGs used for temperature control, device testing, and soldering in certain types of electronic manufacturing production processes. HTFs used in the electronics sector include perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers. Electronics manufacturers may also use these same fluorinated chemicals to clean substrate surfaces and other parts'' (40 CFR 98.98).

The definition of HTFs in subpart I includes the term ''fluorinated greenhouse gases'' (fluorinated GHGs), which is defined in subpart A: General Provisions (40 CFR 98.6). EPA initially proposed a definition of fluorinated GHGs in the April 2009 proposed rule for part 98 (74 FR 16448) as follows: ''Fluorinated GHG means sulfur hexafluoride (SF6), nitrogen trifluoride (NF3), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A. In addition to (SF6) and NF3, ''fluorinated GHG'' includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.''

EPA received numerous comments on the definition, particularly in regards to Subpart OO–Suppliers of Industrial GHGs. For example, some commenters argued that the proposed definition of fluorinated GHGs was too broad because it would include nonvolatile materials that could not be emitted to the atmosphere. More specifically, one commenter suggested establishing a lower vapor pressure limit for fluorinated GHGs (heat transfer fluids) of 400 Pa (0.004 bar, or three mm Hg absolute) at 25 C.[3]

In response to comments, in the 2009 final part 98 (74 FR 56260), EPA finalized the following definition of fluorinated GHG: ''Fluorinated GHG means sulfur hexafluoride (SF6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, ''fluorinated GHG'' includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.'' As EPA stated in the preamble to the final rule, ''This modification ensures that non-volatile fluorocarbons such as fluoropolymers are excluded from reporting requirements, while requiring reporting of fluorocarbons (as well as SF_6 and NF_3) that could reasonably be expected to be emitted to the atmosphere'' (74 FR 56348, October 30, 2009).

EPA proposed the subpart I definition for HTFs, which included the term ''fluorinated GHG,'' in an April 12, 2010 **Federal Register** notice (75 FR 18652). In a December 1, 2010 final rule ''Mandatory Reporting of Greenhouse Gases: Additional Sources of Fluorinated GHGs'' (75 FR 74775), EPA finalized a definition for HTFs that was substantially similar to the definition in the April 2010 proposed rule.

Following publication of the final rule, 3M Company (3M) sought reconsideration of the reporting requirements for fluorinated GHGs used as HTFs under subpart I. Specifically, in its Petition for Reconsideration dated January 28, 2011 (available in docket EPA–HQ–OAR–2009–0927), 3M stated that ''* * * as currently written the reporting requirements for heat transfer fluids will exclude a significant portion of fluorinated GHGs used as heat transfer fluids. Thus, the GHG emissions associated with heat transfer fluids will not be accurately reported under the rule.'' Further, 3M stated, ''By tying the reporting requirements for heat transfer fluids to the definition of a fluorinated GHG under § 98.6 in Subpart A, the scope of Subpart I's reporting requirements are limited to those heat transfer fluids that have vapor pressures of > 1 mmHg at 25 degrees C. Although 3M understands the reasons behind the vapor pressure threshold in the general definition of a fluorinated GHG, the same rationale should not apply to heat transfer fluids. Heat transfer fluids are used at elevated temperatures and pressures, and as a result the vapor pressure of these materials at 1 mm Hg absolute T 25 degrees C is not predicative of emissions. Heat transfer fluids are used through a broad range of boiling points and are routinely lost from systems primarily through mechanical leaks but also from evaporative loss. Once emitted from a system, the fate of heat transfer fluids is primarily the atmosphere.''

In addition to the concern that the rule will result in ''dramatic under reporting of heat transfer fluid use and emissions,'' 3M also raised the concern that ''although all the heat transfer fluids that have relatively low global warming potentials will be required to be reported as GHGs, a substantial percentage of heat transfer fluids that have global warming potentials in the range of 10,000 times that of CO_2 will be exempt from reporting requirements.'' Consequently, 3M argued, ''the rule will likely lead to a migration toward use of exempt compounds and an increase in GHG emissions from the sector.''

To address the problem, 3M suggested that subpart I should be amended to specify that for reporting requirements under subpart I, the vapor pressure cutoff in the general definition of fluorinated GHG does not apply to HTFs.

In finalizing the HTF provisions in subpart I, EPA did not intend to exclude a significant portion of fluorocarbon HTFs that can enter the atmosphere; any such exclusion was inadvertent. Given the high temperatures in which HTFs may be used, EPA believes that such fluids are able to enter the atmosphere even when their vapor pressures at 25 degrees C (77 degrees F) are low. This is because the vapor pressures of substances increase as their temperatures increase, and HTFs with low vapor pressures are likely to be used in high-temperature applications.[4] (Vapor pressure is an indicator of the rapidity with which a substance evaporates.) For example, an HTF with a vapor pressure of about 0.2 mm Hg at 25 degrees C might be used at a temperature of 140 degrees C for heat transfer applications, where it may have a vapor pressure of over 80 mm Hg. Similarly, an HTF with a vapor pressure of about 0.1 mm Hg at 25 degrees C might be used for vapor phase soldering at a temperature above its boiling point. Under these conditions, all of the material is in the vapor phase. Supporting technical information is available in the docket (EPA–HQ–OAR–2011–0512).

EPA understands that at any particular temperature, an HTF with a low vapor pressure at 25 degrees C is likely to evaporate more slowly than an HTF with a higher vapor pressure at 25 degrees C. Nevertheless, if the temperature is high, evaporation will occur.

EPA views data on emissions of HTFs as an important component in improving future efforts to characterize GHG emissions from the electronics manufacturing sector. EPA believes that the changes being proposed today will ensure that all fluorinated HTFs used in electronics manufacturing are appropriately monitored and reported under subpart I.

In this action, EPA is proposing that the definition of HTFs in subpart I be revised to read as follows: ''Fluorinated heat transfer fluids means fluorinated GHGs used for temperature control, device testing, cleaning substrate surfaces and other parts, and soldering in certain types of electronics manufacturing production processes. For fluorinated heat transfer fluids under this subpart I, the lower vapor pressure limit of 1 mm of Hg in absolute at 25 degrees C in the definition of ''fluorinated greenhouse gas'' in 40 CFR 98.6 shall not apply. Fluorinated heat transfer fluids used in the electronics manufacturing sector include, but are not limited to, perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers.''

The effect of making the vapor pressure cut-off portion of the definition of fluorinated GHGs inapplicable to fluorinated HTFs under subpart I would be to subject emissions from fluorinated HTFs that have vapor pressures less than one mm of Hg absolute at 25

[3] For more information on comments and responses, please see the preamble to the final rule Mandatory Reporting of Greenhouse Gases (74 FFR 56348), and the Response to Public Comment on subpart OO (''Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, subpart OO: Suppliers of Industrial GHGs'' available in docket, EPA–HQ–OAR–2008–0508.)

[4] HTFs are selected for particular applications based on their viscosities within operating temperature ranges and/or their boiling points. For example, for liquid phase applications (*e.g.,* some cooling applications) HTFs are selected that have boiling points above the operating temperature range and low viscosities at the lower operating temperatures. As temperature decreases, viscosity increases. Low viscosities are more desirable because they will provide good heat transfer and will be easily pumped. For higher temperature applications, such as vapor phase soldering, HTFs with low vapor pressures—at room temperature (high boiling points) are generally selected. (See, *e.g.,* ''Fluorochemicals in Heat Transfer Applications: Frequently Asked Questions,'' 3M, available in the docket for this rulemaking.)

degrees C to the reporting requirements. Consequently, EPA would receive valuable emissions information on the full range of volatile fluorinated HTFs used in electronics manufacturing.

The purpose of the Mandatory Reporting Rule is to collect accurate facility-specific GHG emissions data for use in developing future GHG policies and programs. For this reason, EPA believes that the definition of HTFs being proposed today is prudent and appropriate because it will provide EPA with comprehensive information on emissions of fluorinated HTFs. Considering the simple mass balance methodology required for reporting emissions of fluorinated HTFs in subpart I, the potential value of this information justifies a comprehensive definition. If some HTFs (or HTFs in some currently included applications) are found to have very low emission rates, this information will itself be valuable for informing future GHG policies. However, given that HTFs are capable of entering the atmosphere at the temperatures where they are used, any conclusion that the emissions of some HTFs are low must be supported by actual measurements.

EPA considered including a modified vapor pressure limit in the proposed definition of HTF. One approach we considered was to adopt a vapor pressure limit associated with a particular temperature higher than 25 degrees C. The goal of such a limit would be to require reporting of those HTFs that may readily enter the vapor phase in their current and potential future applications. However, we believe that today's proposed, application-based definition achieves this goal more simply and effectively than would a definition that includes a vapor pressure limit associated with a particular temperature higher than 25 degrees C. First, given the breadth of conditions under which HTFs are used currently in the electronics industry, as well as the rapidity of technological change within this industry, it would be difficult to specify an appropriate upper-limit temperature to which to link the vapor pressure. Some applications occur at very high temperatures, and those temperatures could conceivably rise in the future. Second, such a limit, if not linked to particular HTF applications, could include fluorinated chemicals that are used exclusively in low-temperature applications where they would not quickly enter the atmosphere if released, such as certain lubricants or oils. Third, the major application of HTFs is for process cooling. In this application, as discussed above, HTFs with lower vapor pressures at a particular temperature are likely to be used at higher temperatures. This is a systematic relationship that almost guarantees that the HTF will be capable of volatilizing at the temperature of use. Similar relationships are likely to hold in other applications where viscosity or boiling point is a concern, *e.g.*, thermal shock testing. Finally, other applications, such as substrate cleaning or vapor phase soldering, occur when the material is in the vapor phase. Any upper-bound temperature linked to a vapor pressure would have to fall above the temperatures where vapor phase soldering occurs. The proposed definition achieves the same goal much more directly by including the applications ''soldering,'' ''temperature control,'' ''device testing,'' and ''cleaning substrate surfaces.''

Another approach we considered was to require reporting only of HTFs that achieve a particular vapor pressure (*e.g.*, 1 mm Hg absolute) at their maximum temperature of use, where the maximum temperature of use could vary from facility to facility or even application to application within a facility. This approach would explicitly focus monitoring and reporting on those HTFs and applications where volatilization could occur. However, because the coverage of particular chemicals would depend on their maximum temperature of use within a particular facility or application, this approach would be significantly more difficult to implement and enforce than the proposed, application-based definition. Facilities would be required to investigate the temperatures at which each HTF is used and to distinguish between low- and high-temperature applications of the same HTF in developing emissions estimates. The proposed approach, in contrast, would clearly define the applicability of the rule and would enable facilities (and EPA) to rely on facility-wide mass-balances to estimate emissions of particular chemicals.

EPA does not intend for its definition of HTFs to include greases or lubricants such as those used in vacuum pump applications because such applications do not typically occur at temperatures at which the lubricants would volatilize. EPA does not believe that the current or proposed definitions include such lubricants. However, EPA requests comment on whether the definition should be amended to explicitly exclude lubrication or other applications. To address situations in which a particular chemical may be used in both HTF and non-HTF applications, EPA also requests comment on whether we should give reporters flexibility to report under 40 CFR 98.93(h) either a chemical's emissions from all applications or its emissions from only the applications included in the HTF definition. This would give facilities the option to avoid maintaining a separate supply of the chemical for purposes of tracking HTF emissions, as would otherwise be required for the mass-balance calculation. Emissions from the non-HTF applications would presumably make up a small fraction of the total.

The narrow exception to the vapor pressure cutoff would only apply to fluorinated HTFs used in the electronics manufacturing industry; EPA continues to believe that the vapor pressure cutoff is appropriate to maintain in the definition of fluorinated GHG in 40 CFR 82 subpart A (*e.g.*, for purposes of the industrial gas supply provisions at subpart OO). EPA is not aware of other fluorocarbon applications in which the vapor pressure of the fluorocarbon falls below 1 millimeter of Hg at 25 degrees C but typically rises significantly above it at the temperature of use.

In addition, EPA is also proposing four other minor amendments to the regulatory text related to fluorinated HTFs. First, in the definition of HTF (40 CFR 98.98), EPA is proposing to add the phrase ''but not limited to'' before listing examples of fluorinated HTFs. Electronics manufacturing is an innovative and quickly evolving industry in which new chemicals are frequently adopted. EPA is proposing this change to ensure that potential future alternatives are covered. Second, also in the definition of HTFs (40 CFR 98.98), EPA is proposing to delete the last sentence (''Electronics manufacturers may also use these same fluorinated chemicals to clean substrate surfaces or other parts'') and move the concept of cleaning substrates surfaces or other parts to the first sentence. EPA is proposing this change to improve readability of the definition. Third, EPA is proposing minor revisions throughout the subpart I regulatory text to clarify the use of the terms fluorinated GHGs and fluorinated HTFs (*e.g.*, referring to fluorinated HTFs rather than fluorinated GHGs used as HTFs). For example, in instances where EPA used the term ''fluorinated GHG used as heat transfer fluids,'' EPA is proposing to use ''fluorinated heat transfer fluids.'' Where EPA refers to HTFs, EPA does not intend the full definition of fluorinated GHGs (as defined in subpart A) to apply. And last, in 40 CFR 98.92(a)(5), under GHGs to report, EPA is proposing to revise the clause ''fluorinated GHG emitted from heat transfer use'' to read ''emissions of fluorinated heat transfer fluids.'' EPA is proposing this change to clarify that emissions of fluorinated HTFs, not just fluorinated GHGs, are required to be reported under subpart I. In addition, EPA is proposing the change to clarify the Agency's intention that emissions from HTFs can occur through all phases of the equipment's lifetime, including installation, use, servicing, and disposal. Under subpart I, all of those emissions of HTFs should be calculated and reported.

EPA does not anticipate an increase in burden resulting from these proposed changes because this action is clarifying the intent of the requirements finalized in subpart I. In finalizing the reporting requirements for fluorinated HTFs, EPA did not intend to exclude fluorocarbons that can enter the atmosphere under the conditions in which HTFs are used in the electronics manufacturing industry. EPA's burden estimates were based on reporting of all fluorinated HTFs; therefore, the clarification of intent does not impose additional burden on reporters.

EPA requests comment on the proposed amendments to the HTF provisions of subpart I. In particular, EPA requests comment whether the proposed definition effectively captures fluorinated HTFs used in electronics manufacturing (*i.e.*, whether any type of fluorinated HTFs other than those included in the proposed definition are currently being used or are anticipated to be used in the future for electronics manufacturing). EPA also requests comment on whether any other conforming changes need to be made.

EPA plans to address the comments on these proposed amendments and publish the final amendments to subpart I before the end of 2011. Therefore, EPA requests comment on whether to require electronics manufacturing facilities to estimate and report 2011 emissions in 2012 of the HTFs that would be newly included in the scope of subpart I if today's proposed rule were finalized. Specifically, EPA requests comment on whether information collected as part of routine business practices, such as records of HTF stocks, disbursements, and acquisitions, could be used to estimate 2011 emissions to be reported in 2012. If it is not feasible to estimate HTF emissions in 2011 for substances that are currently excluded from reporting using information collected as part of routine business practices, EPA requests detailed information illustrating why it is not feasible.

C. Subpart W—Petroleum and Natural Gas Systems

EPA is proposing several technical clarifications and amendments to subpart W to address issues raised during the first year of promulgation of the rule in response to petitions submitted to EPA for reconsideration, as well as clarifications to specified provisions in the rule to ensure consistency with subpart W, and across all subparts, where appropriate. In addition, several technical corrections are proposed to clarify provisions that were either erroneous or unclear to reporters.

The following section describes EPA's proposed amendments. We first discuss the proposed amendments related to field-level reporting in the onshore petroleum and natural gas production section, since this proposed amendment affects multiple emissions sources (well completions, well workovers, well venting for liquids unloading, and onshore storage tanks) and also affects many sections of the rule (*e.g.*, calculation, monitoring and quality assurance/quality control (QA/QC), and the data reporting requirements). Following the discussion for onshore production, we discuss the proposed amendments to the Definition of the Source Category (40 CFR 98.230), GHG's to Report (40 CFR 98.232), Calculating GHG Emissions (40 CFR 98.233), Monitoring and QA/QC Requirements (40 CFR 98.234), Data Reporting Requirements (40 CFR 98.236) and Records to be Retained (40 CFR 98.237) under subpart W.

Sub-Basin Category for Onshore Petroleum and Natural Gas Production. EPA has received several requests to reconsider the use of a field-level measurement plan for emission sources (mainly monitoring of GHGs from well unloading, well completions, and well workovers) that require one measurement per field as designated by the U.S. Energy Information Administration (EIA) Field Code Master List (FCML). Onshore petroleum and natural gas production reporters have expressed concerns over the use of this field designation and proposed that a sub-basin category be assigned instead of a field designation to take measurements. Specifically, petitioners indicated that EPA has not clarified how reporting entities are supposed to map wells to a particular field. They contested that there are no coordinates provided in the EIA FCML 2008. They also suggested there is no formal way to designate appropriate field names and the rule does not have a mechanism to deal with wells that are not in a recognized field in the EIA Master List. Mapping wells to the proper field is central to compliance with the rule, they assert, because the rule requires aggregation of information by field for the different emissions sources. To address these concerns, industry petitioned EPA to replace the field-level approach with a ''sub-basin category'' approach.

In general, EPA continues to believe that the field-level designation is workable, although perhaps not the only means of obtaining representative emissions estimates. EPA has determined that the EIA field codes are developed using field names that operators provide and agree on with States, which is finally provided by the States to the EIA. Therefore, EPA believes that operators can determine the EIA field they are in using the EIA field codes. EPA also agrees that the 2010 final rule did not state a clear mechanism to address wells in fields that were not included in the EIA FCML. However, EPA has determined that this is not an acute problem. EPA has analyzed the EIA FCML for several years and found that the changes in the database from year to year are not significant. For example, there were only 30 changes in field definitions between 2007 and 2008 of the total 64,454 fields in the database. Similar numbers result from comparing 2006 with 2007 (170 changes in field definition of a total 63,873 fields in the database) and comparing 2006 with 2005 (44 changes in field definition of a total 63,356 fields in the database). The changes include both the revision of some field names as well as new additions.

In this action we are proposing an alternative approach to replace ''field-level'' with ''sub-basin categories.'' EPA considered, but is not proposing at this time modifications to the current field level reporting method that would address the outstanding concerns raised by industry. Specifically, EPA considered an amendment that would allow reporters to use a temporary field name when submitting reports to EPA in instances where a well does not fall within a designated EIA field code. This alternative approach would include a provision for reporters to report a preliminary field name where a field has not been formally designated by the State and as such may not yet be included in the EIA FCML. These preliminary fields entered by the reporter would be annotated in the final report to EPA and would be flagged in the data system for further follow up to determine the final field name designated by the State. Because States operate on different schedules for which final determinations are made on field designation requests, reporters would be required to certify with official documentation submitted to EPA upon each reporting period on the status of their field designation request. Under this alternate approach, for field designations that are made prior to the next reporting date, reporters should confirm the field designation with official documentation during the next submission of their emission report to EPA. This proposed method would address concerns raised by industry about fields not yet included in the EIA FCML.

In addition, EPA is considering but did not propose a provision that would delineate how reporters would determine appropriate field names for wells for which the designated field is unknown due to unclear location or coordinates of the well. Under such a provision, reporters would determine the EIA FCML field for a given well by determining the well coordinates and follow the procedures outlined in the 2008 EIA FCML or most approximate year's documentation that accompanies the EIA FCML field list which outlines the method for matching up well coordinates with field names. Although EPA is proposing an alternative means to calculate and report emissions based on a sub-basin category, we are seeking comment on this approach to modify the current field-level calculation and reporting requirements for utilizing the EIA FCML for sampling. Although EPA maintains that the current field level calculation and reporting requirements are feasible and provide representative emissions estimates (with an amendment to clarify how to address non-designated fields), EPA is proposing an alternative sub-basin approach that we believe also achieves an appropriate level of representativeness. Please see Economic Impact Analysis Memorandum in Docket ID EPA–HQ–OAR–2001–0512. This proposed sub-basin category classification would provide similar quality data as the EIA FCML designation but believes will also address some of the questions and concerns regarding current implementation of the field-level approach.

The foundation of the proposed sub-basin approach is defining a sub-basin category through the use of a county level designation and the distinction of the type of hydrocarbon formation. The various hydrocarbon formations can be grouped into four categories: conventional, coal bed methane, tight formations, and shale. For example, wells producing coal bed methane from formation ''X'' with wellhead coordinates within county ''A'' would be one sub-basin category. Further, wells producing from tight formation ''Y'' with wellhead coordinates within county ''A'' would be a second sub-basin category. In the event that a specific county includes more than one formation (*e.g.*, coal bed methane and tight sands), then the reporter would use the most specific designation (*e.g.*, coal bed methane).

With this basic formulation of sub-basin category, EPA has determined that it is necessary to provide a second level of classification to get a representative emissions profile of emissions sources. For example, the emissions from well completions or hydraulic fracturing can vary by several multiples within the same producing formation because of different fracture zones and fracture extent. Similarly, well liquids unloading emissions can vary widely because of different well dimensions and liquid accumulation. EPA further notes that the activity of emissions sources are highly concentrated within certain counties and formation types. For example, of the 3,143 counties in the United States, there are only 54 counties that had any form of well completion in year 2010. In such a case, where 25,000 well completions are concentrated in 54 counties, a single measurement from a sub-basin category, may not be sufficiently representative.

Therefore, to obtain a sufficient number of data points to be able to characterize the variability in the emissions profile, EPA is proposing a measurement plan that uses some operational criteria to generate more than one sample per sub-basin category for specific emissions sources. Specifically, EPA is proposing the use of pressure ranges for liquids unloading measurements, because the volume of gas released during an unloading is related to the wellhead pressure. For example, reporters would take one measurement per pressure range within a sub-basin category. An example of pressure ranges is 0–25 psig, > 25–60 psig, > 60–110 psig, > 110–200 psig, and 200 psig and above. These pressure ranges were developed based on an analysis that reviewed well data from the HPDI© database which determined the optimal pressure ranges that also minimize variability of a single data point as a representation of that pressure range. For more information on this analysis, please see the Technical Support Document for this proposed rulemaking in the docket.

The rationale for applying these pressure ranges is that wells generally have more liquids unloading problems when they are flowing at low pressures and lower velocities. Hence, it is reasonable to provide more ranges in the lower pressure spectrum. EPA expects to see few wells over 200 psig that necessitate liquids unloading to atmospheric pressure. For well completions and workovers, EPA is proposing to divide the population of wells between vertical and horizontal wells, as defined in proposed amended 40 CFR 98.238, and then using a graduated number of measurements per number of wells completed or worked over in these categories. For example, one measurement per 25 wells with hydraulic fracture, two measurements per 50 wells with hydraulic fracture, three measurements per 100 wells with hydraulic fracture, and four measurements per 200 or more wells with hydraulic fracture. EPA understands that there are many operational factors that impact the magnitude of emissions from well hydraulic fracture completions and workovers and therefore is proposing more than one measurement where there is a larger number of wells in the sub-basin category.

Source Category Definitions. In general, we are proposing several amendments to the source category definitions to clarify the boundaries between the different industry segments. The proposed amendments below seek merely to clarify coverage in the rule and were not intended to change who is required to report within and across the industry segments.

Onshore Petroleum and Natural Gas Production. We are proposing several amendments to the definition for the onshore petroleum and natural gas production (also referred to as onshore production) industry segment in 40 CFR 98.230(a)(2). EPA received feedback from reporters on the finalized definition for the onshore production industry segment on November 30, 2010 (*see* 75 FR 74489) requesting clarification on the term ''associated with a well-pad.'' Specifically, reporters requested clarification on what the term ''associated with a well-pad'' meant in the context of the boundaries of the onshore production industry segment. Reporters stated that there is unclear demarcation between equipment that are considered part of the onshore production industry segment and equipment that are considered part of the onshore natural gas processing industry segment.

To address concerns on the meaning of ''associated with a well-pad'', EPA is first proposing to revise the term itself to state that the onshore production industry segment includes that equipment that is ''on a single well-pad or associated with a *single* well-pad.'' EPA has determined that equipment located on a *single* well-pad is considered part of the onshore production industry segment irrespective of the hydrocarbon streams that it is handling. For example, a separator located on a well-pad that handles hydrocarbon streams from multiple well-pads would be considered to be part of the onshore production industry segment, i.e. equipment that is not located on a well-pad would be considered to be associated with a well-pad. Also, hydrocarbon streams from multiple wellheads located on a single well-pad is considered to be a single hydrocarbon stream from that well-pad.

In addition, EPA is proposing to clarify in the onshore production industry segment definition that dehydrators that are on a single well-pad or associated with a single well-pad are included as types of equipment that is considered part of this segment. Following promulgation of subpart W in November 2010, EPA received several questions from the reporting community requesting clarification on whether or not dehydrators associated with a single well-pad would be a part of the industry segment. It was EPA's intent that these dehydrators that are on a well-pad or associated with a single well-pad be considered part of the onshore production industry segment. EPA also received similar requests for clarification on whether or not storage vessels, not necessarily the entire storage facility, were also considered part of the onshore production industry segment. To address these concerns, EPA is proposing to clarify in the definition that both dehydrators and storage vessels are included in the equipment list that are considered part of the onshore production industry segment. Finally, EPA proposes to clarify that Enhanced Oil Recovery (EOR) that use either CO_2 or natural gas are a part of the source category. The equipment located on a well-pad is part of the onshore production industry segment irrespective of the hydrocarbon streams located on a well-pad.

Onshore Natural Gas Processing. EPA is proposing several clarifications to the onshore natural gas processing industry segment definition in 40 CFR 98.230(a)(3). By letter dated January 31, 2011, the Gas Processors Association (GPA), CEC/AXPC, and API, all expressed concerns with overlap between the onshore production, onshore natural gas processing, and onshore natural gas transmission industry segments. API stated that ''The definitions of the industry categories 'onshore oil and gas production' and 'natural gas processing' do not provide a clear line between onshore oil and gas production, gas gathering/collection and booster stations, and natural gas processing facilities.'' The letter stated ''API is particularly concerned that the final rule could be interpreted to include gathering and boosting stations in the processing sector, despite EPA's stated intent to exclude gathering and boosting stations from coverage at this time.'' Industry raised concerns that boosting stations would be covered under the finalized natural gas processing industry segment definition because they typically have processes that require removal of liquids for operation of specific equipment that boost gas pressure. For example, scrubbers are used upstream of compressors to take out any liquids for optimal operation of the compression equipment. However, the presence of scrubbers in and of itself should not result in the facility being defined as a processing facility.

To address the concerns with boundaries between industry segments, we are proposing several revisions to clarify our intent. First we are proposing to strike the term ''and recovers'' from the first sentence in order to more clearly characterize the unique activities performed at the processing plant. Processing plants extract heavy hydrocarbons and non hydrocarbon gases from the gaseous phase of an inlet feed to the plant. By inclusion of the term ''recovers'' in the industry segment definition, the natural gas processing plant definition may have been incorrectly interpreted to bring in other types of processes that were not intended to be covered.

We are also proposing to clarify that this industry segment includes one or a combination of the following three processes: Separation of natural gas liquids (NGLs) from natural gas, separation of non-methane gases from produced natural gas, or separation of NGLs into one or more component mixtures. This proposed revision would clarify that the natural gas processing industry segment differs from what typically happens at boosting stations in that natural gas processing plants typically perform one or more of these processes, whereas boosting stations do not.

We are also proposing a clarification on what separation means by stating that separation means one or more of the following processes: Forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams.

We are proposing to strike the term ''this industry segment does not include reporting of emissions from gathering lines and boosting stations'' because the edits proposed above clarify what ''onshore natural gas processing'' means, and therefore it is unnecessary to discuss that which is excluded. Further, if we had decided to maintain the ''gathering lines and boosting'' stations in the rule, EPA would have to propose and finalize a definition of the term ''gathering line and boosting'' station, which EPA has previously noted we intend to consider in a future rulemaking (75 FR 74468).

Finally we are proposing to strike the term ''facility'' and replace it with the term ''plant'' as ''facility'' has a specific definition in 40 CFR 98.6 that was not intended here. A natural gas processing plant may be located at a facility that also contains other source categories covered by 40 CFR part 98.

Onshore Natural Gas Transmission Compression. EPA is proposing several clarifications to the onshore natural gas transmission compression industry segment definition in 40 CFR 98.230(a)(4). As noted earlier, by letter dated January 31, 2011, API, CEC/AXPC, and GPA raised their concerns that the boundaries between the onshore production, onshore natural gas processing, and onshore natural gas transmission compression industry segment boundaries were unclear based on the provisions in the November 30, 2010 final rule.

First, we are proposing to strike the term ''at elevated pressure'' because it was not clear what ''elevated pressure'' meant. For example, elevated with respect to what baseline? Based on questions received on the definition for transmission compressor stations, we have proposed to clearly define transmission pipelines using a widely accepted designation for what is a transmission pipeline, avoiding the need to retain the language of ''elevated pressure.'' We are proposing to define in 40 CFR 98.238 that a *transmission pipeline* means a Federal Energy Regulatory Commission (FERC) rate-regulated interstate pipeline, a state rate-regulated intrastate pipeline, or a pipeline that falls under the ''Hinshaw Exemption'' as referenced in the Natural Gas Act.

Next, we are proposing to clarify the end points between which a natural gas transmission compression facility would move natural gas. Specifically, we are proposing to explicitly state that natural gas transmission compression facilities not only move natural gas from production fields or gas processing plants, but also move natural gas coming from other transmission compressors. In addition, we are proposing to explicitly state that natural gas transmission compression facilities may move natural gas into not only distribution pipelines, but also into liquefied natural gas storage or into underground storage.

We are also proposing to strike the term ''natural gas dehydration'' from the industry segment definition because this term does not represent a unique characteristic to facilities with natural gas transmission compression. We believe that deleting this term from the definition of the natural gas transmission compression industry segment, will result in this industry segment definition being more representative and accurate. Finally, as described above under onshore natural gas processing, we are proposing to strike the reference to ''gathering lines and boosting stations'' and ''facility.''

Natural Gas Distribution. EPA is proposing several amendments to the natural gas distribution industry segment definition to further clarify its intent. First, we are proposing in 40 CFR 98.230(a)(8) to eliminate the term ''city gate station'' and add the term ''meter-regulating station.'' The term ''city gate,'' was used in the 2010 final rule because it was believed to be widely used throughout the natural gas distribution industry. However, since publication, we have learned that the term can have several meanings and the interpretation of what is a ''city gate'' station may vary among potential reporters. By letter dated March 2, 2011 from the American Gas Association, it was stated that ''[t]he term 'city gate' is widely used in the industry, but unfortunately it means different things to different companies. It can mean the place where an LDC takes custody of natural gas from the upstream supplier (either directly from a producer or from an interstate pipeline company). The term 'city gate' is also used by some to refer to the place where natural gas is conveyed into a lower pressure distribution system for a town or city—either directly from the upstream supplier (producer or interstate pipeline) or from the LDC's own intrastate high pressure transmission pipelines. Some companies do not use the term 'city gate' to refer to the situation where natural gas goes from the company's own transmission pipes to one of its distribution systems. Instead, these companies may use other terms such as 'district regulator' or 'metering and regulating stations,' or 'M&R' equipment, and these terms also can have varying meanings.''

Further, subpart A provides a definition for ''city gate,'' which was intended to apply to subpart NN and is based on financial custody transfer. Whereas the connotation of the term city gate as defined in subpart A works sufficiently for subpart NN, it has created confusion for subpart W and does not clearly identify the types of facilities EPA intended to cover. The amendments that EPA is proposing are designed to more clearly portray EPA's intent using language readily understandable to industry.

First, we are proposing to strike the parenthetical term ''(not interstate transmission pipelines or intrastate transmission pipelines).'' The parenthetical was deemed unnecessary because EPA is proposing to add a definition for ''distribution pipeline'' in 40 CFR 98.238 that clarifies that ''distribution pipelines'' are only those designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA). Next, we are proposing to replace the term ''city gate'' with ''meter-regulating'' station. Because of the wide range of views in industry on the meaning of the term ''city gate'' EPA is proposing to remove the term ''city gate'' from subpart W and replace it with a term that reflects the types of activities occurring at the stations of interest. Specifically, we are proposing to add a definition for the term ''meter-regulating station'' in 40 CFR 98.238 to mean, ''An above ground station that meters the flow rate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.'' With this change, EPA intends to clarify a key concept in the natural gas distribution segment definition, but does not intend to change who is actually covered by the rule's requirements.

EPA is proposing to strike the terms ''excluding customer meters'' and ''physically deliver natural gas to end users'' because the proposed definition for ''meter-regulator'' stations already addresses this exclusion.

Finally, we are proposing to clarify in the industry segment definition that we are only seeking for LDCs that are within a single state, consistent with the definition for LDCs in subpart NN.

Greenhouse Gases to Report. We are proposing several amendments to the subpart W provisions on the greenhouse gases that must be reported.

We are proposing to amend 40 CFR 98.232(c) to clarify that the equipment listed in 98.232(c)(1) thru (22) are for equipment on a single well-pad or associated with a single well-pad in order to make the language consistent with the proposed changes to the onshore production industry segment definition in 40 CFR 98.230(a)(2) described above.

We are proposing to amend 40 CFR 98.232(i) by replacing the term ''custody transfer city gate station'' with the term ''transmission-distribution transfer station'' and replacing the term ''non-custody transfer station'' with the term ''metering-regulating station.'' EPA is proposing this amendment to clarify that the sources covered be consistent with the proposed terms for the natural gas distribution industry segment in 40 CFR 98.230(a)(8). We are also proposing to amend the source types by removing the text ''Customer meters are excluded.'' The exclusion is already covered in both the industry segment definition and in the definition of ''metering-regulating station'' provided in 40 CFR 98.238 and does not provide added clarity in this context. Next, we are proposing to strike 40 CFR 98.232(j) in order to address concerns raised that the inclusion of this provision resulted in confusion amongst reporters as they were unsure how this provision aligned with the flare emissions that are captured under the applicable emissions source calculations throughout 40 CFR 98.233. In addition to the proposal to strike 40 CFR 98.232(j), we are proposing to revise the introductory sentences to 40 CFR 98.232(e), (f), (g), (h), and (i) to clarify that N_2O emissions, which are the primary GHG emission from flaring, are also required to be reported under these industry segments. This proposed amendment also clarifies that flare emissions must only be calculated where ''flare stacks'' are either specifically identified in a specific industry segment (*e.g.,* onshore natural gas processing) or where an emissions source that is covered in an industry segment is routed to a flare (*e.g.,* centrifugal compressors under onshore natural gas transmission).

Finally, we are proposing to further clarify in 40 CFR 98.232(k) that the onshore production and natural gas distribution industry segments are to report their combustion emissions under subpart W, while the remaining industry segments are to report their combustion emissions under subpart C of part 98.

Calculating Greenhouse Gas Emissions. We are proposing several clarifications, corrections, and amendments throughout 40 CFR 98.233.

Natural Gas Pneumatic Device Venting. EPA is proposing to revise Equation W–1 in 40 CFR 98.233(a) by adding 40 CFR 98.233(a)(3) that allows the type of pneumatic devices to be determined using engineering estimation based on best available information. The proposed amendment for pneumatic devices was in response to questions received about how to determine whether a pneumatic device is high bleed or low bleed and the unanticipated burden for industry if they would have to measure the bleed rate of all pneumatic devices in order to determine how to characterize each pneumatic device.

EPA is also proposing to amend Equation W–1, to include a parameter ''T'' that estimates the total number of hours the devices were operational. Previously, this equation assumed that all natural gas pneumatic devices were operational all year, which would overestimate the emissions where the pneumatic devices operate less than a full year. Overall, we are proposing these amendments to Equation W–1 to more accurately reflect operating conditions for natural gas pneumatic device venting. Furthermore, EPA is clarifying in the definition for ''GHG_i'' that compositions in 40 CFR 98.233(u) may be used for the onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage industry segments.

In addition, with respect to the pneumatic device venting category, we are proposing in 40 CFR 98.236(c)(1)(iv) to clarify that emissions should be reported collectively for all high bleed pneumatic devices, then separately for all intermittent bleed pneumatic devices, and separately for all low bleed pneumatic devices. The 2010 final rule stated merely ''report emissions collectively.'' The proposed amendment is consistent with how data are collected and emissions calculated.

Natural Gas Driven Pneumatic Pump Venting. We are proposing to amend Equation W–2 in 40 CFR 98.233(c), which is used for calculating GHG emissions from natural gas pneumatic pump venting, to include a parameter ''T'' that estimates the total amount of hours the pumps were operational. Previously, this equation assumed that all natural gas pneumatic pumps were operational all year, which would overestimate the emissions where the pneumatic devices operate less than a full year. We are proposing this amendment to Equation W–2 to more accurately reflect operating conditions for natural gas pneumatic pump venting.

Acid Gas Removal Vents. We are proposing to amend the calculation for estimating CO_2 emissions from acid gas removal vents in Equation W–4 in 40 CFR 98.233(d). EPA notes that the equation in the 2010 final rule is an approximation and works well when the amount of CO_2 in gas is relatively low, such as 1 percent. However, the error rate in the estimate increases significantly as the amount of CO_2 in gas increases. Therefore, EPA is proposing a new equation, which uses the exact same input parameters and thus will not result in any additional burden to reporters, but will improve the quality of the information submitted to EPA.

We are also proposing to amend 40 CFR 98.233(d)(1) to specify that the use of CEMS is required if a CO_2 concentration monitor and volumetric flow rate monitor are installed. This amendment was made to clarify what conditions must be met to satisfy the subpart C: Stationary Combustion Tier 4 calculation requirement for Acid Gas Removal vents and to make the requirements consistent in subpart W where use of CEMS is required.

In 40 CFR 98.236(c)(3) we are proposing to clarify that reporting of CO_2 content should reflect the annual average of the measurements undertaken in 40 CFR 98.233(d). The 2010 final rule was not clear on whether or not to aggregate the measurements, and if so, how.

Dehydrator Vents. EPA is proposing several amendments to the provisions in 40 CFR 98.233(e) for calculating GHGs from dehydrator vents. First, we are proposing to clarify that gases other than natural gas, such as nitrogen, flash gas from the flash tanks, or dry gas from the absorber, that are used as stripping gases satisfy the requirements stated in 40 CFR 98.233(e)(1) introductory language. The final rule explicitly stated that natural gas was the gas considered to be the stripping gas. We are proposing this amendment to more accurately reflect operating conditions for glycol dehydrators in which gases other than natural gas are used as stripping gases.

We are also proposing to amend 40 CFR 98.233(e)(6) to clarify that GHG mass emissions from glycol dehydrators are to be calculated from volumetric GHG emissions using calculations in 40 CFR 98.233(v). In addition, we are proposing to clarify that only for dehydrators that use desiccant should GHG volumetric and mass emissions be calculated using paragraphs 40 CFR 98.233(u) and 98.233(v). We are proposing this amendment to account for calculation methodology 1 and 2, 40 CFR 98.233(e)(1)–(e)(3), that calculates total GHGi volumetric emissions in standard cubic feet and will only need conversion to GHG mass emissions using 40 CFR 98.233(v).

With respect to the data reporting requirements, we are proposing to clarify the requirement to report vented and flared emissions individually. In the 2010 final rule, EPA intended that vented emissions be reported as one value, and flared emissions as a separate value. However, because these were entered in the same sub-paragraph, 40 CFR 98.236(c)(4)(i)(J), there was some ambiguity as to the aggregation for reporting. Therefore, EPA is proposing to create separate reporting requirements for vented and flared emissions. A similar amendment is proposed for 40 CFR 98.236(c)(4)(ii)(D).

Also for dehydrators, EPA is proposing to clarify that in specifying whether any vent gas controls have been used, the owners or operators should report which vent gas controls were used.

Well Venting for Liquids Unloadings. First, we are proposing to revise 40 CFR 98.233(f) methodology 1, methodology 2, and methodology 3 such that sampling would be done in a sub-basin category as opposed to the field level as described earlier in Section II.C. of this preamble (Sub-basin Category for Onshore Petroleum and Natural Gas Production).

In the technical corrections rule, EPA proposed several technical corrections to the provisions in 40 CFR 98.233(f) including corrections to Equation W–8, W–9, and their respective definitions. In today's action, we are proposing additional revisions to Equations W–8 and W–9 and their respective definitions. Because both proposed actions affect the same paragraph of the rule, for clarity the part 98 amendatory language at the end of this preamble contain the full set of revisions from both proposed actions. The changes proposed today are explained below in this preamble.

First we are proposing to revise Equation W–8 by correcting the definition for parameter $E_{a,n}$ to be $E_{s,n}$ to accurately reflect that the calculated emissions should be in standard conditions and not actual conditions. The proposed revision from actual conditions to standard conditions was made to be more uniform in approach to calculate emissions. The parameters in Equation W–8 have been made applicable to each venting instance, q, and for each well, p, in a pressure grouping and sub-basin category. These changes are notational amendments that correct the summation operation. Next, we are proposing to amend the definition for ''SFR'' which is the average sales flowrate to state that the average sales flow rate of gas is to be obtained at standard conditions, and also that Equation W–33 may be used to convert the sales flow rate from actual to standard conditions. In addition, the definition for parameter WD_{wp} has been clarified to mean the distance between the lowest packer to the bottom of the well. We are also proposing to remove 40 CFR 98.233(f)(2)(i) to remove redundancy with 40 CFR 98.233(f)(4). As stated previously, we are proposing to amend Equation W–9 in the same manner as Equation W–8: By revising the definition for ''$E_{a,n}$'' to accurately state that the definition should result in standard conditions, thus ''$E_{s,n}$'', and by revising the definition for SFR to state that the average sales flow rate is to be calculated at standard conditions using Equation W–33; and the parameters, where applicable, have been made applicable to each venting event, q for each well, p, in a pressure grouping and sub-basin category to correct the summation. Finally, we are proposing to amend Equation W–8 and W–9 to account for a change in aggregation from field level to sub-basin category for reporting.

For Calculation Method 1, where a representative measurement is taken from one well unloading and then applied to all other wells of a similar type, EPA is defining the categorization of ''similar types'' by five pressure ranges and three tubing diameters. The pressure ranges were optimized using HPDI well counts in 5 psig pressure increments from zero gauge pressure to 200 psig. The fifth ''unbounded'' pressure range is ''greater than 200 psig,'' which EPA believes will have very few well liquids unloading venting to the atmosphere. The three tubing diameter ranges, equal or less than 1 inch, greater than 1 inch and equal or less than 2 inch, and greater than 2 inch, were derived from gas well tubing suppliers' specifications. The relevancy of these pressure ranges and tubing diameter ranges is that liquids unloading venting is dependent on both the shut-in pressure of the reservoir (shut-in by liquids accumulation) and velocity of gas pushing liquids up the tubing, which is a function of tubing diameter.

Finally, in the data reporting requirements in 40 CFR 98.236(c)(5), we are proposing to make a harmonizing change, consistent with the amendments described above in (Sub-basin Category for Onshore Petroleum and Natural Gas Production), that reporting should be for each well tubing diameter grouping and pressure grouping within each sub-basin category.

Gas Well Venting During Completions and Workovers From Hydraulic Fracturing. We are proposing several amendments to 40 CFR 98.233(g) to account for the proposed change in aggregation from field level to sub-basin category for taking measurements. For example, we are replacing the term ''field'' with ''sub-basin and well type combination'' in the definitions and clarifying that the GHG emissions are determined for each sub-basin and well type combination. For further discussion on the proposed changes from field level calculations and reporting to sub-basin category, please refer to Section II.C of this preamble (Sub-basin Category for Onshore Petroleum and Natural Gas Production).

We are also proposing to revise equation W–10 by including a provision to account for the time period in which we believe normal production of a well would be established. In this action, we are revising equation W–10 by defining a parameter, FRM, which would represent the ratio of emissions (FR_p) to the average 30 day production from the well immediately following hydraulic fracturing (PR_P). The emissions, FR_p, which in the final rule as the average flow rate in cubic feet per hour converted to standard conditions, are calculated using W–11A and W–11B. FRM is calculated using the newly assigned Equation W–12. We believe that this proposed revision will more accurately represent the production flow from a well immediately following a well or completion using hydraulic fracturing and will more accurately represent when a completion or workover ends and when normal production begins. Finally, in Equation W–10, EPA is proposing to add the parameter W, which is the number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination, and, where appropriate, made the parameters applicable to each well p. This amendment corrects the summation operator to make it mathematically accurate.

EPA also added Equation W–11C, which allows reporters to determine whether the well flow rate of gas during venting to the atmosphere or a flare (*i.e.,* FRW_P, is sonic or sub-sonic flow. Thus, reporters can determine whether to use Equation W–11A, which is for sub-sonic flow, or Equation W–11B, which is for sonic flow.

We are also proposing several minor edits to 40 CFR 98.233(g)(3) and 40 CFR 98.233(g)(5) to clarify that all requirements in 40 CFR 98.233(g) apply to gas well venting during completions and workovers from hydraulic fracturing, consistent with the emission source name of ''Gas well venting during completions and workovers from hydraulic fracturing''.

In 40 CFR 98.233(g)(3) we are also proposing to delete the reference to how to calculate the volume of recovered completion or workover gas. The first sentence in that paragraph is already clear that company records may be used, therefore the second sentence does not provide any additional information and is duplicative.

We are proposing several harmonizing changes to the data reporting requirements for this emissions source. We are proposing to indicate that reporting is required for each ''sub-basin category'' and well type (horizontal or vertical). We are also proposing to clarify that reporting of reduced emissions completions for both well completions and workovers is required. Although this information is required to be collected for both well completions and well workovers, EPA inadvertently omitted the reporting requirement for reduced emissions completions for well workovers.

Also in 40 CFR 98.236, we are proposing to clarify that reporters are only required to count the number of workovers that flare or vent gas to the atmosphere. There is no reporting requirement for workovers that do not flare or vent gas.

Gas Well Venting During Completions and Workovers Without Hydraulic Fracturing. In this section we are proposing to strike the term ''well workovers not involving hydraulic fracturing'' from the introductory text in paragraph (h) because it was repetitive.

Second we are proposing to replace the term ''field'' used in the definition for the parameter ''N_{wo}'' and ''f'' for the same reasons stated in Section II.C. of this preamble (Sub-basin Category for Onshore Petroleum and Natural Gas Production).

Finally, EPA is proposing to amend the summation operator in Equation W–13 to make it mathematically accurate. This includes making specific parameters in Equation W–13 applicable to each well completion, p.

Blowdown Vent Stacks. In a previous action we proposed amendments to the introductory sentences to 40 CFR 98.233(i). In this action, based on additional questions received during implementation of subpart W, we are proposing to further clarify the types of blowdowns that EPA intended to cover. First, we are proposing to delete ''to atmosphere'' because not every blowdown will result in the blowdown chamber being brought to atmospheric pressure. Operators often release only part of the gas in the blowdown chamber and maintain it at low pressure. It was always EPA's intent to cover these types of ''blowdowns'' and thus we are proposing to delete ''to atmosphere''. Further we are clarifying that we only intend to cover the types of blowdowns typically tracked by operators for planned maintenance or emergency shutdowns. EPA had earlier proposed to exclude emergency shutdowns in a previous action. However, EPA has since been informed that operators track emergency shutdowns already. Therefore, EPA is proposing to require emergency shutdowns to be reported. In addition, we did not intend to capture blowdowns that are not typically tracked by operators, such as pressure release valve releases designed to keep equipment under safe operating mode.

EPA has also considered other factors that could impact emissions from blowdowns, for example compressibility. We have considered accounting for gas compressibility but have not proposed this because we believe that the effort in adjusting for a compressibility factor outweighs the benefits in terms of increased accuracy. EPA seeks comments on why such an allowance should be provided and how to standardize this option so that those who choose to use it all do so in the same way.

Also in this action, we are proposing to revise the numbering of Equation W–14b and include an additional Equation, W–14b that will take into account that a chamber may not be blown down to atmospheric pressure, and will allow facilities the option of tracking blowdowns by each occurrence by blowdown volume. It has come to EPA's attention that some facilities may log blowdowns at a facility by individual blowdown occurrence. To enable facilities to retain their current tracking system, we are proposing to add an option for calculating blowdown emissions by equipment type. This option for tracking blowdowns would not impact data quality. Harmonizing changes in 40 CFR 98.236(c)(7) are being proposed to account for these amendments.

Lastly, we are proposing to include a default composition for the natural gas transmission industry segment, and for the LNG storage and underground storage segments. EPA received feedback from industry that a default composition of 95 percent methane and 1 percent CO_2 was a representative breakdown of the gas composition at these types of facilities while limiting burden and should be acceptable. EPA agrees that a default composition of 95 percent methane and 1 percent CO_2 is appropriate because the composition of natural gas is monitored by transmission compression companies and regulated by FERC.

Onshore Production Storage Tanks. EPA is proposing to replace the term ''field'' in 40 CFR 98.233(j)(1)(vii)(B), 40 CFR 98.233(j)(1)(vii)(C), and 40 CFR 98.233(j)(3)(i) with ''sub-basin category'' consistent with the proposed amendments described in Section II.C, (Sub-basin Category for Onshore Petroleum and Natural Gas Production), of this preamble. We are also proposing to clarify this level of reporting in the data reporting requirements in 40 CFR 98.236(c)(8).

Also in the data reporting requirements, we are proposing to clarify the reporting requirement in 40 CFR 98.236(c)(8)(i), 98.236(c)(8)(ii) and 98.236(c)(8)(iii) that reporters must report vented, flared, and recovered emissions individually for Calculation Methodology 1 and 2. This is consistent with the calculation requirements.

Transmission Storage Tanks. We are proposing to revise 40 CFR 98.233(k) to include an additional provision such that reporters would now have the option of directly measuring the transmission storage tanks while bypassing an initial screening with the optical gas imaging instrument. EPA received feedback from industry that some owners and operators would prefer to simply measure the tank annually without having to be required to screen the tank vapors with a camera first. We agree that allowing facilities to directly measure the emissions, without first requiring leak detection, does not compromise data quality, but could enable facilities to meet the requirements of the rule with lower burden. Therefore, in this action, EPA is proposing to allow operators to either screen their tanks first by using the optical gas imaging instrument for 5 continuous minutes and if a leak is detected, measure the leak according to the provisions in 40 CFR 98.234 consistent with the 2010 final rule, or measure the tank vent vapors for 5 minutes using either a flow meter, calibrated bag, or high volume sampler according to the provisions outlined in 40 CFR 98.234.

Finally, with respect to the data reporting requirements in 40 CFR 98.236(c)(9), as described further above, we are proposing to clarify the separate reporting requirements for vented and flared emissions.

Well Testing Venting and Flaring. EPA is proposing In amendments to the data reporting requirements in 40 CFR 98.236(c)(10). Specifically, we are proposing to add a reporting requirement for the emissions of the flaring gas collectively. This is consistent with other proposed clarifications to report flared emissions separately.

EPA is considering, and has not proposed, using the production rate to estimate volume of emission from gas wells that produce dry gas. EPA is soliciting comments on this suggested provision for gas wells.

EPA has received several requests to exclude the well testing venting and flaring emissions source from the rule. Industry has informed EPA that this source has very little, if any, emissions because the well testing is almost exclusively performed in a closed system using a ''test separator,'' which industry has stated would result in zero emissions.

EPA has reviewed this request and in general, EPA continues to believe that well testing venting and flaring is a relevant source in the onshore petroleum and natural gas production industry segment. In addition, EPA has determined that during well testing, some states allow companies to flare sour gas for a maximum of 72 or 144 hours. EPA has concluded that this approach would result in emissions from this source that should be reported under this rule. If, however, for some reason reporters do not have any emissions from this source (for *e.g.,* states do not allow venting or flaring from well testing), they would report zero emissions.

Thus, EPA is retaining well testing venting and flaring in the rule. However, EPA is seeking comment on how to reduce or eliminate burden in cases where companies verify that zero emissions are associated with this potential source, such as when a closed loop system is employed.

Associated Gas Venting and Flaring. EPA is proposing to revise 40 CFR 98.233(m) to replace the term ''field'' with the term ''sub-basin category'' for the same reasons outlined in Section II.C. (Sub-basin Category for Onshore Petroleum and Natural Gas Production) of this preamble.

Flare Stack Emissions. We are proposing two amendments in 40 CFR 98.233(n)(2) to clarify how to determine gas compositions for hydrocarbon streams going to flare. First, we are proposing to amend 40 CFR 98.233(n)(2)(ii) to clarify that reporters must use the GHG mole percent in feed natural gas for all streams for onshore natural gas processing plants that solely fractionate a liquid stream. EPA is proposing this amendment to address lack of clarity in the final provisions which did not explicitly state how natural gas processing plants which only fractionate liquid streams would determine their gas compositions. We are also proposing to clarify in 40 CFR 98.233(n)(2)(iii) that methane, in addition to ethane, propane, butane, pentane-plus and mixed light hydrocarbons, should be accounted for when the stream going to the flare is a hydrocarbon product stream. This proposed technical correction, to add methane, ensures that paragraph 40 CFR 98.233(n)(2)(iii) is consistent with the equation.

In addition, we are proposing to clarify the summation operator in W–21 to make it mathematically correct. We are also clarifying that source types in 40 CFR 98.233 that send emissions to a flare must determine volumetric flow rate, parameter ''Va'', in Equation W–19 through W–20, at actual conditions.

We are also proposing to clarify that the volume of gas sent to the flare should be calculated in actual conditions. This is consistent with other proposed changes throughout this revision that clarify the use of actual versus standard conditions.

In addition, we are proposing to allow facilities the option to use a continuous emissions monitoring system (CEMS) to estimate GHG emissions from flares. EPA received questions as to why CEMS were allowed for use for AGR vents, for example, but not for flares. We did not intend to unnecessarily limit the measurement options for flares, and therefore are proposing to add the option to use CEMS.

The proposed text clarifies that the use of CEMS is required if a CO_2 concentration monitor and volumetric flow rate monitor are installed and that optionally a user may install a CO_2 concentration monitor and volumetric flow rate monitor to be eligible to use the Tier 4 methodology. When CEMS are used to calculate emissions for flare stacks the use of equations W–19 to W–21 would no longer apply. With the relatively high quantity of unburned methane in the emissions from flares, EPA has identified that it is not appropriate to use the CH_4 calculation methodology in subpart C as most flared gases will not be fuels listed in Table C–1 of subpart C. EPA is seeking comment on what form an equation should take that would calculate CH_4 and N_2O for flares that are monitored by CEMS. One option is to calculate the CH_4 by multiplying the concentration of CO_2 measured by the CEMS by the fraction of CH_4 that was not combusted as determined by flare efficiency.

In the data reporting requirements in 40 CFR 98.236(c)(12) we are proposing to add reporting requirements consistent with the calculation requirements in Equations W–19 through W–21. Specifically, we are proposing to add reporting of uncombusted CH_4, combusted and uncombusted CO_2 and combustion-related N_2O emissions. The proposed amendments ensure consistency across the calculation, monitoring and reporting requirements.

Centrifugal Compressor Venting. Consistent with other clarifications throughout this proposed rule, we are proposing to clarify in the definition for the term MTm in Equation W–24 that flow measurements should be determined in standard cubic feet per hour.

Leak Detection and Leaker Emission Factors.

We are proposing to revise 40 CFR 98.233(q)(8) to remove the term ''city gate stations at custody transfer'' and replace with ''transmission-distribution transfer stations'' for the reasons described earlier in Section II.C of this preamble. We are also proposing to remove the term ''meters and regulators'' and replace with above ground ''metering-regulating stations''. The term ''meter-regulating'' is a term that we are proposing to define in this action, as described earlier in Section II.C of this preamble.

The revisions to terminology for natural gas distribution facilities have been proposed to clearly identify who is covered under the distribution segment of subpart W, and the sources for which leak detection and measurement are required and those sources for which an emission factor can be used. Based on feedback received from industry, there may be concerns that the emission factors developed at the transmission-distribution transfer stations are not representative of emissions at other above ground metering-regulating stations. Although we are not proposing changes to the approach for applying emission factors to above ground metering-regulating stations in this action, we are seeking comment on alternative approaches, or data that may be used, for determining emissions factors for above ground metering-regulating stations. Based on comments received, EPA may consider future amendments to the rule.

In a separate action, (76 FR 37300) EPA is proposing to expand the final BAMM provisions to cover all facilities subject to subpart W, and allow reporters the option to use best available monitoring methods (BAMM) for all of 2011 without being required to submit a request for approval to the Administrator. For natural gas distribution facilities at transmission-distribution transfer stations, this would allow facilities to estimate the number of equipment leaks and the equipment sources themselves using BAMM as provided in the rule, along with the total time the component was found leaking and operational, as outlined in Equation W–30. This emission factor could then be used for other above ground metering-regulating stations within the facility boundary.

EPA is proposing to clarify the summation operator in W–30 to make it mathematically correct. This clarification includes amending x to be the total number of each equipment leak source and adding T_p, which is the total time the component p was found leaking and operational. We are proposing to revise the parameter GHG_i. For industry segments listed in 98.230 (a)(4) and (a)(5), GHG_i has been revised to 0.974 for CH_4 and $1.0 \times 10–2$ for CO_2. For industry segments listed in (a)(6) and (a)(7), GHG_i equals 1 for CH_4 and 0 for CO_2. For industry segments listed in (a)(8), GHG_i equals 1 for CH_4 and $1.1 \times 10–2$ CO_2 (See Technical Support Document Memo (TSD) in Docket ID EPA–HQ–OAR–2011–0512 for further details).

Next we are proposing two amendments in 40 CFR 98.236(c)(15). We are proposing to amend the reporting requirements in 40 CFR 98.236(c)(15)(i)(C) to clarify that owners or operators must report CH_4 emissions collectively by equipment type and CO_2 emissions collectively by equipment type. The calculation methodologies in 40 CFR 98.233(q), as finalized in the rule, require reporters to calculate CH_4 emissions and CO_2 emissions separately per source with equipment leaks. We are proposing this amendment to clarify that applicable reporters must report the CH_4 emissions collectively by equipment type and CO_2 emissions collectively by equipment type. We are also proposing to correct the reporting requirement in 40 CFR 98.236(c)(15)(ii)(A) to not include onshore natural gas processing. This source category is not required to use population emission factors. This amendment is associated with the amendment to Equation W–31 in 40 CFR 98.233(r) discussed in Calculating Greenhouse Gas Emissions.

Population Count and Emission Factors. We are proposing several amendments in 40 CFR 98.233(r). First we are proposing to amend the population emission factor definition in equation W–31 by replacing the term ''non-custody transfer city-gate'' with above grade ''metering-regulating station'' for the reason stated above in this preamble. We are also clarifying that the count in equation W–31 applies to the number of ''meter/regulator runs'' at all ''metering-regulating stations'' combined.

We are also proposing to amend the term ''count'' in W–31 as follows to elaborate and clarify how each industry segment should count the total number of equipment/components. In that same equation, we are also proposing to revise the definition for GHG_i by referring to 40 CFR 98.233(u) and deleting the composition specified for each industry segment.

Next, EPA is proposing to amend 40 CFR 98.233(r)(2)(i) to explicitly state how meters and piping are to be counted. Table 1–B of the 2010 final rule was developed using activity data from the 1996 EPA/Gas Research Institute Study (1996 EPA/GRI Study), Methane Emissions from the U.S. Natural Gas Industry. For all major equipment that are not specifically listed, the 1996 EPA/GRI Study categorized all components at a well-pad under the meters/piping category. Therefore, owners or operators should use one count of meters/piping per well-pad.

Further, consistent with proposed amendments described above, EPA is proposing to amend 40 CFR 98.233(r)(6)(ii) by referring to ''metering-regulating stations'' in place of ''city gate'' and to clarify that the emission factor for meter/regulator runs at all metering-regulating stations in equation W–32 is based on leak detection performed at ''transmission-distribution transfer stations''. EPA is also amending 40 CFR 98.233(r)(6)(i) to clarify that below grade meters and regulators apply to below grade ''metering-regulation stations''.

Lastly, we are proposing revisions to equation W–32 that include revisions to the definitions for EF, $E_{s,i}$, and ''Count'' again to clarify the terminology change away from ''custody transfer'' to above ground ''metering-regulating'' stations. We are also proposing the inclusion of a conversion factor to convert to hourly emissions. Consequently, we are proposing to amend the conversion in Equation W–32 in 40 CFR 98.233(r) so that the equation yields an EF in cubic feet per meter per hour to be used in Equation W–31 for above ground metering-regulating stations. Finally, the summation operator has been removed in Equation W–32 because $E_{s,i}$ represents annual volumetric GHG_i emissions at all T–D transfer stations, making the summation operator redundant.

In addition to the proposed calculation amendments described above, we are also proposing to replace the term ''field'' with ''sub-basin category'' in the reporting for onshore production, consistent with the proposed change to sub-basin calculation and reporting.

Volumetric Emissions. We are proposing to amend 40 CFR 98.233(t) to clarify that reporters should use actual temperature and pressure and adjust to standard conditions. The phrase ''by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas'' was deleted because it is redundant.

GHG Volumetric Emissions. We are proposing to amend 40 CFR 98.233(u) to include 95 percent methane/1 percent CO_2 default gas composition for the natural gas transmissions industry segment, along with the LNG storage and underground storage industry segments. Again, as described above, EPA agrees that a default composition of 95 percent methane and 1 percent CO_2 is appropriate because the composition of natural gas is monitored consistently and regulated by FERC.

We are also proposing to strike the reference to the term ''field'' in 40 CFR 98.233(u) and replace with ''sub-basin category'' for the reasons outlined in Section II.C. of this preamble (*Sub-Basin Category Reporting for Onshore Petroleum and Natural Gas Production*).

We are also proposing to clarify that the GHG mole fraction that is determined without using a continuous gas analyzer may be determined using an annual average instead of the most recent gas composition based on available analysis in a sub-basin entity.

GHG Mass Emissions. We are proposing to clarify in the definitions to equation W–36 that the equation applies to N_2O emissions as well. N_2O emissions are calculated from stationary combustion and flares, and the proposed edit is necessary to convert the mass emissions of N_2O to carbon dioxide equivalents of gas. EOR injection pump blowdown. We are proposing to clarify in the equation that only CO_2 emissions are calculated. The variables $Mass_{c,i}$ has been changed to $Mass_c$, CO_2, and GHG_i has been changed to GHG_{CO2}.

Onshore Production and Distribution Combustion Emissions. In a previous action, EPA proposed several revisions to 40 CFR 98.233(z) including corrections to Equations W–39 and 40. In this action, we are proposing additional amendments to clarify when owners or operators of onshore production and distribution facilities must use the methods in 40 CFR subpart C to calculate combustion-related emissions and when they must use the methods in 40 CFR 98.233(z) to calculate combustion-related emissions. We are proposing to clarify that facilities using subpart C to calculate emissions are not limited to the use of tier 1, but rather may use any tier. Regardless of the tier used, the facility must follow the corresponding calculation, monitoring and reporting requirements of that tier.

We are also proposing to amend the requirements for units combusting field gas or process vent gas. The 2010 final rule required the use of a continuous flow meter, if present. Use of a continuous flow meter would have necessitated calibration requirements per 40 CFR 98.3(i). These calibration requirements were disproportionately burdensome for these relatively small disperse units, particularly given that facilities that currently do not have a flow meter in place could use company records. In this action, we are proposing to amend the requirements to allow the use of company records for this equipment.

Onshore Production and Distribution Equipment Threshold for Internal Combustion Equipment. In letters dating January 31, 2011 and March 5, 2011 from API and AGA, respectively, EPA received petitions to reconsider an exemption for internal combustion engines similar to that which was in the final subpart W rule (75 FR 74458, November 30, 2010) for external combustion engines. These requests from the onshore petroleum and natural gas production and natural gas distribution reporters were to provide respite for reporting of emissions from internal combustion equipment that are brought in temporarily for maintenance and construction. Some reporters have requested complete exemption such that combustion equipment that fall below a specific threshold would be exempt from reporting.

EPA considered, but decided not to propose an exemption for reporting for internal combustion engines. EPA decided not to propose amendments because data currently are not available to sufficiently characterize these upstream emissions. For example, the volume of fuel consumed, especially at wellhead natural gas compressors, is not being monitored and only limited data, voluntarily reported, are available through the Energy Information Administration.

Although EPA has decided not to propose a threshold due to lack of availability of a comprehensive data source from which to develop policy, we acknowledge that there is potentially small internal combustion equipment outside of compressors. In considering a potential equipment threshold for non-compressor internal combustion engines, EPA collected and reviewed data on the size ranges of small, portable internal combustion engines that may be brought to a wellhead for periodic maintenance and construction. Such equipment would include, for example, electric generators for arc welding, electric generators powering portable flood-lighting, and electrical generators or gasoline engines powering air compressors (for sand blasting or pneumatic tools). For lighting, the industrial generators were almost exclusively below 12 horsepower (hp), with the highest found being 13.9 hp. For welding machines, we assumed that they would use standard portable generators, since specific information on these types of machines was scarce. Most portable industrial generators are rated between 15–40 hp, with the largest one found being 67 hp. EPA determined that 130 horsepower (double the largest size found) would exclude virtually all small portable or stationary internal combustion engines, but is much smaller than the 5 mmBtu/hour exclusion for external combustion sources and equates to about 1 mmBtu/hour. EPA is seeking comments on whether a 1 mmBtu/hour equipment threshold for internal combustion engines that are not driven by natural gas is reasonable. We also seek comment on EPA's position that combustion-related emissions at compressors should not be excluded from reporting, regardless of size and where EPA can find reliable estimates of natural gas consumption.

EPA is proposing to clarify the summation operator in Equation W–39 to make it mathematically correct. In addition, EPA is proposing to clarify in Equation W–40 that N_2O mass emissions are calculated by changing the parameter N_2O to Masss, N_2O.

In specific, EPA is soliciting comments as to why emissions from specific internal combustion related equipment should not be reported including the size of the equipment that should be excluded along with supporting data.

Monitoring and QA/QC Requirements. We are proposing several amendments to the monitoring and QA/QC requirements in 40 CFR 98.234.

First, we are proposing to amend the language in 40 CFR 98.234(a)(1) by first removing and reserving the text in 40 CFR 98.234(a)(4) and combining it with 40 CFR 98.234(a)(1), thus resulting in one consolidated paragraph. We are also proposing to state explicitly that video recordings are not required under subpart W. As noted in the Response to Comments to the 2010 final rule,[5] EPA did not intend to require retention of a video recording of the leak detection using optical gas imaging instruments for reporting to EPA under subpart W of the greenhouse gas reporting rule. However, some of the references to the Alternate Work Practice suggested that EPA intended that facilities retain these records onsite.

Next, we are proposing to amend the language in 40 CFR 98.234(a)(2) to state that Method 21 compliant instruments may be used to monitor inaccessible emissions sources. This amendment increases flexibility in monitoring requirements and reduces the burden on the industry, without compromising data quality.

Further, based on questions raised by industry, we are proposing to amend 40 CFR 98.234(a)(5) by revising the acoustic leak detection device provisions to use a different model of acoustic detector, one that does not have a through-valve leakage correlation, thereby allowing leakage to be measured by other methods if a leak is found. However, EPA is proposing to clarify that not all types of acoustic detectors are allowed. In particular the ''gun'' type instrument that is aimed at the equipment from a distance to detect the acoustic signal of leakage is not an allowable instrument. This type cannot distinguish between external leakage to the atmosphere from internal, through-valve leakage, which is the objective for specifying this device. EPA is proposing to further specify that the ''stethoscope'' type acoustic detector that senses through valve leakage when put in contact with the valve body, but does not have the leakage estimating correlations, may be used.

We are also proposing editorial revisions in 40 CFR 98.234(c) for calibrated bagging to specify that those using the calibrated bag for sampling, must ensure that the emissions must be at a temperature below that which the bag manufacturer specifies for safe handling.

Data Reporting Requirements. We are proposing several amendments and clarifications throughout 40 CFR 98.236 in order to address questions received about how data should be reported. Many of the data reporting requirements were lacking clarity with respect to the level of reporting. Based on the questions received, as well as EPA's experience gained in developing the electronic GHG reporting tool (e-GGRT), which provided EPA a better understanding of the clarity necessary in the data reporting requirements, EPA is proposing the following changes.

In cases where technical amendments were already proposed for individual emissions sources above, EPA has described the corresponding proposed amendments to the reporting requirements along with the technical amendments. This section outlines any remaining proposed amendments to the data reporting requirements not already described above.

First we are proposing to clarify the data reporting requirements for offshore petroleum and natural gas production facilities in 40 CFR 98.236(b). Specifically, the 2010 final rule was not clear in terms of which gases were required to be reported and the data elements for reporting. Consistent with the calculation requirements, we are proposing to clarify that facilities containing the offshore petroleum and natural gas production segment would be required to report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons CO_2e per year at standard conditions) individually for all the emissions source types listed in the most recent BOEMRE study.

Next, in the introductory paragraph for 40 CFR 98.236(c) we are proposing to clarify that vented emissions should be reported separately from flared emissions. We have specified which source types require separate calculation of flared emissions, but EPA is taking comment on whether any source types that have process gas routed to flares were excluded from having specific reporting requirements established for flares.

We are proposing to make changes to the data reporting requirements for local distribution companies, consistent with the proposed amendments to 40 CFR 98.230(a)(8). Specifically, we are proposing to replace ''custody transfer'' with ''transmission-distribution transfer'' station and replace ''non-custody transfer'' with ''above ground metering-regulating station.'' In addition, we are proposing to require the reporting of counts and emissions of both above grade and below grade stations for each of metering-regulating stations and ''transmission-distribution transfer stations.''

Finally, EPA seeks some basic information on average API gravity of the hydrocarbon liquids produced, gas to oil ratio, and low pressure separator pressure per sub-basin entity. It is EPA's understanding that his information is already known to reporters. EPA will use these facility sub-basin

[5] *Response to Comments Document:* Subpart W—Petroleum and Natural Gas Systems, part 2, page 28. *Comment Number:* EPA–HQ–OAR–2009–0923–1039–23.

characteristics to characterize other emissions sources across different sub-basins.''

Records that must be retained. EPA is proposing to add the following recordkeeping requirement: ''The records required under § 98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.'' While EPA believes this requirement is already included in 40 CFR 98.3(g)(2)(i) where the records for ''The GHG emissions calculations and methods used'' requirement is made, EPA believes that adding this statement to the recordkeeping requirements in subpart W will provide facilities with further clarity on the records they are required to keep. This clarification is intended to make clear that stating company records, engineering estimation, or best available information were used is not enough to satisfy the requirement in 40 CFR 98.3(g)(2)(i). This requirement is intended to parallel a similar requirement for subpart C specified in 40 CFR 98.34(f) and referenced in 40 CFR 98.37.

Definitions. We are proposing to amend, and in some cases, add definitions to 40 CFR 98.238 to further clarify rule requirements.

Associated With a Single Well-Pad. We are proposing to add a definition for ''associated with a single well-pad'' to clearly demarcate the boundary of onshore production. EPA proposes that the association be defined by the hydrocarbon stream from a single well-pad. The association with a single well-pad ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. In addition, we are stating that this definition does not include storage and condensate tanks that are located downstream of the point of combination. For gas contained in crude oil or condensate flowing under pressure off a single well-pad to a gas-liquid separator or tank, or comingled with flow from other well-pads, 40 CFR 98.233(j) requires reporting of the gas content that may be released from the oil or condensate in an atmospheric pressure fixed roof storage tank. We have determined that the conditions of the pressurized oil or condensate (*i.e.,* gravity, pressure, temperature, flow rate) are commonly known by the well owner/operator, and the amount of gas that may be released from the oil or condensate with a pressure reduction can be determined most appropriately by the well owner/operator.

Distribution Pipeline. EPA is proposing to include a definition for distribution pipelines to add clarity on its intent on coverage for the natural gas distribution industry segment. We are proposing to use a widely accepted definition for distribution pipelines, specifically, those designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA).

Facility With Respect to Natural Gas Distribution. EPA is proposing to revise the definition for natural gas distribution by replacing the term ''metering stations, and regulating;''with the term ''metering-regulating.'' EPA is proposing to include a definition for the term above ground ''metering-regulating station'' to clarify where leak detection and monitoring is required in the 2010 final rule.

Farm Taps. EPA is proposing to revise the definition for farm taps in 40 CFR 98.238 by striking the unnecessary phrase ''The gas may or may not be metered, but always does not pass through a city gate station.''

Flare. We are proposing to add a definition of flare specific for subpart W to address questions received during implementation about what constitutes a flare. The proposed definition clarifies that a flare may be either at ground level or elevated and uses an open or enclosed flame to combust waste gases without energy recovery. This definition for subpart W is intended to be inclusive of devices that combust waste gases without energy recovery. This broad, all-inclusive definition for subpart W is necessitated by the wide variety of waste gas combustion devices that are or may be used in the different segments of subpart W, all for the same purpose and having the same effect of combustion emissions of hydrocarbon gases.

Forced Extraction of Natural Gas Liquids. We are proposing to add a definition for forced extraction to restrict it to specific processes. EPA determined that it was necessary to develop this more precise definition because many industry questions pointed to the confusion between processing plants, gas gathering stations and wellheads, where similar equipment and processes are conducted as at some, but not all, processing plants that EPA determined should be subject to this rule. Those similar processes. These processes in and of themselves do not make a facility a ''processing plant.'' Furthermore, the Oil & Gas Journal annual survey of gas processing plants is primarily focused on those that fractionate, leaving out known, large gas plants that separate NGLs or condition gas, but do not fractionate, and are clearly not gathering booster stations. The key principle that EPA is attempting to clarify through this definition is the separation of heavier hydrocarbons in the vapor phase of natural gas delivered to a plant, excluding the simple gravity separation of liquids entrained in the gas. This principle is ''forced extraction,'' as defined here.

Horizontal Well. With the change from field level reporting to sub-basin category, EPA is proposing to add a distinction for calculating emissions from horizontal wells and vertical wells. We are proposing to define horizontal well to mean a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Sub-Basin Category. With the change from field level reporting to sub-basin category, EPA is proposing to add a definition for sub-basin category to mean a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following four formation types: Conventional with > 0.1 millidarcy permeability, and unconventional with ≤ 0.1 millidarcy permeability shale, coal seam, and other tight reservoir rock, all of which are unconventional with ≤ 0.1 millidarcy permeability. Unconventional wells producing from formations categorized in two or more types are considered shale for a combination of ''shale and coal'', ''shale and other tight'', or ''shale, coal and other tight''; and are considered as coal for combinations of ''coal and other tight''.

Transmission-Distribution (TD) transfer station. EPA is proposing to add a definition for Transmission Distribution (TD) transfer station to define what was previously termed ''custody transfer'' in the final rule. It was not EPA's intent for the term ''custody transfer'' to be defined in the context of ownership of gas transfer. EPA believes the new definition may be universally applied to designate which ''metering-regulating stations'' are classified as ''transmission-distribution transfer stations.'' All covered stations in the distribution segment will be collectively referred to as ''metering-regulation stations'' but the subset that require leak detection are ''transmission-distribution transfer stations.'' EPA was notified of concerns from industry that defining a transmission distribution transfer station without a threshold would include numerous small TD transfer stations that would otherwise not have been required to perform leak surveys. EPA has not included any thresholds in the proposal but we are taking comment on what an appropriate threshold would be to exclude these smaller transfer stations. Such a threshold should exempt stations with low throughputs or low emissions. Any threshold should be readily verifiable and be readily applied to all stations. Potential options for a threshold include using the inlet pressure, the design or actual flow rate of the station, or other parameters directly related to the emissions from the station. Any suggested changes should include a discussion of how many stations would be exempted from leak detection and how many would still require leak detection. Such an exemption would not preclude a station from reporting, it would only mean that leak detection is not required at that station. The stations that fall below the select threshold would still be included for evaluation against the 25,000mtCO_2e threshold through the application of an emissions factor. Natural gas distribution facilities that do not have any TD transfer stations above the threshold, would use a factor to determine their emissions and compare those emissions against the 25,000 mtCO_2e threshold.

Transmission Pipeline. We are proposing to add a definition for transmission pipeline. Transmission pipelines are clearly designated as such by the Federal Energy Regulatory Commission for interstate transmission pipelines, individual States for intrastate transmission pipelines, and the Hinshaw exemption under the Natural Gas Act for Hinshaw transmission pipelines. We propose to use this existing mechanism to clearly demarcate transmission pipelines from distribution and gathering pipelines. Finally, we believe that equipment located on designated transmission pipelines that are subject to monitoring under subpart W are easily identifiable by facility owners or operators.

Tubing Systems. Based on a question received in the early phases of implementation, we are proposing to clarify that the exclusion for piping equal to or less than one half inch diameter applies to the nominal pipe size (NPS).

Vertical Well. With the change from field level reporting to sub-basin category, EPA is proposing to add a distinction for calculating emissions from horizontal wells and vertical wells. EPA proposes that a vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well Testing Venting and Flaring. We are proposing to clarify that well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (*i.e.,* the well testing) through a choke (an orifice restriction). If well testing is conducted immediately after well completion or workover we are proposing to clarify that it is considered part of the well completion or workover.

III. Statutory and Executive Order Review

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

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

This action proposes to simplify the existing reporting methodologies in subpart W and clarify monitoring methodologies and data reporting requirements. In many cases, the proposed amendments to the reporting requirements could potentially reduce the reporting burden by making the reporting requirements conform more closely to current industry practices. In addition, while the proposed modification to one of the monitoring methodologies is not expected to increase compliance cost, it would require the reporting of information not contained in the information collection requirements to 40 CFR 98 subpart W. Therefore, the proposed amendments to the information collection requirements have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document has been assigned EPA ICR number 2376.03.

The proposed amendments to subpart I would carry out the Agency's intent to require reporting of emissions of all fluorocarbons used as heat transfer fluids in the electronics manufacturing industry. This was the intent of the subpart I reporting requirements for HTFs finalized in December 2010 (75 FR 74774), and this intent was reflected in the Information Collection Request (ICR) prepared during that rulemaking. Thus, the proposed amendments will not increase EPA or industry burden beyond that estimated in the ICR.

The Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations, 40 CFR 98 subpart W (75 FR 74458), and 40 CFR part 98 subpart I (75 FR 74774), under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0651 and 2060–0650, respectively. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

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

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

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the rule on small entities'' 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

This action includes proposed amendments to provisions in those rules that could result in reduced burden on reporters. In some cases, EPA is proposing to increase flexibility in the selection of methods use for calculating GHG's, and is also proposing to revise certain methods that may result in greater conformance to current industry practices. In addition, in this action, EPA is proposing to revise specific provisions to provide clarity on what is to be reported. Further, in this action, EPA is also proposing amendments to clarify the Agency's intent. These proposed revisions could overall reduce burden on reporters while maintaining the data quality of the information being reported to EPA. As part of the process of finalization of the subpart W and subpart I rules, EPA undertook specific steps to evaluate the effect of those final rules on small entities. Based on the proposed amendments to the subpart W and subpart I provisions, burden will stay the same or decrease, therefore EPA's determination finding of no significant economic impact on a substantial number of small entities has not changed.

D. Unfunded Mandates Reform Act (UMRA)

The proposed rule amendments do not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, the proposed rule amendments are not subject to the requirements of section 202 and 205 of the UMRA. This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Further, the proposed amendments will not impose any new requirements that are not currently required for 40 CFR part 98, and the rule amendments would not unfairly apply to small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

Few, if any, State or local government facilities would be affected by the provisions in this proposed rule. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this action.

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

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). During the finalization of subpart W and subpart I, EPA undertook the necessary steps to determine the impact of those rules on tribal entities and provided supporting documentation demonstrating the results of the Agency's analyses. The proposed rule amendments in this action do not impose any significant changes to the current reporting requirements contained in 40 CFR part 98 subpart W and 40 CFR part 98 subpart I. And in several cases, the proposed amendments to the reporting requirements would potentially reduce the reporting burden. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted tribal officials during the development of the original actions. A summary of the concerns raised during the consultation and EPA's response to those concerns is provided in Sections VIII.E and VIII.F of the preamble to the 2009 final rule and Section IV.F of the preamble to the 2010 final rule for subpart W (75 FR 74485). EPA specifically solicits additional comment on this proposed action from tribal officials.

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

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

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

This action is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

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

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

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

List of Subjects in 40 CFR Part 98

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

Dated: August 19, 2011.

Lisa P. Jackson,

Administrator.

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

PART 98—[AMENDED]

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

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

2. Section 98.1 is amended by adding 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 subpart A have the same definition as *Onshore petroleum and natural gas production owner or operator,* as defined in § 98.238 of this part.

3. Section 98.6 is amended by revising the definitions for ''Continuous bleed'' and ''Intermittent bleed pneumatic devices'' to read as follows:

§ 98.6 Definitions.

* * * * *

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

* * * * *

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

* * * * *

4. Section 98.7 is amended by removing paragraph (q).

Subpart I—[Amended]

5. Section 98.90 is amended by revising paragraph (a)(5) to read as follows:

§ 98.90 Definition of the source category.

(a) * * *

(5) Any electronics manufacturing production process in which fluorinated heat transfer fluids are used to cool process equipment, to control temperature during device testing, to clean substrate surfaces and other parts, and for soldering (*e.g.,* vapor phase reflow).

6. Section 98.92 is amended by revising paragraph (a) introductory text and paragraph (a)(5) to read as follows:

§ 98.92 GHGs to report.

(a) You must report emissions of fluorinated GHGs (as defined in § 98.6), N_2O, and fluorinated heat transfer fluids (as defined in § 98.98). The fluorinated GHGs and fluorinated heat transfer fluids that are emitted from electronics manufacturing production processes include, but are not limited to, those listed in Table I–2 to this subpart. You must individually report, as appropriate:

* * * * *

(5) Emissions of fluorinated heat transfer fluids.

* * * * *

7. Section 98.93 is amended by revising paragraph (h) introductory text and the definition of ''EH_i'' in Equation I–16 to read as follows.

§ 98.93 Calculating GHG Emissions.

* * * * *

(h) If you use fluorinated heat transfer fluids, you must report the annual emissions of fluorinated heat transfer fluids using the mass balance approach described in Equation I–16 of this subpart.

* * * * *

EH_i = Emissions of fluorinated heat transfer fluids i, (metric tons/year).

* * * * *

8. Section 98.94 is amended by revising paragraph (h) introductory text to read as follows:

§ 98.94 Monitoring and QA/QC requirements.

* * * * *

(h) You must adhere to the QA/QC procedures of this paragraph (h) when calculating annual gas consumption for each fluorinated GHG and N_2O used at your facility and emissions from the use of fluorinated heat transfer fluids.

* * * * *

9. Section 98.96 is amended by revising paragraph (r) to read as follows:

§ 98.96 Data Reporting requirements.

* * * * *

(r) For heat transfer fluid emissions, inputs to the heat transfer fluid mass balance equation, Equation I–16 of this subpart, for each fluorinated heat transfer fluid used.

* * * * *

10. Section 98.98 by removing the definition of ''Heat transfer fluids'' and adding the definition of ''Fluorinated heat transfer fluids'' in alphabetical order to read as follows:

§ 98.98 Definitions.

* * * * *

Fluorinated heat transfer fluids means fluorinated GHGs used for temperature control, device testing, cleaning substrate surfaces and other parts, and soldering in certain types of electronics manufacturing production processes. For fluorinated heat transfer fluids under this subpart I, the lower vapor pressure limit of 1 mm of Hg in absolute at 25 degrees C in the definition of *Fluorinated greenhouse* gas in 40 CFR 98.6 shall not apply. Fluorinated heat transfer fluids used in the electronics manufacturing sector include, but are not limited to, perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers.

* * * * *

11. Table I–2 to Subpart I is amended by revising the title and the second column heading to read as follows:

TABLE I–2 TO SUBPART I OF PART 98—EXAMPLES OF FLUORINATED GHGS AND FLUORINATED HEAT TRANSFER FLUIDS USED BY THE ELECTRONICS INDUSTRY

Product type	Fluorinated GHGs and fluorinated heat transfer fluids used during manufacture
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6, and HTFs (CF_3-(O-CF(CF_3)-CF_2)$_n$-(O-CF_2)$_m$-O-CF_3, C_nF_{2n+2}, C_nF_{2n+1}(O)C_mF_{2m+1}, $C_nF_{2n}O$, $(C_nF_{2n+1})_{3N}$).

Subpart W—[Amended]

12. Section 98.230 is amended by revising paragraphs (a)(2) through (a)(4), and (a)(8) 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, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2 or natural gas injection, and 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.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: Forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This 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 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

* * * * *

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

* * * * *

13. Section 98.232 is amended by:

a. Revising paragraph (c) introductory text and paragraph (c)(22).

b. Revising paragraph (e) introductory text.

c. Revising paragraph (f) introductory text.

d. Revising paragraph (g) introductory text.

e. Revising paragraph (h) introductory text.

f. Revising paragraph (i) introductory text and paragraph (i)(1).

g. Redesignating paragraphs (i)(2) through (i)(6) as paragraphs (i)(3) through (i)(7), respectively.

h. Revising newly designated paragraphs (i)(3) and (i)(4).

i. Adding new paragraph (i)(2).

j. Removing and reserving paragraph (j).

k. Revising paragraph (k).

The revisions read as follows:

§ 98.232 GHGs to report.

* * * * *

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

* * * * *

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in § 98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

* * * * *

(e) For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:

* * * * *

(f) For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:

* * * * *

(g) For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:

* * * * *

(h) LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:

* * * * *

(i) For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(2) Equipment leaks from vaults at below grade transmission-distribution transfer stations.

(3) Meters, regulators, and associated equipment at above grade metering-regulating station.

(4) Equipment leaks from vaults at below grade metering-regulating stations.

* * * * *

(j) [Reserved].

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

14. Section 98.233 is amended by:

a. In paragraph (a), revising Equation W–1 and the definitions of ''Count'' and

"GHG_i" in Equation W–1; and adding the definition of "T" in Equation W–1.

b. Adding paragraph (a)(3).

c. In paragraph (c), revising Equation W–2 and the definition of "GHG_i"; and adding the definition of "T" in Equation W–2.

d. Revising paragraphs (d) introductory text and (d)(1).

e. In paragraph (d)(3), revising Equation W–4 and removing the definition of "α" in Equation W–4.

f. Revising paragraph (e)(1)(vii).

g. Revising the definition of "1000" in Equation W–5 of paragraph (e)(2).

h. Revising paragraph (e)(6).

i. Revising paragraphs (f) introductory text, (f)(1) introductory text, and the definitions of Equation W–7 in paragraph (f)(1).

j. Revising paragraphs (f)(1)(i)(A) through (f)(1)(i)(C).

k. In paragraph (f)(2), revising Equation W–8 and the definitions of Equation W–8.

l. Removing paragraphs (f)(2)(i) and (f)(2)(ii).

m. In paragraph (f)(3), revising Equation W–9 and the definitions of Equation W–9.

n. Removing paragraphs (f)(3)(i) and (f)(3)(ii).

o. In paragraph (g), revising Equation W–10 and the definitions of Equation W–10.

p. Revising introductory texts for paragraphs (g)(1) and (g)(1)(i).

q. Removing paragraphs (g)(1)(i)(A) through (g)(1)(i)(D).

r. In paragraph (g)(1)(ii), revising paragraph (g)(1)(ii) introductory text; redesignating Equation W–11 as Equation W–11A and Equation W–12 as Equation W–11B respectively; and adding Equation W–11C.

s. Redesignating paragraphs (g)(1)(ii)(A) through (g)(1)(ii)(B) as paragraphs (g)(1)(iii) through (g)(1)(v) and revising new paragraphs (g)(1)(iii) through (g)(1)(v).

t. Removing paragraph (g)(1)(ii)(D).

u. Revising introductory texts for paragraphs (g)(3) and (g)(5).

v. In paragraph (h), revising paragraph (h) introductory text and the definitions of "N_{wo}", "f", "V_p" and "T_p" in Equation W–13.

w. Revising paragraph (i) introductory text and paragraphs (i)(1) and (i)(2).

x. In paragraph (i)(3), revising paragraph (i)(3) introductory text; redesignating Equation W–14 as Equation W–14A; revising the definition of "N" in newly redesignated Equation W–14A; and adding Equation W–14B.

y. Revising paragraph (i)(5).

z. Revising paragraph (j)(1)(vii)(B), (j)(1)(vii)(C), and (j)(3)(i).

aa. Revising paragraphs (k)(1) and (k)(2)(i).

bb. Revising paragraph (m)(1).

cc. Revising paragraph (n)(2)(ii) and (n)(2)(iii), and in paragraph (n)(4), revising equation W–21 and the definition for "Y_j".

dd. Redesignating paragraph (n)(9) as paragraph (n)(10) and adding new paragraphs (n)(9) and (n)(11).

ee. In paragraph (o)(6), revising the definition of "MT_m" in Equation W–24.

ff. In paragraph (p)(7)(i), revising the definition of "MT_m" in Equation W–28.

gg. In paragraph (q), revising equation W–30 and the definitions for "x", "EF", "GHG_i", "T_p", and revising paragraph (q)(8).

hh. In paragraph (r), revising the definitions of "$Count_s$", "EF_s", and "GHG_i" in Equation W–31.

ii. Revising paragraphs (r)(2)(i)(A), (r)(6)(i), (r)(6)(ii) introductory text, Equation W–32, and the definitions of Equation W–32.

jj. Revising introductory texts for paragraphs (t), (t)(1), and (t)(2).

kk. Revising paragraph (u) introductory text and paragraph (u)(2).

ll. In paragraph (v), revising paragraph (v) introductory text and the definitions of "$Mass_{s,i}$", "$E_{s,i}$", and "ρ_i" in Equation W–36.

mm. Revising introductory texts for paragraphs (z), (z)(1), (z)(2), (z)(2)(i), and (z)(2)(ii).

nn. Adding paragraphs (z)(1)(i) and (z)(1)(ii).

The revisions read as follows:

§ 98.233 Calculating GHG emissions.

(a) * * *

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

* * * * *

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) and (a)(2) of this section.

* * * * *

GHG_i = For onshore petroleum and natural gas production facilities, onshore natural gas transmission compression, and underground natural gas storage, concentration of GHG_i, CH_4, or CO_2, in natural gas as defined in paragraph (u)(2)(i) of this section.

* * * * *

T = Total number of hours in the operating year the devices were operational.

* * * * *

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

* * * * *

(c) * * *

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

* * * * *

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

* * * * *

T = Total number of hours in the operating year the pumps were operational.

* * * * *

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

* * * * *

(1) *Calculation Methodology 1.* If you operate and maintain a 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 Methodology 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 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 Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGRs.

* * * * *

(3) * * *

$$E_{a,CO2} = \left[\frac{V}{1-(Vol_I - Vol_O)}\right] * (Vol_I - Vol_O) \quad \text{(Eq. W-4)}$$

* * * * *

(e) * * *

(1) * * *

(vii) Use of stripping gas.

* * * * *

(2)

* * * * *

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

* * * * *

(6) For glycol dehydrators, both CH_4 and CO_2 mass emissions shall be calculated from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

* * * * *

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

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

* * * * *

$E_{a,n}$ = Annual natural gas emissions for wells of the same tubing diameter grouping and pressure grouping at actual conditions in cubic feet.

$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter grouping p and pressure grouping q during the year.

$FR_{h,t}$ = Average flow rate in cubic feet per hour of a measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

h = Total number of different tubing diameter groupings.

p = Tubing diameter grouping 1 through h.

t = Total number of pressure groupings.

q = Pressure grouping 1 through t.

* * * * *

(i) * * *

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter grouping and pressure grouping in each sub-basin category by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.

(B) This average flow rate per hour is applied to all wells in the same pressure grouping that have the same tubing diameter grouping, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting sub-basin category starting the first calendar year of data collection. For a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.

(2) * * *

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{q,p} - 1.0\right)\times Z_{q,p}\right)\right] \quad \text{(Eq. W-8)}$$

Where:

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

W = Total number of wells with well venting for liquids unloading at the facility.

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

CD_P = Casing diameter for each well, p, in inches.

WD_P = Well depth from the lowest packer to the bottom of the well, in feet.

SP_P = Shut-in pressure for each well, p, in pounds per square inch atmosphere (psia).

V_P = Number of vents per year per well, p.

SFR_P = Average sales flow rate of gas well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the sales flow rate at standard conditions.

$HR_{Q,PW}$ = Hours that each well,p, was left open to the atmosphere during unloading, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{Q,P}$ = If $HR_{Q,P}$ is less than 1.0 then $Z_{Q,P}$ is equal to 0. If $HR_{Q,P}$ is greater than or equal to 1.0 then $Z_{Q,P}$ is equal to 1.

(3) * * *

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_q \times \left(HR_{q,p} - 0.5\right)\times Z_{q,p}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

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

W = Total number of wells with well venting for liquids unloading at the facility.

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

TD_P = Tubing diameter for each well, p,in inches.
WD_P = Tubing depth to plunger bumper for each well, p, in feet.
SP_P = Sales line pressure for each well, p, in pounds per square inch atmospheric (psia).
V_P = Number of vents per year for each well, p.
SFR_P = Average sales flow rate of each gas well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the sales flow rate at standard conditions.
$HR_{Q,P}$ = Hours that each well, p, was left open to the atmosphere during each unloading, q.
0.5 = Hours for average well to blowdown tubing volume at sales line pressure.
$Z_{Q,P}$ = If $HR_{Q,P}$ is less than 0.5 then $Z_{Q,P}$ is equal to 0. If $HR_{Q,P}$ is greater than or equal to 0.5 then $Z_{Q,P}$ is equal to 1.

* * * * *

(g) * * *

$$E_{s,n} = \sum_{p=1}^{W} \left[T_p \times FRM \times PR_p - EnF_p - SG_p \right] \quad \text{(Eq. W-10)}$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for each sub-basin and well type combination.
T_p = Cumulative amount of time in hours of each well (p) completion or workover venting in a sub-basin and well type combination during the reporting year.
FRM = Venting to 30-day production ratio from Equation W–12.
PR_p = First 30-day average production flow rate in standard cubic feet per hour of each well (p), under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.
EnF_p = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well (p). If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2, then EnF is 0.
SG_p = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline for well p as per paragraph (g)(3) of this section. If no gas was recovered for sales, SG is 0.
W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using measurement(s) from either of the calculation methodologies described in this paragraph (g)(1) of this section. The number of measurements shall be determined as follows: One measurement for less than or equal to 25 completions/workovers; two measurements for 26 to 50 completions/workovers; three measurements for 51 to 100 completions/workovers; four measurements for 101 to 250 completions/workovers; and five measurements for greater than 250 completions/workovers.

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

(ii) *Calculation Methodology 2.* For one horizontal well completion and one vertical well completion in each gas producing sub-basin category and for one well horizontal workover and one vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W–11A of this section for subsonic flow or Equation W–11B of this section for sonic flow. Use Equation W–11C of this section to determine whether flow is sonic or subsonic. If the value of R in Equation W–11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

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

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.
A = Cross sectional area of orifice (m_2).
P_1 = Upstream pressure (psia).
T_u = Upstream temperature (degrees Kelvin).
P_2 = Downstream pressure (psia).
3430 = Constant with units of m_2/(sec_2 * K).
1.27*105 = Conversion from m_3/second to ft_3/hour.

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-11B)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.
A = Cross sectional area of orifice (m_2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of m_2/(sec_2 * K).
1.27*105 = Conversion from m_3/second to ft_3/hour.

$$R = P1 / P2 \quad \text{(Eq. W-11C)}$$

Where:

R = Pressure ratio

P_1 = Pressure upstream of the restriction orifice in pounds per square inch absolute.

P_2 = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) The emissions to 30-day production ratio is calculated using Equation W–12 of this section.

$$FRM = \frac{\sum_{p=1}^{W} FR_p}{\sum_{p=1}^{W} PR_p} \qquad \text{(Eq. W-12)}$$

Where:

FRM = Emissions to 30-day production ratio.

FR_p = Measured flow rate from Calculation Methodology 1 or estimated flow rate from Calculation Methodology 2 in standard cubic feet per hour for well(s) p for each sub-basin and well type (horizontal or vertical) combination.

PR_p = First 30-day production rate in standard cubic feet per hour for each well p that was measured in the sub-basin and well type combination.

W = Number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type formation.

(iv) The flow rates for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of venting of each of these wells.

(v) New flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

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

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

(ii) [Reserved].

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

* * * * *

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

* * * * *

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

* * * * *

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

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

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

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

* * * * *

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

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

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

(3) Calculate the total annual venting emissions for each equipment type using either Equation W–14A or W–14B of this section.

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

Where:

* * * * *

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

* * * * *

$$E_{s,n} = \sum_{p=1}^{N}\left[V_v\left(\frac{(459.67+T_s)(P_{a,s,p}-P_{a,e,p})}{(459.67+T_a)P_s}\right)\right] \quad \text{(Eq. W-14B)}$$

Where:

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

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

V_v = Total volume of blowdown equipment chamber (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown "i."

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

T_s = Temperature at standard conditions (°F).

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

P_s = Absolute pressure at standard conditions (psia).

$P_{a,s,p}$ = Absolute pressure at actual conditions in the blowdown equipment chamber (psia) at the start of the blowdown "p".

$P_{a,e,p}$ = Absolute pressure at actual conditions in the blowdown equipment chamber (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases.

* * * * *

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

(j) * * *

(1) * * *

(vii) * * *

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

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

* * * * *

(3) * * *

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

* * * * *

(k) * * *

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or high volume sampler according to methods in § 98.234(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) * * *

(i) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph § 98.233(k)(1) of this section to detect continuous leakage, this serves as the measurement.

(m) * * *

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

* * * * *

(n) * * *

(2) * * *

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

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

* * * * *

(n) * * *

$$E_{a,CO2}\,(combusted) = \sum_{J=1}^{5}\left(\eta * V_a * Y_j * R_j\right) \quad \text{(Eq. W-21)}$$

* * * * *

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

* * * * *

(9) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions for the flare by following the Tier 4 Calculation Methodology 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 emissions, the requirements specified in paragraphs (n)(1) through (n)(7) are not required. 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 Methodology in subpart C of this part (General Stationary Fuel Combustion).

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

(11) If source types in § 98.233 use Equations W–19 through W–21 of this section, use estimate of emissions under actual conditions for the parameter, V_a, in these equations.

(o) * * *

(6) * * *

* * * * *

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

* * * * *

(p) * * *

(7) * * *

(i) * * *

* * * * *

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

* * * * *

(q) * * *

* * * * *

$$E_{s,i} = GHG_i * \sum_{p=1}^{x} \left(EF * T_p\right) \quad \text{(Eq. W-30)}$$

* * * * *

x = Total number of each equipment leak source.

* * * * *

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; 98.230(a)(4) and (a)(5), GHG_i equals 0.974 for CH_4 and 1.0×10^{-2} for CO_2; for facilities listed in § 98.230(a)(6) and (a)(7), GHG_i equals 1 for CH_4 and 0 for CO_2; and for facilities listed in § 98.230(a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

* * * * *

(8) Natural gas distribution facilities for above grade transmission-distribution transfer stations, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(r) * * *

* * * * *

$Count_s$ = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Underground natural gas storage shall count the components listed for population emission factors in Table W–4. LNG Storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the respective component for each emission factor as described in paragraph (r)(6) of this section.

EF_s = Population emission factor for the specific source, as listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for meter/regulator runs at above grade metering-regulating stations is determined in Equation W–32 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities listed in § 98.230(a)(4) and (a)(5), GHG_i equals 0.952 for CH_4 and 1.0×10^{-2} for CO_2; for facilities listed in § 98.230(a)(6) and (a)(7), GHG_i equals 1 for CH_4 and 0 for CO_2; and for facilities listed in § 98.230(a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

* * * * *

(2) * * *

(i) * * *

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad.

* * * * *

(6) * * *

(i) Below grade metering-regulating stations (including below grade T–D transfer stations); distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart.

(ii) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation W–32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation W–31. The facility wide emission factor in Equation W–32 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section and the count of meter/regulator runs located at above grade transmission-distribution transfer stations.

$$EF = \sum \frac{E_{s,i} \div 8760}{Count} \quad \text{(Eq. W-32)}$$

Where:

EF_i = Facility emission factor for a meter/regulator run at above grade metering-regulating for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG i emissions, CO_2 or CH_4 at standard condition from all equipment leak sources at all above grade TD transfer stations, from paragraph (q) of this section.

Count = Total number of meter/regulator runs at all TD transfer stations.

8760 = Conversion to hourly emissions

* * * * *

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using

actual natural gas emission temperature and pressure, and Equation W–33 of this section.

* * * * *

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W–34 of this section.

* * * * *

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

* * * * *

(2) For Equation W–35 of this section, the mole fraction, Mi, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on available analyses in each of the sub-basin categories.

(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).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mole fraction in natural gas stored in LNG storage facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities. For export facilities that receive gas from transmission pipelines, you may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W–36 of this section.

* * * * *

$Mass_{s,i}$ = GHG i (either CH_4, CO_2, or N_2O) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0520 kg/ft^3 for CO_2 and N_2O, and 0.0190 kg/ft^3 for CH_4 at 68 °F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

* * * * *

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (z)(3) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C–1, calculate emissions according to (z)(1)(i). If the fuel is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation methodology described in (z)(1)(i) and you may use the emission factor provided for natural gas as listed in Table C–1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 But per standard cubic feet, calculate emissions according to (z)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (z)(2).

(i) For fuels listed in Table C–1 or a blend containing one more fuels listed in Table C–1, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in 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.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in 98.236(c)(19) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

15. Section 98.234 is amended by:

a. Revising paragraphs (a)(1), (a)(2), and (a)(5).

b. Removing and reserving paragraph (a)(4).

c. Revising paragraph (c) introductory text and paragraph (d)(3).

§ 98.234 Monitoring and QA/QC requirements.

(a) * * *

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the *Alternative work practice for monitoring equipment leaks*, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the 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 is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21*. Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

* * * * *

(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 non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

* * * * *

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag must be of sufficient size that the entire emissions volume can be encompassed for measurement.

* * * * *

(d) * * *

(3) 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).

16. Section 98.236 is amended by:

a. Revising paragraphs (a) introductory text and (a)(8).

b. Revising paragraph (b).

c. Revising paragraphs (c) introductory text, (c)(1)(iv), (c)(2)(ii), and (c)(3)(ii) through (c)(3)(v); and adding paragraphs (c)(3)(vi) and (vii).

d. Revising paragraphs (c)(4)(i)(H) and (C)(4)(i)(J); and adding paragraphs (c)(4)(i)(K) and (c)(4)(i)(L).

e. Revising paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(C); and adding paragraph (c)(4)(ii)(D).

f. Revising paragraph (c)(4)(iii)(B).

g. Revising paragraphs (c)(5) introductory text, (c)(5)(iii), and (c)(5)(vi); and adding paragraph (c)(5)(vii).

h. Revising paragraphs (c)(6) introductory text, (c)(6)(i) introductory text, (c)(6)(i)(B), (c)(6)(i)(D), (c)(6)(i)(G), and (c)(6)(i)(H); and adding paragraph (c)(6)(ii)(I).

i. Revising paragraphs (c)(6)(ii)(B) and (c)(6)(ii)(D); and adding paragraph (c)(6)(ii)(E).

j. Revising paragraphs (c)(7)(i) and (c)(7)(ii); and adding paragraph (c)(7)(iii).

k. Revising paragraphs (c)(8)(i) introductory text and (c)(8)(i)(J); and adding paragraphs (c)(8)(i)(K) through (c)(8)(i)(M).

l. Revising paragraphs (c)(8)(ii) introductory text, (c)(8)(ii)(D), and (c)(8)(ii)(G); and adding paragraphs (c)(8)(ii)(H) and (c)(8)(ii)(I).

m. Revising paragraphs (c)(8)(iii) introductory text and (c)(8)(iii)(F); and adding paragraphs (c)(8)(iii)(G) and (c)(8)(iii)(H).

n. Adding paragraph (c)(8)(iv)(B).

o. Revising paragraphs (c)(9)(i) and (c)(9)(ii); and adding paragraph (c)(9)(iii).

p. Revising paragraphs (c)(10) introductory text and (c)(10)(iv); and adding paragraph (c)(10)(v).

q. Revising paragraph (c)(11) introductory text and (c)(11)(iii); and adding paragraph (c)(11)(iv).

r. Revising paragraph (c)(12)(vi) and adding paragraphs (c)(12)(vii) through (c)(12)(xi).

s. Revising paragraphs (c)(15)(i)(B) and (c)(15)(i)(C).

t. Revising paragraphs (c)(15)(ii)(A) through (c)(15)(ii)(C).

u. Revising paragraphs (c)(16)(i) through (c)(16)(iv), (c)(16)(vi), and (c)(16)(xv).

v. Removing and reserving paragraph (c)(16)(v).

w. Adding paragraphs (c)(16)(xvi) through (c)(16)(xx).

x. Revising paragraph (c)(17)(v) and adding paragraph (c)(17)(vi).

y. Revising paragraph (c)(18) introductory text and paragraph (c)(18)(iii).

z. Revising paragraph (c)(19)(iii) and (c)(19)(vi).

aa. Adding paragraph (e).

The revisions read as follows:

§ 98.236 Data Reporting Requirements.

* * * * *

(a) Report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section.

* * * * *

(8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons CO_2e per year at standard conditions) individually for all the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type. If a facility operates under more than one industry segment, each piece of equipment should be reported under its respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring the gas. Both the vented and flared emissions will be reported under the respective source type and not under the flare source type.

(1) * * *

(iv) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) * * *

(ii) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for all natural gas driven pneumatic pumps combined.

(3) * * *

(ii) For Calculation Methodology 1 and Calculation Methodology 2 of § 98.233(d), annual average fraction of CO_2 content in the vent from the acid gas removal unit (refer to § 98.233(d)(6)).

(iii) For Calculation Methodology 3 of § 98.233(d), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to § 98.233(d)(7) and (d)(8)).

(iv) Report the annual quantity of CO_2, expressed in metric tons CO_2e, that was recovered from the AGR unit and transferred outside the facility.

(v) Report annual CO_2 emissions for the AGR unit, expressed in metric tons CO_2e.

(vi) A unique name or ID number for the AGR unit.

(vii) An indication of which calculation methodology was used for the AGR.

(4) * * *

(i) * * *

(H) Concentration of CH_4 and CO_2 in wet natural gas.

* * * * *

(J) For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(K) For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons CO_2e for each gas.

(L) A unique name or ID number for the glycol dehydrator.

(ii) * * *

(B) Which vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(C) Report annual CO_2 and CH_4 emissions at the facility level that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with a throughput of less than 0.4 MMscfd.

(D) Report annual CO_2, CH_4, and N_2O emissions at the facility level that resulted from the flaring of process gas, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with a throughput of less than 0.4 MMscfd.

(iii) * * *

(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading (refer to Equations W–7, W–8 and W–9 of § 98.233), report the following by each well tubing diameter grouping and pressure grouping within each sub-basin category:

* * * * *

(iii) Cumulative number of unloadings vented to the atmosphere.

* * * * *

(vi) Report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each gas, for each tubing diameter and pressure grouping within each sub-basin category.

(vii) When using Calculation Methodology 1, casing diameter, depth and pressure of each well selected to represent emissions in that tubing size and pressure combination (refer to Equation W–7 of § 98.233).

(6) For well completions and workovers, report the following for each sub-basin category:

(i) For gas well completions and workovers with hydraulic fracturing by sub-basin and well type (horizontal or vertical) combination (refer to Equation W–10 of § 98.233):

* * * * *

(B) Average flow rate of the measured well completion venting in cubic feet per hour (refer to Equation W–12 of § 98.233).

* * * * *

(D) Average flow rate of the measured well workover venting in cubic feet per hour (refer to Equation W–12 of § 98.233).

* * * * *

(G) Report number of completions and number of workovers employing reduced emissions completions and engineering estimate based on best available data of the amount of gas recovered to sales.

(H) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(I) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons CO_2e for each gas.

* * * * *

(B) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.

* * * * *

(D) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(E) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons CO_2e for each gas.

(7) * * *

(i) Total number of blowdowns per unique volume type in calendar year.

(ii) Annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each gas, for each unique volume type, at each blowdown stack.

(iii) A unique name or ID number for the blowdown vent stack.

(8) * * *

(i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of § 98.233(j), report the following by sub-basin category, unless otherwise specified:

* * * * *

(J) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, for each wellhead gas-liquid separator or storage tank using Calculation Methodology 1 or 2 of § 98.233(j).

(K) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, for each wellhead gas-liquid separator or storage tank using Calculation Methodology 1 or 2 of § 98.233(j).

(L) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, for each wellhead gas-liquid separator or storage tank using Calculation Methodology 1 or 2 of § 98.233(j).

(M) A unique name or ID number for each wellhead gas liquid separator or storage tank.

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of § 98.233(j), report the following by sub-basin category:

* * * * *

(D) Sales oil API gravity range for wells in (c)(8)(ii)(B) and (c)(8)(ii)(C) of this section, in degrees.

* * * * *

(G) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(H) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(I) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, at the sub-basin level for

Calculation Methodology 3 and 4 of § 98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of § 98.233(j) Equation W–15 of § 98.233, report the following:

* * * * *

(F) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(G) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(H) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(iv) * * *

(B) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for improperly functioning dump valves.

(9) * * *

(i) For each transmission storage tank, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(ii) For each transmission storage tank, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons CO_2e for each gas.

(iii) A unique name or ID number for the transmission storage tank.

(10) For well testing venting and flaring (refer to Equation W–17 of § 98.233), report the following:

* * * * *

(iv) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from well testing venting.

(v) Report annual CO_2, CH_4, and N_2O emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation W–18 of § 98.233), report the following for each basin:

* * * * *

(iii) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from associated natural gas venting.

(iv) Report annual CO_2, CH_4, and N_2O emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from associated natural gas flaring.

(12) * * *

(vi) Report uncombusted CH_4 emissions, in metric tons CO_2e (refer to Equation W–19 of § 98.233).

(vii) Report uncombusted CO_2 emissions, in metric tons CO_2e (refer to Equation W–20 of § 98.233).

(viii) Report combusted CO_2 emissions, in metric tons CO_2e (refer to Equation W–21 of § 98.233).

(ix) Report N_2O emissions, in metric tons CO_2e.

(x) A unique name or ID number for the flare stack.

(xi) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(15) * * *

(i) * * *

(B) For onshore natural gas processing, range of concentrations of CH_4 and CO_2 (refer to Equation W–30 of § 98.233).

(C) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas (refer to Equation W–30 of § 98.233), by equipment type.

(ii) * * *

(A) For source categories § 98.230(a)(4), (a)(5), (a)(6), (a)(7), and (a)(8), total count for each type of leak source in Tables W–2, W–3, W–4, W–5, and W–6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to § 98.230 paragraph (a)(2)), total count for each type of major equipment in Table W–1B and Table W–1C of this subpart, by sub-basin category.

(C) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas (refer to Equation W–31 of § 98.233), by equipment type.

(16) * * *

(i) Number of above grade T–D transfer stations.

(ii) Number of below grade T–D transfer stations.

(iii) Number of above grade metering-regulating stations (this count will include above grade T–D transfer stations).

(iv) Number of below grade metering-regulating stations (this count will include below grade T–D transfer stations).

(v) [Reserved].

(vi) Above grade metering-regulating station leak factor (refer to Equation W–32 of § 98.233).

* * * * *

(xv) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade T–D transfer stations combined.

(xvi) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade T–D transfer stations combined.

(xvii) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade metering-regulating stations (including T–D transfer stations) combined.

(xviii) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade metering-regulating stations (including T–D transfer stations) combined.

(xix) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution mains combined.

(xx) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution services combined.

(17) * * *

(v) For each EOR pump, report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each gas.

(vi) A unique name or ID for the EOR pump.

(18) For EOR hydrocarbon liquids dissolved CO_2 for each sub-basin category (refer to Equation W–38 of § 98.233), report the following:

* * * * *

(iii) Report annual CO_2 emissions at the sub-basin level, expressed in metric tons CO_2e.

(19) * * *

(iii) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons CO_2e for each gas, by type of unit.

* * * * *

(vi) Report annual CO_2, CH_4, and N_2O emissions from internal combustion units, expressed in metric tons CO_2e for each gas, by type of unit.

* * * * *

(e) For onshore petroleum and natural gas production, report the average API gravity, average gas to oil ratio, and average low pressure separator pressure for each sub-basin category.

17. Section 98.237 is amended by adding paragraph (e) to read as follows:

§ 98.237 Records that must be retained.

* * * * *

(e) The records required under § 98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

18. Section 98.238 is amended by:

a. Revising the definitions of ''Facility with respect to natural gas distribution for purposes of this subpart and subpart A'', ''Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A'', ''Farm Taps'', and ''Transmission pipeline''.

b. Adding definitions of ''Associated with a single well-pad'', ''Distribution pipeline'', ''Flare'', ''Forced extraction'', ''Horizontal well'', ''Natural gas'', ''Metering-regulating station'', ''Pressure groupings'', ''Sub-basin category'', ''Transmission-distribution transfer station'', ''Tubing diameter groupings'', ''Tubing systems'', ''Vertical well'', and ''Well testing venting and flaring''.

c. Removing the definition of ''Field''.

The revisions read as follows:

§ 98.238 Definitions.

* * * * *

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. This does not include storage and condensate tanks that are located downstream of the point of combination.

* * * * *

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

* * * * *

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a well-pad or associated with a well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

* * * * *

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

* * * * *

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, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

* * * * *

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

* * * * *

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

* * * * *

Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

* * * * *

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following four formation types as designated by 18 CFR 270.305: conventional with >0.1 millidarcy permeability, and unconventional with ≤0.1 millidarcy permeability. Unconventional formation types are either shale, coal seam, or other tight reservoir rock. Wells producing from more than one unconventional formation type shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. Unconventional wells producing in two or more formation types of ''shale and coal seam'', ''shale and other tight'', or ''shale, coal seam, and other tight''; are considered shale. In addition, unconventional wells producing in ''coal seam and other tight'' formations are considered coal.

Transmission-distribution (TD) transfer station means a meter-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717(w)(1994).

Tubing diameter groupings are defined as follows: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

* * * * *

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (*i.e.,* the well testing) through a choke (an orifice restriction). If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

19. Table W–7 to subpart W is amended by:

a. Revising the entries for ''Leaker Emission Factors—Above Grade M&R at City Gate [1] Stations Components, Gas Service,'' ''Population Emission Factors—Below Grade M&R [2] Components, Gas Service [3],'' ''Population Emission Factors—Distribution Mains, Gas Service [4],'' and ''Population Emission Factors—Distribution Services, Gas Service [5].''

b. Removing Footnote 1.

c. Redesignating Footnotes 2, 3, 4, and 5 as Footnotes 1, 2, 3, and 4.

The revisions read as follows:

*	*	*	*	*	*	*
Leaker Emission Factors—Transmission-distribution Transfer Station[1] Components, Gas Service						
*	*	*	*	*	*	*
Population Emission Factors—Below Grade Metering-Regulating station[1] Components, Gas Service[2]						
*	*	*	*	*	*	*
Population Emission Factors—Distribution Mains, Gas Service[3]						
*	*	*	*	*	*	*
Population Emission Factors—Distribution Services, Gas Service[4]						
*	*	*	*	*	*	*

[1] Excluding customer meters.
[2] Emission Factor is in units of ''scf/hour/station.''
[3] Emission Factor is in units of ''scf/hour/mile.''
[4] Emission Factor is in units of ''scf/hour/number of services.''

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