VOLUME 8: COMPLIANCE AND ENFORCEMENT

8.0 COMPLIANCE AND ENFORCEMENT

No Comments Received.

8.1 COMPLIANCE ASSISTANCE

Comment Number: EPA-HQ-OAR-2009-0923-1011-4
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
IV. Proposed Rule Section 98.231 Applicability Analysis.—(KEY ISSUE) EPA must provide flexibility to regulated facilities with respect to initial year applicability analysis. El Paso requests the EPA consider two screening methods to assist with the initial year applicability determination. This proposal differs from the INGAA proposal. In addition, El Paso requests that EPA promulgate a safe harbor provision for the first year of reporting. EPA can draw from prior regulatory precedent granted by the Federal Energy Regulatory Commission (FERC). The FERC granted a one-year safe harbor provision when it issued Order No. 704, which requires the reporting of natural gas transactions (FERC Form No. 552). This provision gave the regulated community the benefit of a rebuttable presumption that the data provided was accurate and submitted in good faith and provided assurance that the regulatory agency (the FERC) would not impose penalties for errors in reporting.

Response: For a response to this comment, please see the response to EPA-HQ-OAR-2009-0923-1011-30.

Comment Number: EPA-HQ-OAR-2009-0923-1011-30
Organization: El Paso Corporation
Commenter: Fiji George
Comment: Section 98.231 Applicability Analysis: EPA must provide flexibility to regulated facilities with respect to applicability determination of Subpart W rule. El Paso proposes two screening methods to assist with determination.

EPA has not proposed a “screening” method to determine initial applicability to the rule but instead relies on EPA proposed monitoring methods to make the determination of applicability to the rule (per Subpart A provisions). The lack of a proposed screening method is a significant gap with respect to an important aspect of compliance with Subpart W for entities that do not currently have data collected using EPA’s proposed methods (which we determined, will be most entities). El Paso proposes two alternative screening methods:

1) A 10,000 metric tons CO_2e threshold established based on combustion emissions using procedures outlined in Subpart C; or

2) Allow use of best available data to estimate GHG emissions and determine applicability against 25,000 metric tons CO_2e threshold.

In addition, we request that EPA include a safe-harbor provision under both cases.

A company would have to conduct proposed monitoring at all its facilities to assess applicability to the rule. Our current estimates of 156 facilities potentially subject to Subpart W are based on the use of best available methodologies gained through our participation in the California Climate Action Registry (CCAR) and Department of Energy 1605(b) emissions inventory programs.

Without a screening method to assess initial applicability, a company like El Paso with potential of over 150 applicable facilities operating in multiple states is subject to significant uncertainty related to the actual applicability of the rule to its facilities. Such uncertainties will result in significant compliance burden and hamper effective compliance planning.
A. Screening at 10,000 metric tons threshold based on Subpart C emissions:

We recommend that EPA permanently establish a “screening” threshold of 10,000 metric tons CO_2e per year based on emissions from combustion. That is, any facility with combustion emissions (Subpart C) less than 10,000 metric tons would not be subject to Subpart W. We feel this initial screening threshold is justifiable since repeated inventories conducted by the EPA indicate methane emissions are approximately half of the total emissions from the natural gas sector, and 10,000 metric tons is less than half the 25,000 metric tons threshold for the monitoring and reporting rule. EPA estimates over 351 million metric tons[80] from facilities subject to the proposed rule and over 415 million metric tons[81] from the entire sector. While these estimates are almost double of EPA’s official inventory[82] presented below in Table 3, the breakdown between methane and CO_2 related emissions remain at about 40% to 60% for the overall natural gas sector. Therefore, a 10,000 metric tons threshold based on combustion emissions is justifiable and provides adequate buffer considering the reporting threshold of 25,000 metric tons. Such a “screening” threshold will enable companies to focus on potential major sources and not divert significant resources to confirming applicability or non-

[80] Preamble Page 18612

[81] Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions under Subpart W Supplemental Rule (EPA– HQ–OAR–2009–0923). Table 4-6.

[82] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2008.

applicability of smaller facilities.

Table 3: 2008 Greenhouse Gas Emissions for the Natural Gas Industry and the U.S. (Tg CO_2 equivalent)

	Energy Related CO_2 Emissions	Non-Combustion CO_2 Emissions	CO_2	CH_4	Total CO_2e
Production	47.5	8.5	56.0	14.1	70.1
Processing	19.5	21.4	40.9	13.0	53.9
Transmission and Storage	35.4	0.1	35.5	39.4	74.9
Distribution	0	0	0.0	29.9	29.9
Gas Industry Total	102.4	30.0	132.4	96.4	228.8
U.S. Total			**5,905.5**	**567.3**	**6,946.1**
Gas Industry Share of U.S.			2.2%	17.0%	3.3%
Transmission Share of U.S.			0.6%	6.9%	1.1%

This approach of basing initial screening on a 10,000 metric tons Subpart C threshold is El Paso’s preferred approach in that it presents a relatively clear, easily enforceable screening tool. In the alternative, EPA could consider a screening approach based on best available data, as outlined below. The 10,000 metric tons Subpart C screening method is, however, El Paso’s preferred approach due to its clarity and ease of application.

B. Screening based on best available data:

In the alternative, until monitoring has been conducted at a facility, EPA should allow potentially affected Subpart W sources to employ best available data at a facility or onshore production “reporting area” level to estimate GHG emissions and determine applicability against the 25,000 metric tons threshold based on the estimated emissions. The best available data includes 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), The Climate Registry, California Climate Action Reserve and corporate industry protocols developed by the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association and measurement data developed internally by the reporters.

Companies should be allowed to use these best available data to estimate total emissions from facilities or onshore production reporting areas for which monitoring at Subpart W facilities has not yet been conducted, either because the rule is new or because the facilities have not yet been estimated to exceed 25,000 metric tons based on best available methods. Companies should be permitted to employ the estimated results to decide whether those facilities that have emissions over 25,000 metric tons. Once a facility’s estimated emissions based on best available methods exceed 25,000 metric tons, the first year monitoring methods would be carried out per the final rule at these “screened” facilities and reports for the first year will be from these facilities that have been “screened” to emit over 25,000 metric tons CO2e.

C. Safe harbor provision for screening methods:

Finally, El Paso requests a "safe harbor" provision be added under the final Subpart W rules. As explained above, the proposed methods will employ screening techniques for applicability determination in the first year. El Paso requests that EPA promulgate a safe harbor provision for companies using any reasonable screening techniques. EPA can draw from such prior regulatory precedence granted by the Federal Energy Regulatory Commission (FERC). The FERC granted a one-year safe harbor provision after issuing Order No. 704, which requires the reporting of natural gas transactions (FERC Form No. 552). This allowed the respondents to "benefit from a rebuttable presumption that the data provided is accurate and submitted in good faith. Further, we [the FERC] do not intend to penalize respondents for errors in reporting on Form No. 552 provided that respondents use reasonable efforts to comply with the regulations regarding and instructions for Form No. 552. We [the FERC] emphasize that the Commission expects respondents submitting Form No. 552 in 2009 to do so in good faith and on a timely basis."

Such safe harbor provision will provide the necessary certainty for companies while limiting the risk of potential retroactive enforcement in the event a facility initially determined not to be applicable to Subpart W based on the screening methods, results with emissions > 25,000 metric tons CO2e using EPA's final monitoring and estimation methods.

Response: EPA has reviewed the comment, and agrees that a screening tool should be developed to serve as a guide to determining applicability under today's final rule. The threshold for today's final rule is 25,000 metric ton CO_2e, a threshold supported by many industry stakeholders since it sufficiently captures the majority of GHG emissions in the United States, while excluding most of the smaller facilities and sources. To facilitate the screening, similar to what the Agency has already provided for other subparts of the Mandatory Reporting Program to help reporters assess their applicability to the GHG reporting program, EPA plans to develop voluntary screening tools for each petroleum and natural gas industry segment. EPA anticipates that such tools would be based on easily determined inputs such as major equipment or operational counts. The tools would be a guide to determine those facilities that are well below the reporting threshold, those above, and those close to the threshold who will need to collect further data to make a proper determination. EPA plans to place the screening tool for subpart W on the following website:
http://www.epa.gov/climatechange/emissions/GHG-calculator/index.html.

Finally, with regard to the request for a safe harbor provision in using the screening tools, while the tools would be designed to provide help to potential reporters for complying with the rule, compliance with all Federal, State, and Local laws and regulations remain the sole responsibility of each facility owner or operator subject to those laws and regulations. As regards to the safe harbor provision in monitoring and collecting relevant data to report, EPA has in today's final rule provided monitoring methods that are in most cases already in use in the industry, including the use of emissions factors across several emissions sources. Therefore, EPA does not see any need for providing a safe harbor. However, EPA has determined that for specified emissions sources for certain industry segments, some reporters may need more time to comply with the monitoring and QA/QC requirements of subpart W. In such cases, EPA concluded that providing best available monitoring methods is reasonable where required for a specific period of reporting. EPA has extensively detailed when and how reporters may use best available monitoring methods in Section II.F of the preamble to today's final rule. Given the BAMM provisions, EPA does not deem it necessary to provide safe harbor for the monitoring methods in today's final rule. Finally, in regard to safe harbor for errors in reporting, please see response to EPA-HQ-OAR-2008-0508-0952-1, excerpt 54.

Comment Number: EPA-HQ-OAR-2009-0923-1167-36
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment: The Proposed Rule essentially requires that Subpart W emission estimation methods (monitoring and direct measurement) be applied to every industry segment-specific source within an onshore petroleum and natural gas production reporting area every year. A screening method that provides reasonable compliance certainty is needed to avoid unnecessary compliance risk, implementation complexity, and financial burden.

Noble strongly recommends that a streamlined applicability screening method be included in the rule for natural gas sector sources to preclude the need for monitoring and measurement in reporting areas that fall below the applicability threshold. By defining an appropriate screening method and conservative screening emission threshold to identify affected reporting areas, compliance certainty can be assured and unnecessary measurement and monitoring can be avoided.

Noble believes a first tier screening estimate for onshore petroleum and natural gas production using a combination of API compendium emission estimation methods, and Natural Gas STAR and area specific emission factors with a threshold of 20,000 tonne CO2e per year is a reasonable screening approach. This approach would provide small reporting areas with relief from the extensive emission calculation methods, and provide compliance and reporting certainty.

Noble offers it assistance to EPA for future industry studies and data collection to refine screening tool(s) that will ensure reporting certainty for onshore petroleum and natural gas production owners and operators.

Response: EPA agrees with the commenter that a screening tool would assist reporters in threshold determination. EPA plans to develop voluntary screening tools for each petroleum and natural gas industry segment, which will be web-based as is consistent for other EPA rulemakings. For more details, please see response to EPA-HQ-OAR-2009-0923-1011-30.

Comment Number: EPA-HQ-OAR-2009-0923-1010-3
Organization: Oklahoma Independent Petroleum Association
Commenter: Burck Halter

Comment: The proposed rule does not provide a simplified method for oil and gas businesses operating production sites to determine applicability. EPA needs to develop screening tools to help oil and gas operators determine applicability without the need to hire consultants. The applicability tools need to be well defined and easy to understand so that all crude oil and natural gas operators can easily apply it to their production sites. For example, EPA needs to establish production thresholds/throughputs such as barrels of oil per day and thousands of cubic feet of gas per day at which productions sites are exempt from further burdensome and costly data collection. This would be similar to Subpart C of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) establishing an aggregate maximum rated heat input capacity of stationary fuel combustion units at a facility of less than 30 mmBtu/hr. This will also make it easy for operators to show compliance if audited/inspected by regulators.

Response: EPA agrees with the commenter that a screening tool would assist reporters in threshold determination. EPA plans to develop voluntary screening tools for each petroleum and natural gas industry segment. For more details, please see response to EPA-HQ-OAR-2009-0923-1011-30.

EPA has also in today's final rule established reporting thresholds for applicable emissions sources. For more details, please see Section II.E of the preamble to today's final rule.

8.2 ROLE OF STATES

Comment Number: EPA-HQ-OAR-2009-0923-1082-8
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment: Many of the states in which MidAmerican subsidiaries operate are already subject to state mandatory greenhouse gas reporting requirements; additional state and regional reporting requirements are, likewise, expected to be implemented within the next two years. The potential differences between state, regional and federal requirements relative to emission calculations and scope of coverage will create significant burdens on reporting entities. MidAmerican encourages EPA to coordinate with state and regional greenhouse gas reporting programs to develop a common platform for reporting emissions.

Response: In developing today's final rule, EPA had evaluated reporting programs at the state, regional, and federal levels. For the outcome of this evaluation, please see Sections A.4.a and A.4.b of the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027). The intended purpose of this evaluation was to identify whether there was already a suitable monitoring and reporting program in place of the requirements proposed under today's final rule and to locate emissions sources that are subject to reporting under various monitoring and reporting programs. In short, prior to release of the initial rule 40 CFR part 98, subpart W during 2009, EPA had already conducted significant research into and evaluation of state and other programs. In order to develop an inventory assessment based on a consistent set of assumptions, and control reporting burden, EPA was required to develop a platform that provided the best and most consistent data from all segments of the industry. EPA aknowledges that subpart W might not be identical to state and other data collection activities currently in place. Different reporting programs have different goals and objectives, and therefore different reporting requirements. Nevertheless, EPA has been working with states to ensure that data can be exchanged between EPA and state level reporting programs, thus facilitating the reduction of burden for reporters subject to multiple programs. Please see response to EPA-HQ-OAR-2009-0923-1015-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1155-9
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment: State and EPA Collaboration
Some states and jurisdictions may seek to coordinate their emissions reporting requirements with EPA's data collection effort. We support effective collaboration between EPA and the states, and encourage EPA to continue working cooperatively with WCI and individual states to enable effective coordination to ensure broad public access to the most rigorous emissions data available.

Response: EPA appreciates this comment, and has worked to coordinate with states, recognizing that different programs have different goals. EPA has discussed subpart W with states, and entities representing multiple states on data exchange, and will continue to work with states so that the value of the MRR program can be utilized by states as best possible.

8.3 ENFORCEMENT

Comment Number: EPA-HQ-OAR-2009-0923-1045-9
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon
Comment: Penalties for Finding Gas Leaks

Some of our customers have confidentially expressed concern that the use of OGI equipment could result in severe penalties since it is highly likely that the technology will detect gas leaks that would never be identified with OVA or TVA technology. Through our field work and training activities, we note that large leaks can occur over the course of time in natural gas and petroleum systems through no negligence of the operator. To address concerns over the compliance risks created by OGI requirements in Subpart W, EPA could consider amending existing federal regulations (such as New Source Performance Standards for VOCs) to allow a "grace period" for the correction of newly detected leaks at a facility that begins using OGI technology. Texas has adopted this approach, in a bill that will take effect at the end of this month.[83] This bill encouraged the adoption of OGI technology in a way that avoided unnecessary resistance from the petroleum industry.

Response: EPA has considered comments received regarding monitoring methods in April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002). In today's final rule, EPA is permitting the use of alternative methods to OGI equipment for detection of equipment leaks for certain emissions sources. For further elaboration on this topic, please see Section II.E in the preamble of today's final rule. Amendment of New Source Performance Standards (NSPS) or other regulations is beyond the scope of this rulemaking along with enforcement response which is a case-by-case decision based upon a particular set of facts and circumstances. In general, EPA attempts wherever possible to coordinate across rulemakings and programs.

Comment Number: EPA-HQ-OAR-2009-0923-1300-3
Organization: Texas Oil and Gas Association
Commenter: Deb Hastings

Comment: Implement a phased approach of the rule over a period of several years.

Response: EPA has reviewed the comment and disagrees that a phased approach to the implementation of today's final rule is required. For further details, please see response to EPA-HQ-OAR-2009-0923-1100-1, and a discussion of Best Available Monitoring methods in Section II.F in the preamble of today's final rule.

[83] House Bill (HB) 1526 of the 80th Legislature (2007), codified in Texas Health and Safety Code (THSC), §382.401, and in Texas Water Code, §5.752(2).

VOLUME 9: LEGAL ISSUES

9.0 LEGAL ISSUES

Comment Number: EPA-HQ-OAR-2009-0923-1024-16
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Responsibility for Reporting From Onshore Production Facilities. The proposed Subpart W overlooks significant complications associated with determining reporting responsibility for onshore production wells. Onshore production wells have extraordinarily diverse ownership and operating arrangements. A single well can be owned by one entity, be operated by another entity, lease portable equipment from a third entity, and have that portable equipment operated by yet another entity. In these situations, the entities that directly operate certain equipment are in the best position to gather emissions data for that equipment, whereas other entities working at the same well site have limited ability to verify that data. Yet the proposed rule places the burden of reporting entirely on the owner of the well or the holder of the operating permit.[84]

Kinder Morgan's operations place it in the position of being the owner of production wells, lessor of equipment, lessee of equipment, and contract operator of production equipment. With so many parties involved in reporting emissions from production equipment, Kinder Morgan is concerned that it could be liable under the Mandatory Reporting Rule even when it has taken all reasonable efforts for emissions information is properly reported to EPA. Thus, Kinder Morgan respectfully requests that EPA provide the following clarification and safeguards with respect to reporting responsibility in the onshore production sector:

a. Allow reasonable reliance on operators. Kinder Morgan is concerned that in cases where it is responsible for reporting emissions from a particular well, and must therefore collect emissions data from other entities operating equipment at that well, it could be held liable for non-obvious errors or omissions committed by those other entities. The Mandatory Reporting Rule should allow owners and permit-holders who are reporters to reasonably rely on data supplied by operating companies associated with the production well. This "safe harbor" would not, of course, apply where reliance is unreasonable, such as when the reporting entity knows that data are erroneous or false.

b. Disallow "vicarious liability" for errors committed by reporting entity. Kinder Morgan is also concerned that it may be held liable for errors or omissions committed by a reporting entity in situations where Kinder Morgan is merely providing data to the actual owner or holder of the operating permit at the well. EPA should clarify that an entity that provides properly collected emissions data to a reporting entity will not be held liable if that reporting entity subsequently commits an error or omission in reporting that data to EPA.

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[84] Proposed Subpart W, 75 Fed. Reg. at 18,614.

Response: EPA disagrees that Subpart W overlooks significant complications associated with determining reporting responsibility for onshore production wells. The Agency has determined that well owners or operators have control over rented, leased and contracted equipment and services through the language in contracts, leases or other arrangements and while these may require changes, ultimately the owner or operator is in the strongest position to obtain necessary data.

The owner or operator through their designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final Rule. The DR may provide in contracts, leases, or other agreements with third parties that true, accurate, and correct reporting information must be provided to the DR in a timely fashion. If the third party fails to provide timely, true, accurate, or correct information to the DR, then the DR has recourse contractually, or otherwise, on the third party. While the DR or his delegates may need to acquire necessary reporting information from a third party, the DR must make the appropriate inquiries and certification when reporting; ultimate responsibility rests on him or her. Please see Section II.F.5 of the preamble to today's final rule for a discussion of the designated representative's responsibilities along with Section 98.4 of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98).

The DR provisions are crafted similarly to the provisions of the Acid Rain Program (ARP), 40 CFR Part 72, and EPA has found that this approach provides a high degree of both data quality and consistency and accountability. Similar comments were made about the data coming from multiple owners and operators and the concerns about the certification of those data upon promulgation of the ARP and the 2009 final GHG reporting rule to which EPA responded.
In recognition of the potential need to adjust contracts, leases, or agreements, additional flexibility has been provided in today's final Rule to allow facilities to utilize best available monitoring methods for a limited period. For further details, please refer to Section II.F of the preamble in today's final rule. Moreover, to reduce burden, EPA has made provisions in today's final rule to require external combustion equipment; that have a rated heat capacity less than or equal to 5 mmBtu/hr to report equipment count by type; equipment above the threshold have to report emissions using monitoring methods. See Section II.E of the preamble in today's final rule for more information.

9.1 STATUTORY AUTHORITY

Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act
The following comments have been summarized to provide a common response;
Comment Number: EPA-HQ-OAR-2009-0923-1005-1
Organization: Independent Petroleum Association of America
Commenter: Lee Fuller

Comment Number: EPA-HQ-OAR-2009-0923-1011-26
Organization: El Paso Corporation
Commenter: Fiji George

Comment Number: EPA-HQ-OAR-2009-0923-1011-55
Organization: El Paso Corporation
Commenter: Fiji George

Comment Number: EPA-HQ-OAR-2009-0923-1011-58
Organization: El Paso Corporation
Commenter: Fiji George

Comment Number: EPA-HQ-OAR-2009-0923-1196-1
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

Comment Summary Text:
Commenters contend that EPA's authority to require GHG reporting stems exclusively from the Consolidated Appropriations Act, 2008, that appropriations bills do not provide broad and enduring authority for agencies to create new programs, are time limited, and create funding and policy actions that cannot extend beyond the scope of the direction in the bill.
Some commenters also believe that the Appropriations Act upon which the rule is based violates the separation of powers doctrine. As the statutory language of the Appropriations Act "does not, in its own terms, indicate what authority EPA is to invoke in order to require mandatory emissions reporting of greenhouse gases or otherwise indicate a policy purpose for this endeavor," Congress has asked EPA to establish a "reporting program despite Congress's unwillingness to date to itself enact a comprehensive GHG reporting and control regime. By failing to delineate the policy behind, and boundaries of, this delegated authority, the Appropriations Act violates the doctrine. Congress cannot delegate to an administrative agency Congress' law-making power or the power to exercise the discretion to modify a statute or power to add parties or acts to those punishable under the statute.

Even were EPA's position that the rule is authorized by section 114 of the CAA correct, they claim that the Subpart W proposal is in excess of EPA's statutory authority under CAA Section 114, fails to meet the standard of reasonableness applicable to requests for information under Section 114, would fail to meet the arbitrary and capricious standard of review if challenged, and EPA has exceeded its statutory authority under the Clean Air Act. They further claim that

Section 114 is the same section that authorizes EPA to issue administrative subpoenas to individual companies to collect information (also known as Section 114 requests). To be valid under Article 4 of the Constitution, subpoenas must be reasonable, relevant to the purpose, not overly broad or unreasonably disruptive, and not unreasonably burdensome, and the recipient is entitled to a finding as to whether EPA must pay the costs for responding to a burdensome subpoena. The subpart they say fails to meet that standard.

They further claim that the rule lacks a reasonable relationship between the express statutory purpose of collecting data reasonably necessary to inform GHG policy and the detailed and onerous monitoring provisions it proposes to impose on oil and natural gas systems. In addition, the rule is not supported by sound reasoning; fails to give reasonable consideration to important aspects of the problem, including the effects and costs of the choices it proposes to make, and fails to consider substantial arguments and alternative solutions.

Because GHGs are not yet subject to Section 110, 111, or 112, they also assert that Section 114 does not authorize EPA to promulgate the monitoring and reporting requirements of the proposed rule. Section 114 can only be used for regulated pollutants and provides authority for EPA to seek information for "carrying out any provision of this chapter." CO2 is not, however, subject to this "chapter." The term "chapter" means Chapter 85 of Title 42, i.e. the Clean Air Act Although the U.S. Supreme Court decided in *Massachusetts v. EPA,* 549 U.S. 497 (2007) that CO2 is an "air pollutant," until EPA makes a final endangerment finding and a control requirement is established under the Act, CO2 is not a "pollutant subject to the Act" and thereby not a "pollutant subject to the Chapter." Nor can EPA rely on its authority to do studies and investigations under Section 103 of the CAA to bootstrap into authority under Section 114 for the proposed rule. Section 103 does not mention the words "monitoring" or "reporting," only words such as "studies," "surveys," "investigations," and similar discrete, one-time or time-limited activities. When applied to the CAA, the rule of statutory construction, *ejusdem generis*, indicates that EPA's statutory authority is limited. Section 821 of Public Law 101-549, expressly authorizes EPA to require monitoring and reporting for CO2 on certain electric generating units. EPA's authority under Section 821 is limited, however, to certain power generating units subject to the provisions of the Acid Rain program. If EPA had the authority it now claims to have under Section 114 (bootstrapped by Section 103), it would have been unnecessary for Congress to enact Section 821 to establish ongoing CO2 monitoring and reporting requirements for power generating units, not to mention the monitoring requirements in Section 112, Title IV, and Title VI of the CAA, among others. A canon of statutory construction is that one section of an Act should not be read so as to usurp or make another section superfluous.

One commenter claims that use of Section 114 as the basis for the rule runs counter to its longstanding use of the section in the past which as been limited to issuing Information Collection Requests ("ICRs") and that ICRs are limited to collecting data from specific sources over a discrete period of time. Section 114 has not previously been used to justify an essentially economy-wide, permanent rule that requires all affected sources to submit new data annually on an ongoing basis and imposes new monitoring and measurement processes to collect such data. EPA's claims that it "has the authority to require all persons whom the Administrator believes 'may have necessary information' on emissions to report to the agency under CAA Section 114" and that the "reporting requirement may even extend to persons not otherwise subject to CAA requirements" is a capricious extension of the legislative intent of the Clean Air Act. Specifically, the Act has a list of entities under the jurisdiction of the CAA. To assume that it also applies to all petroleum and natural gas facilities operators based on an Administrator's subjective beliefs will result in arbitrary bureaucratic requirements to report under this rule

Summary Response: Regarding the EPA's legal authority to establish reporting requirements, the Appropriations Act as exclusive authority, Appropriations Act as violating the separation of powers doctrine, lack of a reasonable relationship between express statutory purpose and monitoring requirements, relationship between Section 114 and Sections 103, 110, 111 and 112, and 821 please see the Section II.Q, Summary of Comments and Responses on Statutory Authority, of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble, Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR and the response in Section I.C, Legal Authority, of the preamble to today's final rule. Also see [Volume 10, Cost and Economic Impacts of the rule] and preamble Section III respecting effects and costs of the choices proposed and alternative solutions generally. The argument that Section 114 is EPA's subpoena power is incorrect. The Agency's authority to issue subpoenas is in Section 307(a) and an attempt to engraft limitations of authority under Section 114 by mischaracterization as a subpoena authority is misfounded. Nevertheless, EPA's exercise of its authority under 114 is reasonable, relevant to the purpose, not overly broad nor unreasonably disruptive. See, Volume 9. Some burden in response to Agency inquiries in furtherance of its legitimate interests is not unreasonable.

Similarly, commenter confuses Section 114 and ICR requirements under the Paperwork Reduction Act, 44 U.S.C. 3501, et seq. EPA has issued an ICR for this rulemaking, has been assigned an EPA ICR number by OMB and has fully complied with PRA requirements. See, preamble Section IV.B See also, Volume 9 explaining that while it might be generally true that EPA has used its information gathering authority in a more targeted manner, nothing in Section 114 precludes this broader, yet still targeted rulemaking.

The claim that the Subpart W proposal is in excess of EPA's statutory authority under CAA 114, fails to meet the standard of reasonableness applicable to requests for information under Section 114, would fail to meet the arbitrary and capricious standard of review if challenged, and that EPA has exceeded its statutory authority under the Clean Air Act is conclusory and is not otherwise specifically supported by the commenter. Without more, EPA cannot directly respond other than to refer commenter to its position as its authority to use and to the reasonableness of using Section 114 as a basis for the rule as set forth in Volume 9. Similarly, the claim that EPA's exercise of its authority under Section 114 to include all petroleum and natural gas facilities operators is a capricious extension of legislative intent a only a conclusion on the commenter's part without supporting rationale to which response cannot be formulated.

As referenced above and explained in Vol. 9, Section 114 can apply to pollutants even though they might not be subject to regulation. Moreover, we note that EPA has taken final action that, as of January 2, 2011, makes the air pollutant comprised of the mix of six greenhouse gases subject to regulation under the Act. See, e.g., Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs; Final Rule, 75 FR

17004 (April 2, 2010) (explaining that greenhouse gases would become subject to regulation on the "takes effect" date of the Light Duty Vehicle Rule (Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule, 75 FR 31514) which was published on May 7, 2010.

Comment Number: EPA-HQ-OAR-2009-0923-1044-5
Organization: Colorado Department of Public Health and Environment
Commenter: Kirsten King

Comment Excerpt Text:
Disregards local agency, state or national boundaries, requiring emission sources to report aggregated emissions per basin, which may involve multiple local, state and national authorities.

Response: The GHG Reporting Program was established to collect data on national levels of greenhouse gas emissions by different sectors of the economy. For further information, please see the preamble of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), Section I.E and the response to comment EPA-HQ-OAR-2009-0923-1044-1 for further information. It is not possible to match every local or state boundary and still manage reporting under a reasonable facility definition that applies to all operators across the country. Please see response to EPA-HQ-OAR-2009-0923-1015-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-10
Commenter: Karin Ritter
Organization: American Petroleum Institute, Karin Ritter

EPA Lacks the Legal Authority for the Reporting Rule and Proposed Subpart W
EPA asserts that it developed the proposed Subpart W reporting requirements based on existing authority under Clean Air Act ("CAA") Section 114. See 75 Fed. Reg. 18,610. EPA, however, is over-reaching this authority, which does not authorize it to require the proposed indefinite and sweeping monitoring, recordkeeping, and reporting from the facilities covered by proposed Subpart W, regarding emissions with a currently uncertain regulatory status. At a minimum, none of EPA's stated purposes for the data justify the frequency and duration of the reporting requirements, or the imposition of burdensome new measurement protocols and the installation of extensive and expensive instrumentation. Further, EPA already has in its possession and continues to collect detailed GHG emissions inventory data that is sufficient to meet the stated purposes the Agency asserts underlie the proposed rule.

i. EPA's Interpretation of Its Section 114 Authority is Overly Broad
In the preamble to proposed Subpart W, EPA suggests it is appropriate to gather information required under the proposed rules because the information may be relevant to EPA implementation of a variety of CAA provisions. The Agency asserts that CAA section 114 "provides EPA broad authority to require the information proposed to be gathered by [the rules] because such data would inform and are relevant to EPA's carrying out a wide variety of CAA provisions." 75 Fed. Reg. 18,610. In the proposed Subpart W, EPA does not specify any particular purpose of CAA provisions for which it needs this information. The Agency merely

indicates that it is “comprehensively considering how to address climate change under the CAA, including both regulatory and non-regulatory options.” Id. at 18,611.

To begin, these generalized suppositions as to how the information might be used at some indeterminate time in the future provide wholly inadequate justification for an information request of the size, scope, and duration that EPA has proposed. EPA has a fundamental obligation to assert a rational basis for implementing its authority under Section 114, which includes in this case a particularized explanation of the reasons EPA actually, currently needs this information (versus a “wish list” of programs and policies that might be “informed” by gathering this information). In short, the proposal provides no clear, specific, and ascertainable explanation of why this information is needed and how it will be used and, thus, the rule stands to be an unreasonable and arbitrary exercise of Section 114 authority.

Moreover, the agency’s reading of its authority under Section 114 is overly broad and would improperly render meaningless the limitations in this provision. EPA emphasizes that information may be required under Section 114 for purposes of “carrying out any provision” of the Act. However, Section 114 has traditionally been limited to discrete information requests from particular emission sources, and EPA’s use of this provision for an ongoing reporting program for entire sectors of the economy is unprecedented.

Section 114 must be read in light of the entire statute, which makes clear that the data collection it authorizes is limited to only certain persons that are subject to the Act’s requirements. 42 U.S.C. Section 7414(a)(1) (limiting Section 114 applicability to “any person who owns or operates any emission source, who manufactures emission control equipment or process equipment, who the Administrator believes may have information necessary for the purposes set forth in this subsection, or who is subject to any requirement of this chapter (except a provision of subchapter II . . .)”). The applicability of Section 114 is thus limited to entities who own or operate an emission source or who are subject to regulation under the CAA for a given air pollutant. EPA’s attempt to collect data under Section 114 from persons who are not owners or operators of an emission source or who are not subject to regulation under the CAA exceeds Section 114’s authority and is improper. It is a fundamental rule of statutory construction that statutes should not be interpreted in a manner so as to make any phrase redundant. See, e.g., Gustafson v. Alloyd Co., Inc., 513 U.S. 561, 574 (1995) (“the Court will avoid a reading which renders some words altogether redundant”); Zimmerman v. Cambridge Credit Counseling Corp., 409 F.3d 473, 476 (1st Cir. 2005) (“no construction should be adopted which would render statutory words or phrases meaningless, redundant, or superfluous.”); U.S. v. Hovsepian, 359 F.3d 1144, 1160 (9th Cir. 2004) (“We interpret statutes so as to avoid making any phrase meaningless or unnecessary.”). EPA’s interpretation of Section 114 ignores and violates this well established canon by requiring indefinite data collection from any person based on the vague stated purpose of “carrying out any provision” of the Act. EPA cannot expand such authority beyond the express limitations of Section 114, and permit that single phrase to swallow the express limitations of the entire rule.

ii. The 2008 Appropriations Act Does Not Provide Legal Authority for the Rule

Clearly, EPA’s decision to propose Subpart W is motivated by the 2008 Consolidated Appropriations Act, signed into law on December 26, 2007. Consolidated Appropriations Act, 2008, P.L. 110-161, 121 Stat. 1844, 2128 (2008) ("Appropriations Act"). This Act authorized one-time funding "for activities to develop and publish a draft rule not later than 9 months after the date of enactment of this Act, and a final rule not later than 18 months after the date of enactment of this Act, to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States." Id. The straightforward point of the appropriations bill provision is to have EPA administer the collection of data; Congress did not draw any connection (as EPA attempts to do in its preambles to the two proposed rules) to carrying out any aspect of the CAA. Nor did the Appropriations Act provide EPA any new authority under the CAA to promulgate mandatory GHG reporting rules. Therefore, EPA's reliance on Section 114 is misplaced because, as explained above, these Sections may only be invoked for specified purposes under the CAA. General information gathering pursuant to the appropriations language is not within the scope of authority conferred by Section 114.

Moreover, the narrowly prescribed activity funded by the Appropriations Act necessarily constrains the scope of EPA's information gathering under Section 114. First, given the limited funds authorized by Congress, it would be impossible to maintain the indefinite and overly expansive reporting program for all sources in the onshore and offshore petroleum and natural gas sectors proposed. Second, the Appropriations Act does not prescribe any enforcement authority. Because the CAA does not independently provide the authority for the proposed rule, it cannot be the basis for any enforcement action. Congressional grants of enforcement authority must be explicit. Cf. Marshall v. Gibson's Products, Inc. of Plano, 584 F.2d 668, 675 (5th Cir. 1978) ("Congress is cognizant of the need to set forth explicitly the authority of an administrator or agency to seek enforcement relief in federal court.").

Response: For a response to this comment, please see EPA's Response to Public Comments, Volume No. 9, Legal Issues, October 30, 2009., and II.Q of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), as well as Section II.F of the preamble to today's final rule.

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Topic 2: Aggregation of Gathering and Boosting Systems with Processing Facilities
The following comments have been summarized to provide a common response;
Comment Number: EPA-HQ-OAR-2009-0923-1154-1
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-2
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-3
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-4
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer
Comment Number: EPA-HQ-OAR-2009-0923-1154-5
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer
Comment Number: EPA-HQ-OAR-2009-0923-1154-9
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-11
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer
Comment Number: EPA-HQ-OAR-2009-0923-1154-12
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-14
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-15
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-16
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-17
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-18
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-19
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-20
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1154-21
Organization: Latham & Watkins LLP
Commenter: Matthew C. Brewer

Comment Number: EPA-HQ-OAR-2009-0923-1080-30
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Summary Text:
The proposed GHG reporting rule's "super" source aggregation of the natural gas processing sector violates the Clean Air Act's "stationary source" requirements and otherwise is unlawful. Natural gas processing plants have been regulated under CAA programs as discrete "stationary sources" and have never been aggregated with gathering operations for purposes of applying thresholds and other requirements.
Commenter claims that the proposed GHG reporting rule is inconsistent with EPA's legal necessity findings for effective GHG regulation set forth in the tailoring rule. The doctrines of "absurd results", "administrative necessity" and "one-step-at-a-time" are intended to preserve a rational "major" and "minor" source distinction for GHGs so that the GHG permitting can apply to "major" sources as defined in the PSD program.

They also contend that the "stationary source" legal framework mandates a presumption against aggregation because the Clean Air Act regulates "sources" and the various Clean Air Act programs applying to stationary sources have either or both statutory and regulatory "source" definitions that depend upon three key elements, to wit: (1) "belong to same industrial group," are (2) "located on one or more contiguous or adjacent properties," and are (3) "under common control". "super" source aggregation is unprecedented in EPA's forty year history of regulating the natural gas process sector where typically the various regulations under the CAA define a facility as a group of emissions sources all located in a contiguous area and under the control of the same person (or persons under common control).

In further support, they claim that in the 1990 CAA amendments, Congress endorsed EPA's non-aggregation source approach to the natural gas industry by expressly codifying it under the Title III HAPs Program which approach, as expressed in Alabama Power Co. v. Costle, 636 F.2d 323 (DC Cir. 1979) over 30 years ago, and reflected in EPA's regulations and guidance, was expressly codified by Congress for the natural gas industry in Section 112(n)(4) of the Act.

Their position is further supported, they state, two recent pronouncements addressing aggregation in the natural gas industry: Memorandum from Assistant Administrator Gina McCarthy re: "Withdrawal of Source Determinations for Oil and Gas Industries" (September 22, 2009) and "Order Responding To Petitioners' Request That The Administrator Object To Issuance Of A State Operating Permit" (October 8, 2009) instructing the Colorado Department of Public Health and Environment, Air Pollution Control Division to reevaluate a decision it had made with respect to a natural gas compressor station owned by Kerr McGee Corporation. These positions indicate that only on a case-by-case basis may it be appropriate to aggregate emissions from wells or compressors in a gathering system and thus provide no basis for the proposed rule's "super" source aggregation of an entire gathering system with natural gas processing plant. In particular, the McCarthy memorandum reaffirmed that the three key factors -- same industrial group, contiguous or adjacent location, and common control -- apply on a case-by-case basis to determinations of whether aggregation of emissions in the natural gas industry are appropriate; thus aggregation of natural gas processing systems as proposed is inappropriate.

Section 114 allows information gathering to implement and enforce substantive regulatory provisions only, and therefore, does not provide a legal basis for EPA to impose a unique "source" definition that conflicts with its history of regulating the natural gas processing sector they argue. Specifically, Section 114 authorizes information gathering solely for the purpose of developing or assisting in the development of regulations under the provisions specifically enumerated in Section 114, enforcement of existing regulations or carrying out any other provision of the Act.

With respect to the Proposed Subpart W, Section 114 provides EPA no authority to implement "super" source aggregation for the natural gas processing sector independent of and in direct conflict with the regulatory history of the Act's application to the natural gas processing sector. Nor has EPA, they aver, provided any rational explanation as required by section 114 for how GHG emissions information gathered on a "super" source aggregation basis will support its implementation of GHG regulatory programs for the natural gas processing sector. Application of Subpart W's reporting requirements to the sector as defined in the rule as proposed is not reasonably limited in scope and time as required by various aspects of Section 114.

The proposed rule is "arbitrary and capricious" because epa's reference to materially different, non-clean air act reporting programs, such as DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations and the Climate Registry provides no as justification for "super" source aggregation commenter contends.

Finally, in support of its averment that the proposed natural gas processing facility definition is legally flawed, commenter believes that the approach is simply unfair and inequitable. In taking such an approach here, EPA would be setting a precedent that any industries that have a complex manufacturing and distribution chain could be required to aggregate all emissions associated with a product, including those from geographically distant facilities and emissions associated with the transport of materials among facilities. If this is not the case, then the application of the "super" source aggregation approach to only the natural gas processing sector is simply unfair. In particular, the requirement that the natural gas processing sector report fugitive emissions from gathering systems while not requiring similar reporting from the natural gas transmission sector is fundamentally inequitable.

Summary Response: As is clear from the submission, these comments are peculiar to and squarely relate to the onshore natural gas processing segment of subpart W and the inclusion of gathering operations in the source category segment. In today's final rule, EPA has revised the definition of the segment to eliminate reference to field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gather lines or compressors) as feed to the natural gas processing facilities as being a part of the processing facility, as well as reference to gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user being considered stand alone natural gas processing facilities. Therefore, while EPA does not agree with the positions taken in support of commenter's argument, because gathering operations relating to natural gas processing facilities are not included in the source category and the commenter's concern that EPA is unlawfully augmenting the source category by their inclusion is a moot point. As EPA interprets the comments, they are limited exclusively to the onshore natural gas processing segment making further response unnecessary. EPA may choose to cover emissions from this portion of the industry at a later time by further rulemaking or otherwise. With respect to the scope of EPA's authority under Section 114, see Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR.

9.1.1 SEGREGATE OFFSHORE ISSUES SEPARATELY

Comment Number: EPA-HQ-OAR-2009-0923-1155-13
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
OCS Authority

EPA is proposing to amend 40 CFR 98.2(a) so that the Final Mandatory GHG Reporting Rule applies to facilities located in the United States and the Outer Continental Shelf.

Additionally, EPA is proposing revisions to the definition of United States to clarify that it includes the territorial seas. This ensures that the facilities located offshore of the United States that are injecting CO2 into the sub-seabed for long-term containment will also be required to report data regarding GHG emissions. EPA writes:

"Together these changes make clear that the Mandatory GHG Reporting Rule applies to facilities on land, in the territorial seas, or on or under the Outer Continental Shelf, of the United States, and that otherwise meet the applicability criteria of the rule."[85]

EPA notes that its Clean Air Act (CAA) authority to collect emission information from certain offshore petroleum and natural gas platforms has been questioned:

"Some commenters argued that EPA does not have the authority to collect emissions information from offshore platforms located in areas of the Western Gulf because they are under the jurisdiction of the Department of the Interior. They cited, among other things, the Outer Continental Shelf Act, 43 U.S.C. 1334. Without opining on the accuracy of the commenter's

[85] Federal Register Vol. 75, No. 69, 18611.

summary of OCSLA or other law, we note that even the commenter describes these authorities as relating to the regulation of air emissions. Today's proposal does not regulate GHG emissions; rather it gathers information to inform EPA's evaluation of various CAA provisions. Moreover, EPA's authority under CAA Section 114 is broad, and extends to any person 'who the Administrator believes may have information necessary for the purposes' of carrying out CAA, even if that person is not subject to the CAA [emphasis added]."[86]

We support EPA's inclusion of OCS sources in Subpart W. We strongly agree with the EPA that it plainly has authority to collect emissions information from offshore oil and gas platforms.[87] As the agency states, "EPA's authority under [Clean Air Act] Section 114 is broad."[Id.] Indeed, that section gives EPA authority over "any person who owns or operates any emission source," including the power to establish monitoring systems, require equipment to be installed, and collect any "other information as the Administrator may reasonably require."[88] Nothing in the statute indicates this power stops at the beach, and such a limit would be entirely inconsistent with the provision's purpose of providing high quality emissions data to the public, as offshore platforms are a major pollution source.

EPA writes that some commenters, nonetheless, suggest that the Outer Continental Shelf Lands Act ("OCSLA"), 43 U.S.C. §§ 1331, somehow limits EPA's authority. These commenters have the law backwards. First of all, nothing in OCSLA purports to limit EPA's authority, so the commenters would have to argue that OCSLA implicitly repeals Section 114 authority over offshore activities – even though the statute does not contain a word of text doing so. That argument "runs foursquare into [the] presumption against implied repeals."[89] That "powerful" presumption states "that absent a clearly established congressional intention, repeals by implication are not favored. An implied repeal will only be found where provisions in two statutes are in irreconcilable conflict."[90] Nothing in OCSLA and Section 114 are irreconcilable, so the agency, rightly, must presume Congress did not silently strip its powers away. Indeed, OCSLA, if anything, reinforces EPA's authority. That statute explicitly extended the "laws and civil and political jurisdiction of the United States" to the Outer Continental Shelf, cementing the relevance of domestic environmental law to that region.[91] In doing so, Congress recognized that the shelf is:"a vital national resource reserve held by the Federal Government for the public," and which is "subject to environmental safeguards."[92] In fact, Congress even ordered the Secretary of the Interior, who oversees leasing programs in the region, to "cooperate with the relevant departments and agencies of the Federal Government" to enforce "environmental laws."[93] In

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[86] Federal Register Vol. 75, No. 69, 18611.

[87] See 75 Fed. Reg. at 18,611.

[88] 42 U.S.C. § 7414(a) (emphasis added).

[89] See National Ass'n of Home Builders v. Defenders of Wildlife, 551 U.S. 644, 665 (2007).

[90] Lockhart v. United States, 546 U.S. 142, 149 (2005).

[91] See 43 U.S.C. § 1333(a)(1).

[92] See 43 U.S.C. § 1332(3).

[93] See 43 U.S.C. § 1334(a).

short, there is no serious argument that EPA lacks authority for its actions. If anything, EPA would be remiss if it did not account for major offshore oil and gas emissions sources. Offshore petroleum and natural gas systems GHG emissions must be included in EPA's overall national assessment of "all sectors of the economy of the United States," as required. Thorough data is needed to develop a national policy that addresses GHG emissions as a whole, and not in a piece-meal fashion.

Response: EPA agrees with the commenter that it has jurisdiction to gather information from offshore facilities. *See also,* Response to EPA-HQ-OAR-2009-0923-1151-16.

Comment Number: EPA-HQ-OAR-2009-0923-1151-16
Organization: American Petroleum Institute
Commenter: Karin Ritter
<u>Comment Excerpt Text:</u>
D. Offshore Petroleum and Natural Gas Production Facilities in the Western Gulf of Mexico

i. EPA Authority Over the Western and Central Gulf of Mexico

Under the proposed Subpart W, offshore petroleum and natural gas production facilities located in both State administered waters and Mineral Management Services administered Federal waters would be obligated to report GHG emissions. The platforms in the Western and Central Gulf of Mexico should be excluded from the reporting rule because the MMS has jurisdiction for air emissions from facilities on the Outer Continental Shelf ("OCS").

Under the Outer Continental Shelf Lands Act ("OCSLA"), the Department of Interior ("DOI") has the authority to regulate air emissions on the OCS. U.S.C. Section 1334. In California v. Kleppe, the court held that the OCSLA's specific grant of jurisdiction to DOI precluded the application of Prevention of Significant Deterioration regulations to E&P facilities on the OCS. 604 F.2d 1187 (9th Cir. 1979). In so ruling, the court specifically rejected EPA's argument that dual jurisdiction over air pollution on the OCS existed between EPA and DOI.

After Kleppe, the 1990 Clear Air Act Amendments established the authority of EPA to regulate air pollution on the OCS from oil and gas exploration and production facilities (referred to as "OCS sources"), but as to the Gulf of Mexico, limited EPA's air pollution jurisdiction over OCS sources to the area of the Gulf of Mexico east of longitude 87 degrees and 30 minutes and confirmed DOI's air pollution jurisdiction to the area of the Gulf of Mexico west of longitude 87 degrees and 30 minutes ("Western and Central Gulf"). Air pollution from OCS activities, 42 U.S.C. Section 7627, provides as follows:

(a)(1) Applicable requirements for certain areas

Not later than 12 months after November 15, 1990, following consultation with the Secretary of the Interior and the Commandant of the United States Coast Guard, the Administrator, by rule, shall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States along the Pacific, Arctic and Atlantic Coasts, and along the United States Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes ("OCS sources”) to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of part C of subchapter I of this chapter. For such sources located within 25 miles of the seaward boundary of such States, such requirements shall be the same as would be applicable if the source were located in the corresponding onshore area, and shall include, but not be limited to, State and local requirements for emission controls, emission limitations, offsets, permitting, monitoring, testing, and reporting … The authority of this subsection shall supersede section 5(a)(8) of the Outer Continental Shelf Lands Act [43 U.S.C.A. Section 1334(a)(8)] but shall not repeal or modify any other Federal, State, or local authorities with respect to air quality…

(b) Requirements for other offshore areas

For portions of the United States Gulf Coast Outer Continental Shelf that are adjacent to the States not covered by subsection (a) of this section which are Texas, Louisiana, Mississippi, and Alabama, the Secretary shall consult with the Administrator to assure coordination of air pollution control regulation for Outer Continental Shelf emissions and emissions in adjacent onshore areas. Concurrently with this obligation, the Secretary shall complete within 3 years of November 15, 1990, a research study examining the impacts of emissions from Outer Continental Shelf activities in such areas that fail to meet the national ambient air quality standards for either ozone or nitrogen dioxide. Based on the results of this study, the Secretary shall consult with the Administrator and determine if any additional actions are necessary.

In proposed Subpart W, EPA has expressly stated that the CAA is the source of its authority for the proposed rule. Yet, there is no authority under the CAA for the collection of information with respect to geographic areas or industry segments over which EPA has no jurisdiction, such as the Western and Central Gulf. See 42 U.S.C. Section 7414(a) (enumerating authorized purposes for EPA’s seeking information from the regulated community). Instead of EPA jurisdiction over OCS sources in the Western and Central Gulf, under the CAA, the Secretary of DOI is merely required to consult with the Administrator of the EPA with respect to OCS emissions with regards to the Western and Central Gulf, not vice versa.

Congress has recognized that the Western and Central Gulf of Mexico is a unique national resource. In order to promote and regulate the expeditious and orderly development of this resource, Congress made a conscious decision to place the regulation of air emissions from OCS sources with DOI, an agency that has specialized expertise with regard to exploration and production activities and their effect on both the OCS and onshore environments. Under OCSLA, Congress has chosen DOI as the lead and exclusive agency for all aspects of air emissions in the Western and Central Gulf. EPA’s proposed rule undermines Congress’ delegation of this authority to DOI.

Finally, EPA cannot justify applying this proposed rule to the Western and Central Gulf by stating that it is under a directive to collect information from all industry segments. The general statement that emissions from all segments should be reviewed cannot be fairly interpreted as an expansion of jurisdiction where there previously was none. Nor can EPA justify this proposed rule by stating that “information collection” is not “regulation.” This issue was addressed in the Williams Companies v. FERC, 345 F.3d 91 (D.C. Cir. 2003). In Williams, the court found that the FERC could not require companies to submit certain information relating to pipeline transportation rates on OCS pipelines because Congress gave DOI (through OCSLA) authority to regulate open and non-discriminatory access to OCS pipelines.

As applied to OCS sources in the Western and Central Gulf, the proposed rule is beyond EPA authority, violates both the CAA and OCSLA (and possibly other federal statutes such as the Administrative Procedures Act, the Paperwork Reduction Act, etc.), and is unfair, overly burdensome and inefficient. For these reasons, the Western and Central Gulf should be excluded from the proposed rule.

Response:
The commenter did not respond directly to EPA's statements in the proposed rule regarding the agency's broad authority to collect information under section 114 of the CAA, including from sources in the Western Gulf. Moreover, these comments reflect a misunderstanding of the scope of EPA's authority under section 114 of the CAA. EPA's authority under CAA Section 114 is broad, and extends to any person ''who the Administrator believes may have information necessary for the purposes'' of carrying out the CAA, even if that person is not subject to the CAA. Indeed, by specifically authorizing EPA to collect information both from persons subject to any requirement of the CAA, *and* from any person who the Administrator believes may have necessary information, Congress intended that EPA could gather information from a person not otherwise subject to CAA requirements. Thus, any limitations that may apply to EPA's jurisdiction to restrict or otherwise control emissions of air pollutants from sources in the Western Gulf would not *ipso facto* also apply to EPA's ability to gather information from those sources.

Moreover, we do not read the case law as narrowly as commenter. *California v. Kleppe,* in which the Ninth Circuit found that OCSLA and the legislative history of 1978 Amendments to the OCSLA demonstrated that the Secretary of Interior had sole authority to promulgate air quality **regulations** for OCS sources, is not dispositive regarding EPA's information gathering authority.[94]

When the *Kleppe* case was litigated, the CAA did not give EPA any express authority over OCS. In that pre-1990 case questioning EPA's determination that construction of a floating offshore storage and treatment facility off the California coast was subject to NSR/PSD requirements and permitting, the *Kleppe* court reasoned that Congress had not made its intent clear with respect to EPA authority over OCS. There, it held that the 1978 Amendments to the OCSLA granted the Secretary of the Interior the "authority to *promulgate air quality regulations* for the OCS " which

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[94] The *Kleppe* decision clearly focuses solely on authority to regulate. Throughout, the Court addresses *regulations* for the control of air quality. (See, e.g., *Kleppe* 604 at 1195: "[t]he House report [on the 1978 OCSLA amendments] … was silent with respect to EPA jurisdiction over the OCS for control of air quality;" "[a]t that time the proposed air quality provisions were amended to specify that the Secretary would promulgate regulations;" "the Secretary was to 'solicit and give due consideration to the views of the Administrator of the Environmental Protection Agency in developing his regulations;" 1196: ""the statute itself also placed no apparent limits on the Secretary's regulatory authority over OCS air quality control." (Emphasis supplied.)

authority was not to be shared. *Kleppe*, 604 at 1187 (emphasis added). However, the decision says nothing about EPA's information gathering authority under CAA Section 114.
By contrast, Congressional intent regarding EPA's information collecting authority has been quite clear. Congress has consistently broadened EPA's authority to gather information, extending it to cover even persons not otherwise subject to the CAA. See, Vol. 9 Response to Comments, Legal Issues on the 2009 final MRR. ("Congress repeatedly broadened the scope of persons subject to 114 – first adding any person subject to the CAA in 1977, and then expanding it to include manufactures of control equipment and any person "who the Administrator believes may have information necessary for the purposes" of section 114. See H.R. Conf. Rep. 95-564, Aug. 3, 1977; P.L. 95-95, §§ 109(d)(3), 113, 305(d) (Aug. 7, 1977); P.L. 95-190, § 14(a)(22), (23) (Nov. 16, 1977); P.L. 101-549, §§ 302(c), 702(a), (b) (Nov. 15, 1990); see also CED's Inc. v. EPA, 745 F.2d 1092, 1097(7th Cir.), cert. denied, 471 U.S. 1015 (1984). Thus, section 114 is not limited to persons who own or operate an emission sources or are otherwise subject to regulation under the CAA.")

Moreover, Congress made its intentions clear with respect to EPA's authority over the OCS in the 1990 Amendments to the CAA when it added section 328, "OCS Air Pollution" to the CAA. Paragraph (b) of 328 addresses the Western and Central Gulf and states that, "the Secretary *shall consult* with the Administrator [of the EPA] to assure coordination of air pollution control regulation for Outer Continental Shelf emissions and emissions in adjacent onshore areas. Concurrently with this obligation, the Secretary shall complete within 3 years of enactment of this section a research study examining the impacts of emissions from Outer Continental Shelf activities in such areas[95] that fail to meet the [NAAQS] for either ozone or nitrogen dioxide. Based on the results of this study, the Secretary shall, consult with the Administrator, and determine if any additional actions are necessary." Prior to the 1990 amendments no such consultation was required under either the CAA or OCSLA. Instead, OCSLA simply required DOI to *cooperate* with EPA. 5 U.S.C. §1334(a).

The clear language of the 1990 Amendments indicates that Congress intended that the Secretary of Interior and Administrator of the EPA each have a role in the Western and Central Gulf. Indeed, commenter admits that EPA has at least a consultation role regarding sources in the Western Gulf, but then fails to address whether in fulfilling its role EPA could collect necessary information. Rather, it merely asserts that EPA has no authority at all to gather information from sources in the Western Gulf, regardless of whether related to this consultation role, demonstrating the flaws in their argument. Any limitation of the Agency's express authority to issue air quality regulations does not mean that it has *no* authority there.
Further, as pointed out by other commenters, [*see, e.g.*, EPA-HQ-OAR-2009-0923, 1155-13 and authorities cited therein] it would be unreasonable to interpret OCSLA to somehow implicitly repeal EPA's information gathering authority under Section 114 as it pertains to offshore activities. OCSLA contains no such language, while on the other hand, Congress was quite clear regarding EPA's broad information gathering authority. The argument, as they point out, "runs foursquare into [the] presumption against implied repeals," and implied appeals are not favored.

[95] "[Portions] of the United States Gulf Coast Outer Continental Shelf that are adjacent to the States not covered by subsection (a) of this section which are Texas, Louisiana, Mississippi, and Alabama…."

Only where provisions in two statutes are irreconcilable will an implied repeal be countenanced, and nothing in OCSLA and Section 114 are irreconcilable. As explained elsewhere, EPA has valid reasons for gathering this information, consistent with carrying out provisions of the CAA, and none of these interfere with or "undermine" DOI's authority under OCSLA. Significantly, even the *Kleppe* court acknowledged that the conference committee report on the 1978 OCSLA amendments stated that "it did not intend to affect 'whatever present authority the Environmental Protection Agency has in applying and enforcing the Clean Air Act.'" *Kleppe* 604 at 1196. [96]

Moreover, aside from the question of whether EPA can directly regulate emissions from sources in the Western and Central Gulf, EPA is not precluded from performing other tasks, like requesting air emissions information from such sources. This information gathering exercise is completely different than that struck down by the court in *Williams Companies v. Federal Energy Regulatory Commission*, 345 F. 3d 910 (D.C. Cir. 2003). There, FERC was trying to rely on the open-access provisions of OCLSA for its authority to gather information, and the court held that open-access provisions did not confer authority upon FERC to issue regulations. Here, EPA is not relying on OCSLA for its authority, but rather on the CAA, which, as discussed above and in Vol. 9, above, which unambiguously grants EPA broad authority to gather information for purposes of carrying out the CAA.[97]

Moreover, the information EPA is gathering under this rule from petroleum and natural gas systems, including those in the Western and Central Gulf, is consistent with the purposes of section 114, which include carrying out any provision of the CAA. EPA is comprehensively considering how to address climate change under the CAA, including both regulatory and nonregulatory options. The information from these and other offshore platforms will inform our analyses, including options applicable to emissions of any offshore platforms that EPA is authorized to regulate under the CAA.

9.2 CONFIDENTIAL BUSINESS INFORMATION (CBI)

Comment Number: EPA-HQ-OAR-2009-0923-1015-27
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
General Comments – Protection of Sensitive Business Information
On page 56358 of the Federal Register, EPA states they are, "collecting owner and operator information through the Certificate of Representation (40 CFR 98.4). At this time, EPA is not proposing to assign unique identifiers to the owners and operators because of the complexity of

[96] The relevant information gathering provisions of the CAA were in place in 1977. *See*, Vol. 9, above.

[97] Further, as pointed out above, monitoring and reporting rules are not "regulation." *See* also, Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs; Final Rule, 75 FR 17004 (April 2, 2010)

ownership structures (including percentage shares of owners, subsidiaries, holding companies, and limited liability partnerships) that can be used in the multiplicity of industrial sectors required to report emission data under this rule."

Many PAW members are privately held companies, and consider percentage of shares of owners confidential business information.

Response: Today's final rule does not address whether data reported under subpart W will be released to the public or will be treated as confidential business information (CBI). Please see Section II.B of the preamble to today's final rule for further information regarding the treatment of CBI and the Proposed Confidentiality Determination for the Mandatory Greenhouse Gas Reporting Rule and Proposed Rule Amendment Specifying Procedures for Handling Part 98 Data (EPA-HQ-OAR-2009-0924-001) along with the Proposed Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule Supplemental Proposal (EPA-HQ-OAR-2009-0924-008) which are located at http://www.epa.gov/climatechange/emissions/CBI.html#proposal.
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Comment Number: EPA-HQ-OAR-2009-0923-1039-23
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Optical Gas Imaging Instrument Video Records are Business Confidential and Should Not Be Available via a FOIA Request

For the optical imaging leak screening, the preamble indicates that video records are required and §98.237(b) specifies that the operator must retain, "Results of all emissions detected and measurements." EPA should clarify in the rule text whether video records are required for compliance with §98.237(b).

INGAA understands that EPA still plans to propose amendments to Subpart A to address Confidential Business Information (CBI). If that action is completed on a timely basis, it should identify leak survey video records as CBI. If the Subpart A amendments to address CBI are not finalized prior to Subpart W promulgation, this issue should be addressed in the Subpart W Final Rule.

EPA discusses the CBI rulemaking in the October 2009 Final Rule for GHG Mandatory Reporting. At 74 FR 56287, EPA indicates,

"Through a notice and comment process, we will establish those data elements that are ‘‘emissions data’’ and therefore will not be afforded the protections of CBI. As part of that exercise, in response to requests provided in comments, we may identify classes of information that are not emissions data, and are CBI."

Due to security concerns associated with national industrial operations and energy infrastructure, it is imperative that facility video records from optical camera leak surveys are afforded protection as CBI. Optical camera video records should be considered CBI and should not be available through a Freedom of Information Act (FOIA) request.

Response: Today's final rule has been revised, EPA does not require retention of a video recording of the leak detection using optical imaging cameras. Hence, CBI is not relevant in this case.

Comment Number: EPA-HQ-OAR-2009-0923-1060-15
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Protection of Sensitive Business Information

On page 56358 of the Federal Register, EPA states they are, "collecting owner and operator information through the Certificate of Representation (40 CFR 98.4). At this time, EPA is not proposing to assign unique identifiers to the owners and operators because of the complexity of ownership structures (including percentage shares of owners, subsidiaries, holding companies, and limited liability partnerships) that can be used in the multiplicity of industrial sectors required to report emission data under this rule."

Yates is a privately held company, and considers percentage of shares of owners confidential business information.

Response: Regarding the protection of sensitive business information, please see the response to EPA-HQ-OAR-2009-0923-1015-27.

9.3 RELATIONSHIP TO OTHER CLEAN AIR ACT (CAA) PROGRAMS

Comment Number: EPA-HQ-OAR-2009-0923-2345-3
Organization: DFW Regional Concerned Citizens (DFWRCC),
Commenter: Faith Chatham

Commenter Type: Industry - oil and gas Without an actual measure to determine the actual emissions and testing to determine the composition of the emissions per facility (apparatus or site), there is no way to effectively enforce these rules. Currently each operator can say that elevated readings are just part of their normal allowed (or calculated (estimated or guesstimated) 25 tons per year of VOCs.

I live in Arlington, Texas. Since 2006 `the Arlington City Council and Texas Railroad Commission has permitted 187 gas wells with accompanying pipelines, storage tanks, and compression stations. The City of Arlington has 39 completed natural gas drilling applications. Numerous others have already been heard by the P&Z Commission but have not been heard by the City Council. Two of these applications currently being considered by the City Council are for drill sites and Natural Gas pipelines at two sites which are each within three blocks of the Cowboy Stadium which draws up to 100,000 fans. One is between the stadium and the only ER/Trauma center in this part of town. If an accident occurs at a well permitted at that site when there are events at the stadium, 350,000 people could easily be harmed. My estimates include pupils at a school for the deaf one block from the proposed drill site, patients at a kidney diolisis center or in a medical office building on two sides of the site, shoppers at the Lincoln Square Shopping Center in the next block from the site, people driving on I-30 to the immediate north of the site, residents in a nursing home one block west of the site, and residents in apartments and homes around the site. When the stadium was built an increase in automobile traffic is believed to have impacted air quality yet no baseline testing has been done to measure air quality when there are no events at the stadium and none has been done when the stadium has capacity crowds to compare to see if there is a significant difference. Without combining the emissions already in the neighborhood with projected emissions from a gas drilling/production/storage/compression or transfer facility, it is impossible to protect the health of those near those sites. Cities should be limited in permitting new facilities when they are out of air quality attainment levels. Vapor Recovery Systems should be mandated on all O&G tanks in areas within 3000 feet of doctor's offices, medical clinics, hospitals, parks, schools, day cares, homes and churches. Citizens who own or rent homes or apartments or lease business space should be notified if that space is within 3000 feet of a proposed O&G drill, storage, transfer or compression site. Notification should be for a wider footprint than the mere set-back requirements from adjacent building. These requirements should be enacted for people in every state. States and local municipalities should be restricted from issuing new O&G permits in areas where the emissions from already existing facilities are 1. calculated not accurately measured 2 exceed a cumulate level measured in tons per year per community set by the EPA utilizing sound science which protects the health of unborn babies, young children, pregnant women and medically vulnerable people. Oil and Gas drilling should be restricted adjacent to roads and or intersections with traffic counts exceeding a level set by the EPA based on sound science showing impairment to the common good by a potential accident at that site.

Oil and Gas permits should have to demonstrate that an accident at that site impacting the geographic area common by accidents at similar sites will not result in loss of life to thousands of people within the mile or half mile (as set by EPA based on sound science) footprint of the well or facility. When permits are issued at high density population sites, the city and operator should be required to submit a disaster plan including evacuation plans for venues attracting large numbers of people, for medical facilities and schools and residences for the handicapped or elderly.

The route of pipeline serving a O&G well site should be disclosed prior to permitting of the well to residents and business persons living or renting space within 3000 feet of the drill site, pipeline, storage or compression station. Renters and business owners and patrons of businesses should be considered when permits are considered instead of just property owners who sign mineral leases.

There should be continuous monitoring of air quality by O&G sites within 1500 feet from day care centers, hospitals, nursing homes, medical office buildings, shopping centers, schools, churches, parks, playgrounds, stadiums and residence and along natural gas pipelines with unodorized gas running in residential neighborhoods and by business or educational establishments where people regularly.

In Arlington if every wellhead permitted since 2006 is allowed 25 tons of VOCs per well head and "qualifying apparatus" just the 187 new wellheads already permitted allows them to emit nearly 5000 tons of VOCs a year. That is without consideration of storage tanks and compression stations and emissions from pipelines! With addition of venues which attract thousands of cars into the region and growth in residential and visitor traffic to the city, we cannot continue to allow 25 tons per apparatus or site of VOCs. There is no requirement that their calculations are actually measured. There is no way to effectively enforce the proposed rule unless you mandate devices to measure the VOCs. Companies might be allowed to utilized actual measurements on sites until there is a demonstration that the amount of their VOCs and the content of the VOCs is not harming the people's health or contributing to greenhouse gas in levels which when combined with emissions industries and practices in the area do not create a cumulative negative effect on human health and the environment.

Water samples, soil samples, and air samples and blood samples from a sample of residents in the area should be taken before permits are issued and compared periodically to provide data so that future decisions can be made regarding the real impact of such activities on human health. Similar studies should be made on flora and wildlife in the area. It would not be necessary to do this at every well site but it should be mandated in communities which have sharp escalation in the number of sites permitted in a few years such as Arlington, Fort Worth and other places in the Barnett Shale where they permit over 50 new sites a year.

Response: EPA has reviewed this comment, and concludes it is out of scope with today's final rule and The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98).

Comment Number: EPA-HQ-OAR-2009-0923-1010-1
Organization: Oklahoma Independent Petroleum Association
Commenter: Burckhalter

<u>Comment Excerpt Text:</u>
EPA should not change the definition of "facility" in order to aggregate crude oil and natural gas production sites.

EPA states that most small businesses will fall under the 25,000 $mtCO_2e$ threshold and would not be required to report GHG emissions; however, by requiring an operator to report emissions from all of their crude oil and natural gas production sites within a basin as a "facility" will subject many small businesses to the proposed GHG data collection and reporting requirements which is directly opposite of EPA's stated goal. The proposed aggregation of crude oil and natural gas production sites is contrary to the Clean Air Act definition of a "facility" and to subsequent interpretations that industry and regulators understand. Additionally, EPA is not applying a new definition of facility and aggregating sites from other industry sectors in the same fashion (with the exception of Subpart RR). By aggregating sites, the impacts to small crude oil and natural gas businesses will be significant.

Response: EPA does not agree with the commenter. The commenter does not provide any details on its claim that the rule "will subject many small businesses to the proposed GHG data collection and reporting requirements". EPA through its analysis has in fact determined that the impact on small businesses will be insignificant. Please see response to EPA-HQ-OAR-2009-0923-1005-7 and Section 5.2 of the EIA for further details.

EPA also does not agree that the onshore facility definition is contrary to the CAA requirements. Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and the response to EPA-HQ-OAR-2009-0923-1044-1 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1044-1
Organization: Colorado Department of Public Health and Environment
Commenter: Kirsten King

Comment Excerpt Text:
However, the State disagrees with the basis for aggregating oil and gas facilities for greenhouse gas reporting largely because it creates additional inconsistencies between the MRR and Prevention of Significant Deterioration (PSD) and Title V Operating Permit (Title V) Programs under the Clean Air Act beyond the existing discrepancies between the rules (i.e. actual vs. potential to emit, metric vs. short tons, etc.). Specifically, it argues that the rule departs from the "traditional" source definition under PSD and Title V and places more emphasis on control of equipment rather than operation or ownership, that it addresses emissions outside of the PSD and Title V permitting programs' purview and that the facility definition based upon a hydrocarbon basin disregards local, state or national boundaries.

Response: As we pointed out in Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR, to which the commenter is referred, there are myriad reasons supporting EPA's authority and need to gather information under the rule. In the Advance Notice of Proposed Rulemaking Regulating Greenhouse Gas Emissions under the Clean Air Act, 74 Fed. Reg. 44354 (July 30, 2008) (ANPR) we articulated the various CAA provisions under which information gathered about GHGs would be relevant and useful. It is reasonable for the Agency to collect GHG emissions information from petroleum and natural gas systems to inform the Agency's regulation and understanding of GHG emissions under any number of those programs as well as to carry out its Congressional mandate. The PSD and Title V programs are only two such relevant programs and it is not appropriate to compare data collection under the MRR to those programs. The MRR is unique, and its purpose is not limited to either of those programs. That said, information gathered through this rulemaking will be valuable in determining how best to administer the PSD and Title V programs, but they are not the only programs for which information collected under the MRR might be used. As we have pointed out previously, this includes the National Ambient Air Quality Standard and State Implementation Plan programs under 1-7-110 of the Act, New Source Performance Standards (NSPS) under 111, National Emission Standards for Hazardous Air Pollutants (NESHAP or MACT) under section 112. Additionally, as has been pointed out elsewhere by other commenters, the structure of the CAA supports EPA's position. Its authority under Section 114 of the CAA as the basis for the proposed GHG reporting rule is completely independent from EPA's authority for other CAA programs, for example, from EPA's CAA NSR authority, including CAA Sections 160-169 and 171-193. As such, EPA regulations promulgated under these distinct provisions in Section 114 cannot and should not impact the other CAA programs and vice versa. Therefore, EPA's definition of "facility" for purposes of the proposed Subpart W in no way impacts the "facility" definition for similar sources under the NSR program or other existing CAA programs.

Additionally, information collected from the petroleum and natural gas systems sector is relevant to the Agency's understanding of GHG emissions, particularly inasmuch as the sector, by industry, generates the second largest amount of human-made greenhouse gas emissions in the United States. Further, as explained in the preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) and accompanying Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923), because of the unique nature of petroleum and natural gas production facilities, it is reasonable and appropriate in this rule to define the facility based on the hydrogeologic basin and equipment owned or operated by the entity holding permits in that basin. The physical boundaries of a production or distribution owner or operator's holdings are not discrete such as for other industry segments. And while the PSD and NSR programs might apply to stationary sources as defined by regulation, the scope of CAA section 114 is not so limited. The scope of the rule and the authority on which is based is not limited to regulated sources and to graft a source definition from other regulatory programs on the rule is neither appropriate nor reasonable, particularly inasmuch as the rule is intended to apply to or inform a plethora of programs or purposes. Further, while the rule might place emphasis on equipment owned or operated within the basin, we pointed out in the preamble to the proposed rule that we had limited the scope of the rule to the most significant emissions sources in the sector. Although some of those sources might be owned by other than the owner or operator, they are ultimately under their control and are their ultimate responsibility to control.

Finally, in today's final rule, we have revised the definition of natural gas processing facilities to not include gathering lines and boosting stations as an emissions source which should eliminate some of the commenter's concerns respecting aggregation.

Comment Number: EPA-HQ-OAR-2009-0923-1044-6
Organization: Colorado Department of Public Health and Environment
Commenter: Kirsten King

Comment Excerpt Text:
These additional inconsistencies between the MRR and PSD and Title V Permit Programs are sure to create confusion within the regulated community and make the inventory collected through the MRR inconsistent with permits and permitting inventories. While this confusion may

lead to what would otherwise be considered as recordkeeping and reporting noncompliance, once EPA's proposed Tailoring Rule takes effect, these violations may trigger further action under EPA's High Priority Violator Guidance.

Response: See response to comment EPA-HQ-OAR 2009-0923-1044-1. Further, as stated in the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), the preamble to today's final rule and in Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR, the purpose of the reporting rule is broadly to collect information to inform the Agency's understanding of greenhouse gases. The rule does not regulate greenhouse gas emissions and it is not intended to conform to any particular existing or contemplated regulatory air program, instead its purpose is simply to gather information, among other things, about the location and magnitude of emissions of greenhouse gases. While this information might be used in the future to regulate GHGs by permit or otherwise, such is not the exclusive purpose in collection of this data. And while there might be potential for some minimal confusion, all programs are not required to be completely consistent. EPA does not agree that the MRR will be inconsistent with existing permits and permitting inventories, because the existing inventories deal with non-GHGs whereas the MRR deals with GHGs in specific. Further, as to the relationship between the rule and any enforcement initiative, EPA cannot prognosticate or speculate how information collected under the rule might be used in any discrete or particular enforcement or compliance matter or initiative in the future. Please see Section VI of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), and Volume 8, Compliance and Enforcement, of the EPA's Response to Public Comments, dated September 2009.

See preambles and Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR for a more detailed discussion.

Comment Number: EPA-HQ-OAR-2009-0923-1173-14
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
Annual Report Due Date

Resolute Comments:

Given the vast amount of information that must be collected and compiled, Resolute does not believe that three months is sufficient time to collect, calculate and QA/QC the data needed to develop and submit a report. In addition, many industries are already obligated to submit several data-intensive reports to various agencies, including the EPA, in the first quarter of the year. These include Title V semi-annual monitoring reports and annual certifications under the CAA; quarterly deviation reports under the CAA; Discharge Monitoring Reports under the Clean Water Act; and Tier II reports under the Emergency Planning and Community Right-to-Know Act. Resolute requests that the EPA consider requiring annual reports to be submitted by June 30th of each year. This date would be consistent with other registry programs, such as that established by

The Climate Registry.

Response: EPA does not agree with the comment. Please see the preamble (Section II.J) of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), for the response on the selection of the reporting deadline.

Comment Number: EPA-HQ-OAR-2009-0923-1202-2
Organization: Enterprise Products
Commenter: Rodney Sartor

Comment Excerpt Text:
Aggregation -The aggregation of gas gathering and processing operations, as proposed in Subpart W, is inconsistent with current Clean Air Act ("CAA") regulations and other subparts of the greenhouse gas reporting program. It is also incompatible with actual ownership and operation scenarios for affected facilities.

Response: EPA does not agree with the commenter. However, EPA has not included reporting of emissions from the gathering and boosting systems in today's final rule. See Section II.E and II.F of the preamble to today's final rule for further details. For further details on legal authority to aggregate sources, please see Topic 2: Aggregation of Gathering and Boosting Systems with Processing Facilities in this document, Volume 9, of the Response to Comments.

Comment Number: EPA-HQ-OAR-2009-0923-1298-60
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
In the alternative, if EPA decides to proceed with the definition of "Onshore petroleum and natural gas production facility" as proposed, IPAMS requests that EPA expressly state that "the facility definitions proposed in this rule do not impact requirements under other EPA regulations, for example New Source Review (NSR)" in the rule itself, as it did on page 4 of the March 2010 FAQ document for Proposed Subpart W, or at a minimum provide a similar statement in the preamble to the final rule when it is published in the Federal Register.

Response: With regards to impact of today's final rule on other programs, please see the response to EPA-HQ-OAR-2009-0923- 1174-5.

9.4 COMMENTS RELATED TO PROCEDURES

Comment Number: EPA-HQ-OAR-2009-0923-1027-2
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.3(c)(11): Legal name(s) and physical address(es) of the highest-level United States parent company(s) and the percentage of ownership interest for each listed parent company… Also, on page 18613 of the Federal Register, under C. Definition of the Source Category, EPA states that "identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities.

OOC Comment: While the facility itself may have a single or multiple owners, each development and/or production field tied back to the facility may have multiple owners as well. This may significantly complicate the determination of percentage of ownership interest for each reporting entity. We feel the EPA should more clearly define the reporting expectations of ownership specific to offshore petroleum and natural gas facilities, and either remove the requirement to report percent ownership for offshore facilities, or clearly define facility ownership as applying only to the facility itself, and not its associated production fields.

Response: EPA has reviewed this comment. Please see Section 98.3 and 98.4 of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), which address reporting requirements and ownership issues. Furthermore, today's final rule amends Section 98.2 on who must report, requiring reporting from "owners and operators of any facility that is located in the United States or under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. §1331)…" and contains definitions for "offshore" and the "outer continental shelf."

Comment Number: EPA-HQ-OAR-2009-0923-1173-6
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
EPA should require that annual reports be submitted by June 30th of each year.

Response: EPA disagrees with the comment and is retaining the annual reporting due date of March 31. Please see the preamble (Section II.J) of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), for the response on the selection of the reporting deadline.

9.5 COMMENTS ON PORTABLE EQUIPMENT REPORTING REQUIREMENT

Comment Number: EPA-HQ-OAR-2009-0923-3524-3
Organization: Chesapeake Energy Corporation
Commenter: Grover Campbell

<u>Comment Excerpt Text:</u>
Emissions from Portable Non-self-propelled Equipment Should be Exempt Under Subpart W. EPA should not require reporting emissions from non-stationary and portable sources under Subpart W for the following reasons.

First, EPA is requesting the collection of this data under its Section 114 authority. Section 114 of the CAA allows the Administrator to "require any person who owns or operates any emission source . . . or who the Administrator believes may have information" to provide it in response to an information request. 42 U.S.C. § 7414 (emphasis added). Non-stationary and portable equipment is typically owned by contract service companies, not site operators. Moreover, in many cases, site operators do not have the operational data or the necessary records to perform the calculations necessary to certify the accuracy of GHG emissions data. Regardless of whether the equipment is stationed at a well site for more than 30 days, this equipment is often moved from well to well and between operators. Furthermore, because the site operator does not own this equipment, the site operator does not control its operation, does not perform or schedule its maintenance, and is not responsible for collecting the fuel consumption data. In short, EPA has greatly underestimated the difficulties site operators will face trying to track equipment and estimate emissions from field portable equipment that is owned and operated by third-parties. Therefore, consistent with its Section 114 authority and other provisions of the CAA, EPA should adopt provisions that determine applicability based on whether the party owns and/or operates a source. See, e.g., 42 U.S.C. § 7414(a)(1); 42 U.S.C. § 7410(a)(2)(F) (requiring owners and operators of stationary sources to install maintain and replace equipment in order to monitor emissions from sources); 40 C.F.R. § 60 .752 (establishing air emissions standards for owners and operators of municipal solid waste landfills).

Second, requiring petroleum and natural gas systems to report emissions from portable equipment under Subpart W would be inconsistent with EPA's approach elsewhere in the MRR. Requiring site operators to report these emissions under Subpart W places a disproportionate burden on the petroleum and natural gas systems sector because other provisions in the MRR, such as Subpart C, provide an express exemption for portable equipment, emergency generators, and emergency equipment. See 74 Fed. Reg. at 56,289 (Oct. 30, 2009). Similarly, the MRR does not require the reporting of emissions from other types of construction activities, such as housing, commercial building, or roadways. See 74 Fed. Reg. at 56,266-67 (Oct. 30, 2009).
Third, EPA's Section 114 authority is limited to emissions from stationary sources. 42 U.S.C . § 7414(a). The term "stationary source" is defined as "any building, structure facility, or installation which emits or may emit any air pollutant." 42 U.S .C. § 741 1(a)(3). It does not include portable equipment. Id EPA has cited no authority for extending the definition of stationary source to portable equipment that is stationed at a wellhead for more than 30 days in a reporting year. See 75 Fed. Reg. at 18,637 . Even if EPA were to adopt this provision despite it being contrary to law, the practical implication of imposing a 30 day limit on the equipment is that some site operators would change out the pieces of portable equipment onsite every 29 days to avoid these recordkeeping and reporting obligations.

Fourth, to require petroleum and natural gas systems to report emissions from portable equipment would also result in double counting of emissions and inaccuracies in the inventory. Providing an exemption for this equipment under Subpart W is reasonable because the vast majority of these engines are fired by diesel fuel and their emissions will be reported by suppliers of petroleum products under Subpart MM. Fifth, requiring estimates of the emissions from portable and leased equipment would greatly increase the reporting burden on the oil and gas industry without a corresponding increase in emissions reporting coverage. Emissions from portable equipment are such a small portion of the overall inventory that "the reporting of [these] GHG emissions is unreasonable given the cost of monitoring and the relative level of GHG emissions." See 74 Fed. Reg. at 56,291 (Oct. 30, 2009).

Finally, EPA could use other alternatives to estimate the emissions from this equipment because the total number and type of wells completed in the U.S. are well known facts. For instance, EPA could easily obtain a reasonable estimate of those GHG emissions using the Natural Gas Star data. The data provided from the Natural Gas Star program could be added to EPA's inventory to get a more complete emissions estimate for drilling and completing wells in the inventory. Therefore, it is unnecessary for EPA to impose this additional and disproportionate burden on petroleum and natural gas systems by requiring facilities to report emissions from portable equipment.

Response: First, EPA disagrees with the commenter on its authority to collect information from contracted equipment. Please see the response to EPA-HQ-OAR-2009-0923-1031-21 for further details.

Second, the EPA does not agree that requiring emissions from portable equipment is inconsistent with the general approach in the MRR. For further details, please see the response to EPA-HQ-OAR-2009-0923-1015-35.

Third**,** In today's final rule, EPA has removed the 30-day at wellhead clause for all portable equipment that have to be monitored. For further details, please see the response to EPA-HQ-OAR-2009-0923-1170-7. EPA's authority under Section 114 is not limited to collection of information from "stationary sources" as defined by the PSD/NSR program. See Volume 9, Legal Issues, of the EPA's Response to Public Comments for the Final MRR.

Fourth, EPA is not excluding combustion emission under Subpart W because of double counting under Subpart MM. For further information, please see the response to EPA-HQ-OAR-2009-0923-1042-26.

Fifth, EPA has clarified language and provided equipment threshold for external combustion equipment that will result in a reasonable burden on reporter to monitor portable, contracted, rented, and leased equipment. Please see response to EPA-HQ-OAR-2009-0923-1151-104 for further details.

Finally, EPA cannot use data from the Natural Gas STAR Program. For further information please see the response to EPA-HQ-OAR-2009-0923-1004-2.

Comment Number: EPA-HQ-OAR-2009-0923-0582-8
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
The WCI supports the proposed approach in SECTION 98.230(a)(2) of including portable non-self-propelled equipment within scope of onshore petroleum and natural gas production in Subpart W. Portable equipment may account for a substantial portion of emissions in this industry segment. However, WCI recommends that all portable equipment be included, rather than only the equipment stationed at a wellhead for more than thirty days, as proposed in SECTION 98.231(b). Portable equipment used in drilling, completions and workovers may often be on site for less than thirty days, but nevertheless collectively account for significant emissions. Because onshore production entities will report emissions at the basin level, recordkeeping would be simplified and verification would be easier without the necessity for tracking the time each piece of portable equipment was at a given wellhead. Given that the impacts of greenhouse gases depend primarily on global rather than local concentrations, the usual rationale for ignoring short-term temporary sources does not apply here.

Response: Please see the response to EPA-HQ-OAR-2009-0923-1040-5 for more details on reporting requirements for portable equipment.
EPA has removed the 30-day at wellhead clause for all portable emissions sources. For further details, please see the response to EPA-HQ-OAR-2009-0923-1170-7.

Comment Number: EPA-HQ-OAR-2009-0923-1031-23
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

<u>Comment Excerpt Text:</u>
The vast majority of engines included in this category are fired by diesel fuel. The amount of GHG emissions (both point and fugitive) from these portable non-self propelled equipment sources would be from combustion of diesel fuel. Emissions from non-road engines are exempt from reporting under Subpart C. Reporting GHG emissions from these engines under Subpart W would result in double counting of emissions since emissions from the combustion of diesel fuel are reported by suppliers of petroleum products under Subpart MM.

Response: EPA would like to clarify that since the emissions from portable combustion sources in onshore production is large, Subpart W requires the reporting of onshore production portable combustion emissions under Subpart W in today's final rule, overriding the exemption in Subpart C. EPA is not excluding combustion emission from engines under Subpart W because of double counting under Subpart MM. For further information, please see the response to EPA-HQ-OAR-2009-0923-1042-26.

Comment Number: EPA-HQ-OAR-2009-0923-1039-27
Organization: Interstate Natural Gas Association of America

Commenter: Lisa Beal

Comment Excerpt Text:
References to “portable” equipment: It is apparent that EPA expects emissions from portable equipment at production wellheads to be reported, but not portable equipment from other segments or applications. §98.230(a)(2) includes portable equipment for onshore production and §98.231(b) indicates emissions should be reported for portable equipment stationed at a wellhead. For clarity and to avoid confusion with underground natural gas storage wells, INGAA recommends revising §98.231(b) indicate, “You must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at an onshore production wellhead…”

Response: EPA agrees with the commenter. EPA has clarified that the reporting of portable equipment applies only to onshore production. This clarification has been provided in Section 98.232 of the rule.

Comment Number: EPA-HQ-OAR-2009-0923-1058-10
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller**:**

Comment Excerpt Text:
98.231 Reporting threshold.
Including emissions from drilling rigs located on a well for more than 30 days is unnecessary. See paragraph one under comments listed under § 98.230 above.

Response: EPA disagrees with the commenter on emissions from drilling rigs. Please see the response to EPA-HQ-OAR-2009-0923-1170-7 and EPA-HQ-OAR-2009-0923-1015-35 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1060-8
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Portable and Standby Equipment

EPA states, “For applying the threshold defined in 98.2(a)(2), you must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead for more than 30 days in a reporting year, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.” This requirement is unclear. Must it be the same piece of equipment (i.e., what if there are three different portable engines that together add up to >30 days)? It is important to note that equipment often moves from well site to well site, however, as written in the rule it appears that equipment must be tracked by basin. While it is common to track equipment by asset or business line, crossing basins will make this reporting requirement difficult to comply as it is information not currently tracked in this manner.

98.234(a) will require standby equipment to be included in annual leak detection which is overly burdensome: by nature, standby equipment is operated in short intervals, and is often operated in place of other equipment that would otherwise be emitting GHG emissions. Also, this requirement would force YPC field personnel to make multiple trips to each wellhead each year to quantify emissions that are otherwise minimal.

Response: EPA has removed the 30-day at wellhead clause for all portable emissions. For further details, please see the response to EPA-HQ-OAR-2009-0923-1170-7. In regards to tracking equipment by basin, please see response to EPA-HQ-OAR-2009-0923-1060-4.
In today's final rule, the use of word standby is used only to refer to an operational mode for a compressor. EPA has determined that most reporters understand the term standby with regard to compressors. EPA has clarified the term in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1206-59. EPA has also clarified in today's final rule that onshore production compressors only need to use an emissions factor to estimate process emissions (vented and equipment leaks) – no measurements are needed in the three modes of operation.

Comment Number: EPA-HQ-OAR-2009-0923-1151-23
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.231(a) Reporting threshold. Section 98.231(a) says to report emissions from petroleum and natural gas systems defined in Section 98.230. Section 98.231(b) says in applying the reporting threshold, include emissions from portable equipment that are stationed at a well head for more than 30 days in a reporting year. Section 98.230 does not include the same 30 day provision. Rather Section 98.230(a)(1) for onshore facilities says the facility includes "portable non-self-propelled equipment (including by not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment)." EPA should clarify that emissions associated with portable equipment stationed at a well-head less than 30 days are not reported. Reporting of portable equipment stationed on a well head less than 30 days will significantly add to the already burdensome requirements of the rule.

Response: EPA has removed the 30-day at wellhead clause for all portable emissions sources. For further details, please see the response to EPA-HQ-OAR-2009-0923-1170-7. EPA has clarified language and provided equipment threshold for external combustion equipment that will result in a reasonable burden on reporter to monitor portable, contracted, rented, and leased equipment. Please see response to EPA-HQ-OAR-2009-0923-1151-104 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1174-7
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text:

Portable Equipment Combustion Emissions

Devon contends that tracking and estimating emissions from portable combustion devices (e.g., drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters) that are stationed at a wellhead for more than 30 days in a reporting year would be resource intensive and complicated since this equipment is moved from well to well and between operators several times during the year. In many cases, the equipment is operated by contractor service companies and the facility owner or operator would, in most cases, not have the necessary records to estimate emissions and to certify the accuracy of GHG emissions data from these portable sources.

In order to minimize the burden of reporting emissions from third party owned/operated sources, we suggest limiting this requirement to the most prevalent sources, specifically drilling rigs and rental compression.

Response: EPA has removed the 30-day at wellhead clause for all portable emissions sources. For further details, please see the response to EPA-HQ-OAR-2009-0923-1170-7.
In today's final rule, EPA has restricted the list of portable combustion equipment required to report. However, EPA disagrees with limiting the list to just drill rigs and rental compression. For further details, please see Section II.F of the preamble. To further decrease the burden on the industry, EPA has provided an equipment threshold for external combustion equipment in onshore production and natural gas distribution. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1024-23. EPA has clarified language and provided equipment threshold for external combustion equipment that will result in a reasonable burden on reporter to monitor portable, contracted, rented, and leased equipment. Please see response to EPA-HQ-OAR-2009-0923-1151-104 for further details.

9.6 COMMENTS ON LEASED/RENTED EQUIPMENT REPORTING REQUIREMENT

Comment Number: EPA-HQ-OAR-2009-0923-1004-15
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
Because Reporting Responsibility for Onshore Natural Gas Production Can Be Complicated, EPA Should Provide Safeguards

The proposed Subpart W overlooks significant complications associated with determining reporting responsibility for onshore production wells. A single well can be owned by one entity, be operated by another entity, lease portable equipment from a third entity, and have that portable equipment operated by yet another entity. In these situations, the entities that directly operate certain equipment are in the best position to gather emissions data for that equipment, whereas other entities working at the same well site have limited ability to verify that data. Yet the proposed rule places the burden of reporting entirely on the owner of the well or the holder of the operating permit. This requirement could place onshore natural gas production entities in the impossible situation of being held to account for errors or omissions committed by third parties. NGSA respectfully requests that EPA address this concern by taking the following steps:
a. Allow Reporting Entities to Reasonably Rely on Operators. NGSA is concerned that in cases where a reporting entity must collect emissions data from other entities operating equipment at a particular well, the reporting entity could be held liable for non-obvious errors or omissions committed by those other entities. The Reporting Rule should allow reporters to reasonably rely on data supplied by operating companies associated with the production well. This "safe harbor" would not, of course, apply where reliance is unreasonable, such as when the reporting entity has reason to know that data is erroneous or false.

b. Disallow "Vicarious Liability" for Errors Committed by Reporting Entity.
NGSA is also concerned that entities in the onshore natural gas production sector that provide emissions data to reporting entities may then be held liable for subsequent errors or omissions committed by that reporting entity. EPA should clarify that an entity that provides properly collected emissions data to a reporting entity will not be held liable if that reporting entity commits an error or omission in reporting that data to EPA.

c. *Extend annual report submission deadline for onshore production facilities.*
NGSA is concerned that the annual deadline of March 31 for submission of emission reports will not allow sufficient time for production well owners and operators to collect and compile all necessary data from all entities responsible for operating the well. Therefore, NGSA respectfully requests that EPA extend the annual reporting deadline by 90 days for entities in the onshore production sector.

Response: Regarding item a, allow reporting entities to reasonably rely on operators, please see Section II.F of the preamble in today's final rule for a discussion of the role of the Designated Representative and also comment response EPA-HQ-OAR-2009-0923-1167-39.
Regarding vicarious liability, the focus of the rule is on reporting by owners or operators through a Designated Representative or Alternate Designated Representative and not third parties who might provide emissions data to the reporting entity. Owners or operators are free to provide or arrange for any third party indemnification which they might feel appropriate. See also, Section VI of the preamble to the October 2009 Greenhouse Gas Reporting Rule.

Concerning extension of the reporting period, EPA has determined not to extend the deadline. However, please also refer to Section II.F of the preamble in today's final rule for a discussion of data reporting requirements and the option to use Best Available Monitoring Methods.
The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final Rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-5
Organization: American Petroleum Institute
Commenter: Karen Ritter

Comment Excerpt Text:
Fourth, another key issue for the industry is its ability to track and estimate emissions from field portable combustion devices that are stationed at a wellhead for more than 30 days in a reporting year. EPA should require a less resource intensive and complicated approach that recognizes that this equipment is moved from well to well or between operators several times during the year. Similarly, API does not agree with EPA's extension of the reporting requirements to include rental and other equipment that is neither owned nor operated by the reporter.

Response: EPA took all comments on portable equipment into consideration and has removed the 30-day at wellhead clause in today's final rule to avoid practical issues with determining the time the portable equipment is at the wellhead. Please see the response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

EPA disagrees with the commenter to exclude rental and other equipment from the reporting rule. For further details, please see the response to EPA-HQ-OAR-2009-0923-1031-21.

9.7 COMMENTS ON REPORTING OF CONTRACTOR EMISSIONS

Comment Number: EPA-HQ-OAR-2009-0923-1040-5
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:

3. Emissions from portable non-self-propelled equipment (such as well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation related equipment) do not need to be reported.

EPA should delete the reporting of emissions from these non-stationary and portable sources. EPA should simply use its own updated total emissions estimates for these sources. The huge added expense for industry to calculate, keep records, and report emissions from thousands of these temporary sources is not justified by the small incremental emissions reporting accuracy EPA many be expecting from this approach. More specifically:

• Most wells arc drilled and completed using contract service companies. EPA underestimates the difficulty of tracking equipment and estimating emissions from field portable equipment that are operated by third parties even when stationed at a well site for more than 30 days. Complying with this requirement as proposed would be very resource intensive and complex since this equipment is often moved from well to well and between operators. In many cases, site operators would not have the operational data to perform the needed calculations and/or the necessary records to certify the accuracy of GHG emissions data. When the site operator does not control the operation or maintenance of the equipment, it is not appropriate to require reporting and compliance tasks of the well site operator because they do not participate in engine maintenance or the collection of fuel use data. All other Clean Air Act programs establish applicability based on whether a party owns and/or operates a source because it is not feasible for someone who does not control the day-to-day operation of a source to collect the required information or monitor the source's usage. No other industry sector is required to report contractor's emissions for this reporting rule.

• All of these activities are non-stationary source and temporary construction activities that should be excluded just as other construction activities (housing, commercial building, roadways, etc) are excluded. Requiring estimates of these emissions greatly increases the reporting burden on the oil and gas industry without a corresponding increase in emissions reporting coverage.

• The total number and type of wells completed in the U.S. is well known; therefore, EPA could easily obtain a reasonable estimate of those GHG emissions using the Natural Gas STAR data mentioned above. EPA could then add-on the emissions estimates for drilling and completing wells to the inventory.

• The vast majority of engines included in this category are fired by diesel fuel. The vast amount of GHG emissions (both point and fugitive) from these portable non-self propelled equipment sources would be from combustion of diesel fuel. Emissions from non-road engines are exempt from reporting under Subpart C. Reporting GHG emissions from these engines under Subpart W would result in double counting of emissions since emissions from the combustion of diesel fuel are reported by suppliers of petroleum products under Subpart MM.

Response: EPA disagrees with the commenter on emissions from portable equipment. The emissions contribution from portable equipment is significant enough to warrant data collection.

Please see the responses to EPA-HQ-OAR-2009-0923-1015-35 and EPA-HQ-OAR-2009-0923-1170-7 for further details.
EPA has removed the 30-day clause from today's final rule. Please see response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0582-7
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Contractor Emissions The WCI supports the EPA's proposed inclusion of contracted equipment within the onshore petroleum and natural gas production definition. The inclusion of contracted equipment is critical to ensuring that facilities with different operational structures have equitable coverage in a reporting (or cap and trade) program and that a complete profile of emissions from the production sector is obtained. Owners or operators will have the ability to include within contract terms that contractors must provide sufficient data to enable a complete greenhouse gas emissions report to be submitted. The WCI also notes that as greenhouse gases are a pollutant, overall responsibility for their release would seem to rest with the owner of the facility, instead of with contracted operators.

Response: EPA agrees with the comment. For a more detailed discussion of the inclusion of contracted equipment, please see Section II.E or Section II.F of the preamble of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1031-21
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
Most wells are drilled and completed using contract service companies. EPA underestimates the difficulty of tracking equipment and estimating emissions from field portable equipment that are operated by third parties even when stationed at a well site for more than 30 days. Complying with this requirement as proposed would be very resource intensive and complex since this equipment is often moved from well to well and between operators. In many cases, site operators would not have the operational data to perform the needed calculations and/or the necessary records to certify the accuracy of GHG emissions data. When the site operator does not control the operation or maintenance of the equipment, it is not appropriate to require reporting and compliance tasks of the well site operator because they do not participate in engine maintenance or the collection of fuel use data. All other Clean Air Act programs establish applicability based on whether a party owns and/or operates a source because it is not feasible for someone who does not control the day-to-day operation of a source to collect the required information or monitor the source's usage. No other industry sector is required to report contractor's emissions for this reporting rule, and the oil and gas industry should not be subject to a different standard.

Response: EPA does not agree with the commenter. With regards to tracking and gathering relevant information on third party equipment and contractor equipment, please see the response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

As articulated in the preamble to the Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) as well as in the MRR Response to Comments, Vol. 9, Legal Issues, the scope of Section 114 is quite broad and applies beyond persons who own or operate an emission source or who are otherwise subject to regulation under the CAA. Its purpose extends to the collection of information for "carrying out any provision" of the Act (emphasis supplied). We note, however, that subpart W does not require a contractor or third party to report emissions; that responsibility lies with the owner or operator of the applicable subcategory and industry sector. Section 114 (a)(1) provides that the Administrator may require any person who owns or operates an emissions source to collect and provide relevant CAA information to EPA. As explained, the owner or operator is in the best position to collect and report that information to the Agency.

The fact that emissions might be generated by equipment or processes owned by a party independent of the owner or operator of a particular facility is of not determinitive. The owner or operator has ultimate responsibility for the facility and the obligation and responsibility to assure that the required information can be collected through legally binding contracts, leases, or other agreements. This position that an owner or operator, through contract or other third-party agreement, cannot otherwise shirk CAA responsibility has long been that of the Agency(see authorities cited below). In recognition, however, of the fact that such contractual, lease or other binding provisions might not be in place in all instances, the rule allows a period of time during which best available monitoring methods may be applied. See Section II.F of the preamble to the final Subpart W rule for further details.

Although the MRR is not delimited by other CAA programs such as NSR or Title V, and EPA deems it inappropriate to tailor the provisions of the reporting rules to any specific program, we have explained this concept numerous times in the context of NSR or Title V which is here instructive and of precendtial value. The premise underlying this position lies in the notion that the owner or operator has the power to control, the "…power of authority to guide, manage, or regulate the pollutant-emitting activities of those facilities…." See, Guidance for Major Source Determinations at at Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act in Memorandum for Major Source Determinations for Military Installations, John S. Seitz, Director, Office of Air Quality Planning and Standards, August 2, 1996. Therein it is explained that because the contracting entity can control the contract operator's performance through contract terms, contract-for-service activities are considered part of a source. Likewise, the Agency has flatty stated its policy that "temporary and contractor-operated units [must] be included as part of the source with which they operate or support" and "that there are no provisions in title I or title V of the Act, or in regulations developed pursuant to them, for excluding contracted or temporary operations in defining major sources." Letter from John S. Seitz to Lisa J. Thorvig, Division Manager, Minnesota Pollution Control Agency, November 16, 1994. The underlying rationale for including sources over which an owner or operator exercises control in making major source determinations in the permitting context is thoroughly explained in 1995 guidance, Letter from William Spratlin, Director, Air, RCRA, and Toxics Division, EPA Region VII, to State and Local ir Directors, September 18, 1995

A more detailed discussion of this issue is found in Section II., Petroleum and Natural Gas Systems, of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1167-39
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Section 98.233(j) Onshore production and processing storage tanks. The rule indicates that this source applies to "emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter.)" Noble believes that compliance with the requirement for "including stationary liquid storage not owned or operated by the reporter" is overly burdensome and will not be practical because a reporter may not have access to the necessary operational data (i.e. throughput) nor legal access to the tankage to collect required samples (e.g. sales oil for API gravity and Reid vapor pressure) to perform the required calculations. Therefore, Noble requests that this section only applies when the tank is owned or operated by the reporting entity.

Response: EPA has revised Section 98.233(j) to make it clear that regardless of ownership of atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage), it is the onshore petroleum and natural gas production owner or operator who must report. For further details on legal authority to require reporting from leased, rented, and contracted equipment, please see the response to EPA-HQ-OAR-2009-0923-1031-21.

In addition, EPA provided methods in today's final rule that do not require the operational data from contractors (other than beneficial use or flaring of tank vapors) to estimate emissions. For example, the reporter can sample the low pressure separator oil and assume that all of the GHG dissolved in the oil is emissions. See response to EPA-HQ-OAR-2009-0923-1305-48 for further details on this option.

Comment Number: EPA-HQ-OAR-2009-0923-1196-2
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

Comment Excerpt Text:
This rule will require owners of a site to report GHG emissions resulting from rental and portable equipment located at a well head. Often, the owner of the site does not have emission information, or relies on information provided by a rental company (i.e., Compressor Systems, Inc.) that may or may not be accurate or acceptable by EPA standards. Note that §98.4(e) requires that emissions reports be certified by a "Designated Representative." The Designated Representative must therefore ultimately certify emissions for units they do not control, and there is no guarantee those emissions are auditable, verifiable, etc. IPANM requests that the EPA

determine that emissions from equipment that is on-site, but not under common ownership, does not need to be reported by the site owner.

Response: EPA disagrees with the commenter. With regards to the legal aspect of reporting emissions from equipment that is not under common ownership, please see the response to EPA-HQ-OAR-2009-0923-1031-21. In regard to collecting relevant data and reporting from portable equipment, see response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1201-16
Organization: North Slope Burough
Commenter: Edward S. Itta

Comment Excerpt Text:
Similarly, EPA should include all emissions from contracted equipment in the reporting requirements for the final rule—particularly in light of the extensive outsourcing within the industry. These emissions should be accounted for and aggregated with the contracting operator for threshold determinations.

Response: EPA agrees with the commenter and has retained the requirement for reporting of emissions from contracted equipment. Please see Section II.D of the preamble of today's final rule for more details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-55
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
As is common practice in the industry, operators contract with service companies to drill and complete their wells. Complying with this requirement as proposed would be very resource intensive and complex since this equipment is often moved from well to well, between operators, and even between geologic basins. In addition, since this equipment is controlled and maintained by third-party contractors, operators do not have access to the necessary information or data to report their emissions, or to certify as to the quality of any data that they might be able to obtain. All other CAA programs establish applicability based on whether a party owns and/or operates a source because it is not feasible for someone who does not control the day-to-day operation of a source to collect the required information or monitor the source's usage. No other industry sector is required to report contractor's emissions under EPA's MRR, and it should not be required under proposed Subpart W. IPAMS requests that EPA remove this requirement.

Response: EPA disagrees with the commenter. With regards to the legal aspect of reporting emissions from equipment that is not under common ownership, please see the response to EPA-HQ-OAR-2009-0923-1031-21 As regards collecting relevant data and reporting from portable equipment, see response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1032-3
Organization: State of New Mexico
Commenter: Jim Norton

2) Defining contractors as reporting entities would create problems with compliance and coverage of emissions.

Some commenters may suggest, as an alternative approach, that contractors themselves should be defined as reporting entities and be required to report their emissions directly to EPA. We consider this to be very problematic from the perspectives of compliance and coverage of emissions.

Proposed Subpart W currently defines reporting entities for onshore oil and gas production based on the holding of state drilling permits or state permits to operate oil and gas wells. This provides a known universe of potential reporting entities, which aids in ensuring compliance. The drilling or operating permit determines the accountability for the site. Companies which provide rental, leased or contracted equipment are not generally required to have permits specific to oil and gas production, which means that the universe of potential reporters who are contractors is unknown. This would greatly hinder effective compliance activities by EPA or state agencies.

Compliance would also be hindered by the transient nature of the emitting activities of contractors, given that some of the activities may occur at a given location for only a short period of time. Most regulatory and tracking systems are based on a specific physical location, and determining compliance for an entity which might operate a number of different locations, each for a short period of time, would be extremely difficult.

Companies providing rented, leased and contracted equipment range widely in size, from large multinational corporations to numerous small businesses. Many of the smaller companies would not exceed the 25,000 metric ton CO2e reporting threshold, and these unreported emissions may be substantial.

Response: EPA has retained the requirement for reporting of contracted equipment emissions in today's final rule and clarified EPA position on this issue; please see the response to EPA-HQ-OAR-2009-0923-1031-21.

Comment Number: EPA-HQ-OAR-2009-0923-1032-17
Organization: State of New Mexico
Commenter: Jim Norton

3) Owners and operators can control relevant aspects of the contractor's performance through terms of the contract.

Some commenters may assert that owners/operators cannot be held responsible for operations and data acquisition pertaining to rented, leased or contracted equipment. We believe there is ample precedent for owners/operators to obtain needed data from contractors through terms of the contract.

We note that EPA has addressed policy issues related to contractor emissions in the context of PSD and Title V programs. In several guidance letters, EPA has consistently stated that "contractor-operated units, must, be included as part of the source with which they operate or support" Contract/Temporary Operations and Title V, 11-16-94, in Memoranda for Operating Permits (Title V) -Policy & Guidance Memos, US EPA (www.epa.gov/ttn/oarpg/t5pgm.html). Although this policy is not necessarily binding on Subpart W of the Mandatory Reporting Rule, EPA's rationale for this policy is relevant: "the contracting entity can control the relevant aspects of the contract operator's performance through terms of the contract (e.g., the level of production, the requirement to implement and maintain emission control measures, the requirement to comply with all applicable environmental regulations, etc.)" Guidance for Major Source Determinations at DOD, 8-2-96, in Memoranda for Operating Permits (Title V) -Policy and Guidance Memos, US EPA (www.epa.gov/ttnloarpg/t5pgm.html). These EPA policies have been in place for many years, and sources in these air quality programs have been successfully held accountable for contractor compliance with environmental regulations.

We also note that holding owners/operators accountable for emissions from rented, leased or contracted equipment provides the owners/operators with several additional opportunities for emission reductions.

To the extent that any oil and gas sources are subject to EPA Tailoring Rule for greenhouse gases, it is highly likely that the EPA policy on contractor emissions at Title V source will apply in implementation of the Tailoring Rule. For consistency, the same policy should be applied to the reporting of GHG emissions.

We also note that vented emissions of natural gas are already considered the responsibility of the owner/operator under oil and gas conservation regulations and in common industry practice.

Response: EPA has retained the requirement for reporting of contracted equipment emissions in today's final rule and clarified EPA position on this issue; please see the response to EPA-HQ-OAR-2009-0923-1031-21.

9.8 OTHER LEGAL COMMENTS

Comment Number: EPA-HQ-OAR-2009-0923-3545-1
Organization: Environmental Defense Fund
Commenter: Pamela Campos

<u>Comment Excerpt Text:</u>
Please accept these comments on behalf of Environmental Defense Fund and our hundreds of thousands of members and supporters.

We greatly appreciate the opportunity to comment on EPA's Proposed Mandatory Reporting of

Greenhouse Gases for Petroleum and Natural Gas Systems. We support the Agency's proposal to require emissions reporting from the petroleum and natural gas sector, as required, and have separately submitted comments addressing the technical aspects of this proposal. Here, we write to underscore the critical nature of economy-wide greenhouse gas emissions data, including emissions data from the petroleum and natural gas sector. Emissions data are foundational – serving as the cornerstone for effective air quality planning and management; providing much-needed transparency for Americans concerned about global warming pollution in their communities; and making it possible to hold the largest polluters accountable for their greenhouse gas emissions.

Policymakers and the public have already lost a year's worth of this critical data, and EPA must act swiftly to satisfy its legal duty to require reporting from the petroleum and natural gas sector.

In two successive enactments, Congress pointedly instructed EPA to require mandatory reporting of greenhouse gas emissions "for all sectors of the economy of the United States" no later than June 26, 2009. See Fiscal Year 2008 Consolidated Appropriations Act, Pub. L. No. 110-161, 121 Stat. 1844, 2128 (Dec. 26, 2007) and Appropriations Act of 2009, Pub. L. No. 111-8, 123 Stat. 524, 729 (March 11, 2009). Congress thus called for a comprehensive program that encompassed not a few, not some, but rather "all" sectors of the economy. EPA's failure to promulgate final reporting requirements for petroleum and natural gas systems (40 CFR, Part 98, Subpart W) constitutes an ongoing failure to perform an act or duty under the Clean Air Act ("CAA"), 42 U.S.C. 7401, et seq., that is not discretionary with the Administrator within the meaning of 304(a) of the CAA, 42 U.S.C. 7604(a). We therefore urge EPA to take all final steps necessary to complete this rulemaking in a prompt manner and to fulfill its legal duty.

EPA possesses broad statutory authority to satisfy this legal duty and to require emissions reporting from the petroleum and natural gas sector. CAA sections 114 and 208 provide EPA with long-standing and expansive information-collection authority. See 42 U.S.C. 7414, 7542. Moreover, through successive revisions to its applicability and scope, Congress has broadened section 114 to include "persons not previously covered by [the section]." See H.R. Conf. Rep. 95564, Aug. 3, 1977. EPA's legal authority to require greenhouse gas emissions reporting from the petroleum and natural gas sector falls squarely within EPA's expansive statutory authority to collect information under sections 114 and 208 of the CAA and is consistent with past EPA practice.

In short, we have already lost a year's worth of critical emissions data from the petroleum and natural gas sector. EPA has both a legal duty to promulgate rules requiring the collection and reporting of this data and broad statutory authority supporting promulgation of such rules. We appreciate EPA's reaffirmation in this supplemental proposal of the urgent need to require reporting from the petroleum and natural gas sector, and we urge EPA to move expeditiously in finalizing this rule, as well as the reporting requirements for other sectors missing from the October 2009 Rule, in order to satisfy its legal mandate to require emissions reporting from "all sectors of the economy of the United States."

Response: EPA initially proposed Subpart W in 2009 with the other sectors of the industry. However, stakeholders raised concerns regarding the burden to report to the 2009 proposal as well as the emissions coverage that would be missing due to the exclusion of onshore production and distribution sectors from the 2009 proposal. To address these issues, EPA re-proposed Subpart W in 2010 and has today finalized the rule.

EPA notes that the establishment of reporting requirements for these source categories is appropriate and within EPA's legal authority. Please see the preamble (section II.Q) of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), as well as Vol. 9 Response to Comments, Legal Issues on the 2009 final rule, for a discussion of EPA's legal authority to collect the data required by this rule. See also 75 FR 39736, 39752 (July 12, 2010) for a discussion on how the appropriations language grants EPA much discretion to determine the appropriate source categories to include in the reporting rule. On a national basis, GHG emissions from the oil and gas industry are second only to power plants. Hence, EPA has determined that it is necessary to collect an accurate amount of GHG emissions information from this sector.

VOLUME 10: COST AND ECONOMIC IMPACTS OF THE RULE

10.0 COST AND ECONOMIC IMPACTS OF THE RULE

No comments received.

10.1 METHODOLOGY USED TO ESTIMATE COST IMPACTS

Comment Number: EMAIL-0001-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
Economic Impact Analysis

We are in the process of evaluating the economic impact analysis provided by EPA. At this point it appears that EPA's cost estimates for impact on the industry are low by one to several magnitudes. EPA fails to realize the massive amount of data collection and recordkeeping required to calculate emissions from the vast majority of some 700,000 well sites in the U.S. The only feasible alternative is to adopt simple threshold exemptions and simplify the data gathering requirements and calculations by use of widely accepted methodologies such as the API Compendium. Industry and the EPA would be much better served by spending resources to improve any emission factor methods that EPA feels is not representative of actual emissions (e.g., well blowdowns).

We are particularly concerned with the requirement to count all fugitive components on every well site and small production facility that we operate. This requirement is very significant in terms of effort and cost. Thus, it is critical to us to receive relief on fugitive component inventory.

Response: EPA has reviewed its estimates and disagrees that they are too low by an order of magnitude or more. See EPA's response to comment EPA-HQ-OAR-2009-1151-107 for more details. EPA also disagrees that emissions will have to be calculated from the vast majority of 700,000 wells in the U.S. See response to comment EPA-HQ-OAR-2009-0923-1151-89 for further details.

EPA has considered the commenter's recommendation for threshold exemptions and simplified data gathering requirements. In particular, EPA agrees that the burden for counting components for equipment leak emissions could be large to some reporters. Today's final rule has several modifications that will considerably reduce reporting burden and simplify monitoring methods.

Please see Section II.E of the preamble (EPA-HQ-OAR-2009-0923) for complete details about changes EPA has made in today's final rule to reduce the burden to quantify equipment leaks; see "Equipment-Level Population Emission Factors for Onshore Production" (EPA-HQ-OAR-

2009-0923) and EPA's response to EPA-HQ-OAR-2009-0923-1151-107 for more information on quantifying emissions from major equipment counts. Please also see response to EPA-HQ-OAR-2009-0923-1151-5 for discussion about changes EPA made to today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component.

Finally, today's final rule provides equipment thresholds that will significantly reduce burden to monitor and report emissions. See Section II.F of the preamble and the response to comment EPA-HQ-OAR-2009-0923-1151-5 for more details.

Comment Number: EPA-HQ-OAR-2009-0923-0050-6
Organization: Southwest Gas Corporation
Commenter: Jim Wunderlin

Comment Excerpt Text:
Total Cost for Process Emissions

Given the above discussions, Southwest believes that the Process Emissions cost estimate described in the preamble of the proposed rule is significantly underestimated. The published cost estimate for the natural gas distribution sector is estimated to be $1,680,000 for start up and $600,000 for annual costs thereafter. Southwest respectfully suggests that these costs are more likely to be $1,680,000,000 and $600,000,000, respectively

Response: EPA has reviewed the cost estimates of the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) and disagrees that the Agency significantly underestimated the costs for the natural gas distribution segment. See EPA-HQ-OAR-2009-0923-1020-6 for EPA's response to the commenter's alternative cost estimate.

Comment Number: EPA-HQ-OAR-2009-0923-1016-11
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
EPA Has Vastly Underestimated Costs – Changing or Eliminating the Annual Leak Survey Proposal Would Help Reduce Compliance Costs Substantially

1. Reasons for EPA's Underestimate of Cost Impacts

EPA has estimated that the total industry-wide annual cost of complying with Subpart W for natural gas distribution will be $1.6 million in the first year and $1 million per year thereafter.[98] EPA estimates that 143 LDCs will be subject to Subpart W using a facility threshold of 25,000

[98] 75 Fed. Reg. at 18625, Tables W-5 and W-6.

tpy CO2e.[99] Accordingly, EPA is estimating a per company cost of $11,188 in the first year and about $7,000 per year per LDC thereafter. In contrast, as described later in these comments, AGA members estimate the cost of complying with the leak survey requirement in the rule will be orders of magnitude higher.

EPA has seriously underestimated the cost of complying with the 2010 Proposal, for at least four reasons. First, the 2010 Proposal uses the undefined terms “above ground meter regulators” in sections 98.232 and 98.233[100] and “metering stations and regulating stations” in section 98.238 (defining a natural gas distribution facility) that could be interpreted to include not only city gates and large custody transfer or district metering and regulating (M&R) stations but also industrial, commercial and even residential customer regulating and metering equipment. We do not believe this was EPA’s intent, but unless the term is clarified, regulatory uncertainty and the risk of varying interpretations by field enforcement personnel would drive LDCs to include all customer meters in their leak surveys and reporting. When multiplied by 65 million customer meters across the country, the significant annual leak survey costs would result in billions of dollars of unnecessary cost to gas utilities and their customers.

Second, the agency has underestimated the cost of conducting an annual leak survey of the eight listed components using optical scanning equipment at distribution city gates, above ground meter regulator stations and at underground storage facilities. Requiring the use of infrared cameras significantly increases this cost.

Third, our members do not have inventories or records for all eight of the components listed in section 98.232(f)(5) and (i)(1). They would have to visit each meter and regulator location (depending on the definition of M&R) to develop the list required for applying component-level emission factors to component counts. The burden of this proposal could be reduced significantly by reducing the number of components and better defining them so it is clear what is to be included. The burden could be eliminated by allowing the use of facility-level emission factors for city gates and above ground M&R facilities, as EPA has proposed for below-ground M&R facilities and vaults.

Fourth, EPA has underestimated the costs of making an initial threshold determination for small distribution systems and other small facilities that likely fall below the threshold. These facilities apparently would have to conduct a full leak survey using optical scanning in the first year in order to determine whether a distribution, underground storage, transmission compression facility or LNG facility does or does not exceed the 25,000 tpy regulatory threshold under §98.2(a)(2). EPA could avoid this burden by allowing small facilities to use a simpler threshold determination method that does not require leak surveys or other field work.
Because M&R is Not Clear Defined and Could Apply to Customer Meters, Distribution M&R Leak Survey Costs Could be Extremely Burdensome and Costly

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[99] EPA, Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Supplemental Rule (GHG Reporting), Final Report (Dec. 8, 2009) (Economic Analysis) at page 4-5.

[100] Proposed 40 C.F.R. §§98.232.(i), 98.233(q)(7), 75 Fed. Reg. 18637, 18643.

Even without requiring infrared cameras, EPA's annual leak survey requirement would impose far greater costs than it has estimated, largely because the proposal could be interpreted to apply to millions of customer meters. The cost of employee time for visiting an individual meter installation is not large, but when multiplied by millions of meters, the costs expand exponentially. Based on a recent survey, discussed in greater detail below, AGA members estimate that the incremental cost for conducting the annual leak detection called for in Subpart W would be roughly $40 per inspection per city gate station or district regulator station or per industrial or commercial customer meter if infrared cameras are not required – roughly one hour of technician time plus travel time.

Response: EPA disagrees that the Agency underestimated the rule's compliance costs by orders of magnitude. Please see Section III.B of the preamble to today's final rule for EPA's response to three of the assumptions that the commenter identified above as the basis for its alternative estimate (inclusion of customer meters; annual leak survey costs; and cost to make reporting determinations, e.g. "threshold determinations"). As explained in Section III.B of the preamble, EPA has identified the specific assumptions that accounted for the discrepancy between the estimates; EPA also updated its estimate to include the cost for non-reporters to make a reporting determination.

EPA agrees that the costs to visit an individual meter installation are not large, but disagrees with the commenter's total estimate because it included many sources that are not subject to today's final rule. The requirements do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps. See preamble Section II.F for a complete discussion about the meters. EPA intended to include in the rule. In addition, EPA has revised today's final rule to allow alternative options for leak detection. See preamble Section II.F for details about the alternative leak detection options.

Regarding the inventory of components, EPA agrees that counting all the components, regardless of whether they are leaking, at each facility is burdensome. Therefore, today's final rule requires reporters to inventory *leaking* components only at above ground custody transfer city gate stations. Furthermore, today's final rule clarifies that the requirements do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps; see preamble Section II.F for a complete discussion about the meters EPA intended to include in the rule.

Regarding the costs to inventory leaking components, EPA included travel to custody transfer city gate stations and the associated labor in its estimates. In today's final rule, EPA assumed the following for each of these stations: 30 minutes to complete a station survey; per diem costs of $50 and accommodation costs of $100 per day; and 30 minutes driving between surveyed stations at a cost of $0.50 per mile traveled.

Because today's final rule does not require a component count at non-custody transfer M&R stations, underground vaults, and main and service lines, EPA did not assume travel costs to these locations. Instead, reporters can estimate emissions for these sources using population emission factors. Therefore, EPA estimated the costs for reporters to apply emission factors to above ground meter and regulators (non-custody transfer city gate stations) as well as below ground meter and regulators and vaults that are not customer meters. Furthermore, EPA did not estimate any costs for customer meters because they are not subject to the rule.

EPA agrees that additional clarification and only the use of population emissions factors (i.e. facility-level emission factors) would reduce compliance costs. However, EPA determined that the use of leaker emissions factors (i.e. emission factors applied to components that are found to be leaking during a leak survey) will provide an estimate of “actual” emissions, as opposed to the use of population emissions factors, which estimates the "potential” of emissions from each station (see “Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD” (EPA-HQ-OAR-2009-0923-0027), Section 4). EPA determined that estimating “actual” emissions from equipment leaks in the processing, transmission, underground storage, LNG storage, LNG import/export terminals, and distribution segments is necessary to track changes in emissions from the various facilities and effectively inform policy. Therefore, EPA did not modify the requirement to use leaker emission factors at above ground meter and regulator city gate stations at which custody transfer occurs.

Comment Number: EPA-HQ-OAR-2009-0923-1020-5
Organization: Southwest Gas Corporation
Commenter: James F. Wunderlin

<u>Comment Excerpt Text:</u>
Cost of Component Inventory

Unlike many utilities, Southwest has a robust electronic work management system which could be used to track components that emit GHGs. Unfortunately, the types of components required to be inventoried for compliance with the proposed regulations are not included in this electronic data base and it would be very costly and time consuming to conduct the initial inventory.

Furthermore, the cost of conducting a survey of regulator stations during the required five-year cycle is approximately $2.7 million. If an annual inventory is required for all regulator stations, the five-year cycle cost would be approximately $9.7 million. These costs do not include inventories of single-family residential meters and regulators.

Response: EPA considered this comment and similar statements from other commenters regarding the costs to inventory equipment.

EPA is unable to evaluate the commenter’s estimates ($2.7 million and $9.7 million) because insufficient documentation was provided to explain how these figures were calculated. For example, the basis for the commenter’s estimate that a component inventory would incur a five-year cycle cost of $9.7 million is unclear, given that the commenter did not specify assumptions about time and activities to inventory. Nonetheless, EPA has inferred that a large part of the commenter’s cost estimate can be attributed to the misinterpretation that customer meters are subject to leak detection requirements. This rule, however, does not require reporters to count the leaking components from all stations and meters. See EPA’s response to comment EPA-HQ-

OAR-2009-0923-1016-11 for a discussion that clarifies the component count requirements under today's final rule and for discussion about how EPA account for the labor and time involved in the inventory.
While the commenter's electronic work management system may not include all types of components that are prescribed for monitoring under subpart W, EPA can not possibly develop a rule that could match each and every company's work management system and EPA does not prescribe that the commenter must use this system in relation to Subpart W. However, EPA disagrees with the commenter's assessment of the burden for the distribution segment because today's final rule requires component leak detection only at above ground meter & regulator city gate stations at which custody transfer occurs (this does not include customer meters). EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 clarifies the requirements and associated costs.

Comment Number: EPA-HQ-OAR-2009-0923-1060-1
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Cost of Implementation

EPA has grossly underestimated the cost of implementation for this reporting rule. According to EPA's guidance, staff activities and labor were taken into consideration when drafting the proposed rule. However, if the required sources to report remain aggregated by basin, the number of affected facilities as well as travel to those affected facilities in remote areas does not appear to have been taken into consideration; nor has the GHG emissions from vehicles traveling to remote locations been taken into consideration. Furthermore, the EPA's cost estimation assumes that staff exists on-site to assist with GHG reporting implementation: the opposite is true. Many operators will be forced to hire additional temporary staff or utilize consultants to review and compile data from various divisions in order to determine if Yates is indeed in compliance with the proposed rule.

Response: EPA's cost estimate accounts for the labor and equipment costs expected to occur as a result of this rule; EPA did not include costs incurred in the absence of this rule. EPA disagrees with the commenter's characterization of its cost estimates. In particular, EPA did not assume staff exist on-site to assist with GHG reporting implementation. Furthermore, operators will not need to hire additional staff or make special trips to comply with Subpart W, as explained below.

EPA disagrees with the commenter's implied assumption that facility workers do not visit well sites—remote or otherwise—at least once per year. While EPA recognizes that well sites generally operate unmanned throughout the year, operators still monitor the associated equipment of interest under today's final rule, such as gas-liquid separators, wellhead dehydrators, wellhead compressors, stock tanks, and heaters. For example, operators monitor the wellhead compressor lubrication and operating hours, glycol dehydrator glycol regenerator temperatures, glycol chemical color and level, glycol circulation pump flow setting, and methanol inventory and injection pump rate settings. Also, company maintenance practices require operators to periodically visit well sites that have this operating equipment to ensure, for example, that fluid levels are proper and that automatic equipment functions properly; in the case of well venting for liquids unloading, this is often a manual operation. Depending on the wellhead equipment, this site visit may be once per year or, for wells that need frequent manual liquids unloading, as frequently as once per week. These visits will take place even in the absence of today's final rule.

However, EPA agrees that counting individual components at well sites is burdensome and has revised today's final rule to allow reporters to instead count major equipment to quantify equipment leaks. Operators will often know major equipment counts because they keep an inventory for maintenance purposes. In addition, EPA agrees that many well sites operate without any significant wellhead equipment. Given that today's final rule requires a count of major equipment rather than individual components, operators will not need to visit wells without major equipment at the wellhead

For the wellsites with major equipment, operators can count their major equipment during routine visits to well sites even if they don't already have this inventory available. Accordingly, EPA's burden estimate included the extra time spent at each site to collect relevant data for reporting to this rule but did not account for the travel to site because it would occur in the absence of this rule. For more information on quantifying emissions from major equipment counts, please see rulemaking docket (EPA-HQ-OAR-2009-0923) under "Equipment-Level Population Emission Factors for Onshore Production."

Finally, the commenter's did not provide sufficient information about its recommendation to account for the GHG emissions from vehicles used to travel to well sites. Based on EPA's interpretation of this statement, the recommendation irrelevant and beyond the scope of the economic impact analysis. If the commenter was referring to emissions reported under Subpart W, EPA notes that the rule does not require reporting of vehicle emissions. Rather, Subpart W requires reporting of emissions data about key sources in the petroleum and natural gas industry. Alternatively, the commenter may have intended to suggest that EPA evaluate the cost of impacts from vehicle GHG emissions rather than the cost to monitor them. As discussed in chapter 1 of the EIA, the purpose of the economic impact analysis is to illustrate the types of costs and benefits that may accrue as a result of Subpart W, in particular the compliance costs for reporters. EPA does not expect the monitoring activities under Subpart W to significantly affect the level of GHG emissions from each reporter's facility, since most of the well sites are already being visited as a part of routine operations. Second, even if EPA were to estimate the GHG emissions associated with Subpart W compliance activities, it would be incorrect to attribute all vehicle emissions resulting from travel to well sites to Subpart W because such travel occurs in the absence of this rule.

Comment Number: EPA-HQ-OAR-2009-0923-1170-9
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:
EPA's estimate to comply with Subpart W is greatly disproportionate to Pioneer's calculated estimate and compliance will be unduly burdensome

Pioneer believes the EPA has severely understated the cost and burden of this Subpart. According to EPA documents, EPA has estimated that it will cost an operator $ 18,000/facility for the first compliance year, and $8,000/facility every year thereafter. As stated above, the cost Pioneer has calculated for laboratory work to conduct sampling in the Permian Basin alone as mandated by the Onshore Production segment, $17.2 million, greatly exceeds the EPA estimated costs and will be an extremely enormous burden from a personnel and cost standpoint. This cost does not include compliance with 98.233 (u) and (v), mentioned above, to determine the mole percent in order to calculate the volumetric and mass emissions for CO_2 and CH_4 for many of the source categories; these sections were very unclear and it was impossible to determine the sampling protocol required. It also must be emphasized again that this cost estimate is only for one of Pioneer's many asset areas, Permian. Further, it does NOT include the cost of manpower to travel to each battery, count each of the 21 equipment sources potentially present at each wellhead and battery (as mandated by the Onshore Production segment of this Subpart, take the samples, or enter the data. Nor does it take into account the equipment required for sampling or a GHG software program to manage the data as explained in point 9.

Response: EPA is unable to evaluate the commenter's estimate [of $18,000/facility and $8,000/facility] because insufficient documentation was provided to explain how these figures were calculated. Regarding the EPA estimates cited by the commenter, they refer to the cost ($18,000) for the *average* operator per facility for the first compliance year and $8,000 per facility for every year there after; larger operators and facilities will incur greater costs depending on geographic dispersion and equipment owned. The average cost for a *large* onshore production operator per facility is $35,000. Please see the response to EPA-HQ-OAR-2008-0508-1151-107 for a discussion on estimating Subpart W's burden on the onshore production segment.

Regarding the comments about sampling, please see EPA's response to EPA-HQ-OAR-2009-0923-1011-21 for more details on Subpart W's sampling requirements and Section II.F of the Preamble (EPA-HQ-OAR-2009-0923) for EPA's response to this comments and others concerned with sampling burden.

Finally, EPA disagrees with commenter that EPA has not accurately accounted for the costs to visit well and ancillary well sites and the associated monitoring (count components and take samples). Please see EPA's response to EPA-HQ-OAR-2009-0923-1060-1 for how EPA accounted for well site and ancillary well site visits and response EPA-HQ-OAR-2009-0923-1151-106 about the use and cost of GHG software programs.

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Comment Number: EPA-HQ-OAR-2009-0923-1298-41
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:

EPA has greatly underestimated the cost and effort to conduct the direct measurement prescribed for these sources. Based on the monitoring requirements of the proposed rule for the reciprocating compressor rod packing venting source type alone (only one of 21 source types listed under the onshore petroleum and natural gas production sector), an IPAMS member company projects that the cost will exceed $108,000 per compressor unit alone and in excess of $650,000 per "facility" (as EPA has defined the term for a hydrocarbon basin) based on the following cost data and assumptions:

Description	Qty.	Unit Price	Count	Total Cost	Notes
Affected basins			25		
Reciprocating compressors			150		
Cylinders per compressor			2		
Operating modes requiring measurement			3		
Measurement contractor	4 hr	$250		$900,000	Assumes high-flow sampler instead of meter
Operator to assist contractor	3 hr	$100		$270,000	Labor includes travel time
Quarterly gas samples	4	$200		$120,000	
Install compressor throughput flow meter	1	$100,000		$15,000,000	Total installed cost
Conduct flow measurement and calibration	1 hr	$100		$15,000	Requires flow through each compressor

This is in comparison to EPA's Subpart W estimate of $18,000 for all source types combined at an entire facility for the first year. Any one company will have hundreds or thousands of compressors in operation, each one with multiple compressor rod packings, and many that may be leased rather than owned by the reporting entity. Additional complexity and cost are presented in the many cases when a single compressor is used for multiple services, for example inlet compression, residue compression, and refrigeration compression. To further complicate the required reporting, EPA has required that the GHG measurements be conducted three times for each unit: once while operating, once while in standby mode, and once when depressurized. Not only does this triple the already onerous resource requirements to collect the data, but requires the depressurization of a compressor, thereby creating additional GHG emissions via compressor blowdowns, just to take a third measurement that will likely be a "zero" reading unless a valve has malfunctioned. Therefore, IPAMS requests that EPA allow operators to use the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Gas Industry (API Compendium) to calculate GHG emissions from rod packing venting.

Response: In response to this comment and others, EPA has decided not to require direct measurement of reciprocating rod packing vents for onshore production under today's final rule. Please refer to :Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0923) for the basis for this change and details on quantifying emissions from reciprocating compressor rod packing. In addition, today's final rule clarifies that EPA did not intend for compressors to be taken offline in order for reporters to collect the data required under Subpart W. However, EPA disagrees with the recommendation to use the API Compendium; please see comment EPA-HQ-OAR-2009-0923-1061-14. See EPA-HQ-OAR-2009-0923-0055-16 for complete discussion about the monitoring requirements and compressor mode and the monitoring requirements.

10.2 VERIFICATION METHODOLOGY AND COSTS

Comment Number: EPA-HQ-OAR-2009-0923-1016-16
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:

This is important, because the type of leak detection equipment required by Subpart W could affect the cost significantly. The following are general estimates of the cost of each of the possible devices that could be considered to be "optical gas scanning equipment" --

FLIR camera/ Optical Imaging Device: Cost around $80,000 to $100,000 each to purchase – around $2,500 per week to rent;

Mobile or Remote Methane Leak Detector (RMLD): Cost around $30,000 each;

Vehicle-Mounted Methane Leak Detector: Cost around $16,000-18,000 each; and

Remote hand-held optical methane detectors: Cost around $8,000 each.

In Exhibit B to these comments, we provide estimated costs of conducting the proposed annual survey using optical scanning devices – assuming this term refers to infrared cameras. AGA estimates that it would cost about $2,900 per city gate to conduct the annual inspection using an infrared camera, compared to $40.51 per city gate using other, often more methods that are more effective for finding small leaks and are currently used by LDCs in leak surveys required under existing federal and state pipeline safety regulations. The costs of using infrared cameras at other M&R locations varies by type of metering location –

- $2,900 per city gate
- $860 per district M&R station from transmission (custody transfer other than at city gate)
- $244 per district M&R station (stepping down pressure within distribution system)
- $377 per industrial meter
- $30 per commercial meter
- $30 per residential meter (assuming similar to commercial meter costs)

One can multiply the per location estimates by the total number of city gates, custody transfer stations, industrial meters, commercial meters and residential meters in the U.S. (based on the DOE EIA numbers of meters) to determine total cost for requiring infrared cameras at each type of metering and regulating location. This will result in a conservative estimate of cost impacts, as this member did not include travel time for the service personnel and did not use fully loaded labor costs (i.e. did not include the cost of benefits).

AGA conducted an informal survey of its membership in June 2010 to estimate the number of city gates, district M&R stations, and industrial, commercial and residential meters that are potentially impacted by the proposed rule. AGA members reported the following:

- Each LDC serves an average of 143 city gate/custody transfer stations
- Each LDC serves an average of 1,434 district regulator stations on distribution lines and 118 district regulator stations on intrastate transmission lines
- Each LDC serves an average of 9,498 industrial meters on distribution lines and 256 industrial meters on intrastate transmission lines
- Each LDC serves an average of 57,616 commercial meters
- For LDCs that track multi-family residential meters separate from commercial meters, each LDC serve an average of 265,878 multi-family residential meters
- Each LDC serves an average of 789,758 residential single-family meters

From these estimates, one can calculate that each LDC operator will, on average, incur the following annual costs if required to use infrared cameras for leak detection surveys:

- $413,250 for city gates
- $101,193 for district M&R stations from transmission (custody transfer other than at city gate)
- $349,877 for district M&R stations (stepping down pressure within distribution system)
- $3,677,581 for industrial meters
- $1,728,468 for commercial meters
- $7,976,346 for multi-family residential meters
- $23,692,732,181 for single-family residential meters

These costs are absurdly high, especially considering that our members report that the infrared FLIR cameras often cannot locate the typically small leaks in distribution systems that can be found using a simple soap bottle leak detection technology. This and other traditional methods may be less “sexy” but they are usually far more accurate and less expensive that infrared FLIR cameras for finding small leaks. It would be truly absurd to require an LDC to pay $100,000 for each infrared FLIR camera, when they can get better results using a bottle of soapy water for a few dollars. The optical scanning equipment should be an option but not a requirement.

This informal survey also collected estimated costs for leak inspection that does not include infrared camera costs. AGA members estimated the following leak inspection costs per LDC per year, on average:
- $33,938 for city gates
- $281,390 for district M&R stations
- $1,196,977 for industrial M&R station
- $4,603,376 for commercial meters
- $19,235,507 for multi-family residential meters
- $15,761,135 for single-family residential meters

AGA estimates that the requirement to use infrared cameras for leak detection will cost each operator, on average, $37,939,450. In addition, AGA estimates the additional resources that would be needed to fulfill the leak inspection requirements in the proposed Subpart W will cost each operator, on average, $41,112,323 per year. The total potential fiscal impact for each LDC operator is, therefore, $79,051,773 per year. These costs reflect the first year of implementation. The following years would require the same level of resources of leak inspection, but would require a different level of resources for the use of infrared cameras. These costs would depend on the purchasing or renting of infrared cameras, the training of personnel using this technology and the administrative and maintenance costs associated with the implementation of this technology.

These fiscal estimates reflect responses provided by 30 LDC operators with widely varied system compositions and operational considerations. A more accurate cost estimate would require additional time that the comment period does not allow. However, from the responses provided, AGA is comfortable asserting that the strain the 2010 Proposal would place on limited resources is overly burdensome. Given the low emissions from distribution systems, clearly, the cost per ton would be excessive even for a cap and trade system, let alone a reporting rule that will not result in any GHG emission reductions.

There are more than 70 million residential, commercial and industrial customers in the U.S. If leak surveys were required at each meter, even without using infrared cameras, the cost would be $2,835,700,000 – nearly $3 billion per year, and that is without requiring infrared cameras.

AGA accordingly requests that EPA allow the use of other effective leak detection equipment and to revise sections 98.232, 98.233 and 98.234 to clarify that the term Natural Gas Distribution Facility does not include customer meters and that LDCs are not required under Subpart W to leak survey or report fugitive emissions from industrial, commercial and residential customer meters.

EXHIBIT B to AGA Comments, June 11, 2010, Docket No. EPA-HQ-OAR-2009-0923

GHG Reporting Sub Part W Potential Impacts

Table 1

Impacted Facilities	Number of Facilities	Cost For Additional Annual Inspection	Cost For Optical Scanning/Infrared Cameras	Cost For Additional Administration/ Record Retention	Cost Inspection during Normal Cycles	Cost for Using Existing Leak Detcection Equipment
City Gate Stations						
State A	4	$ 162	$ 64,500	N/A		
State B	91	$ 3,686	$ 387,000	N/A		
State C	179	$ 7,251	$ 129,000	N/A		
State D	38	$ 1,539	$ 129,000	N/A		
State E	0	$ -	$ -	N/A		
State F	0	$ -	$ -	N/A		
Subtotal		$ 12,639	$ 709,500			
District Regulator Stations at Pipeline						
State A	0					
State B						
State C	150	$ 6,077	$ 129,000			
State D	97	$ 3,929	$ 64,500			
State E	100	$ 4,051	$ 64,500			
State F	50	$ 2,026	$ 64,500			
Subtotal		$ 16,082	$ 322,500			
District Regulator Stations						
State A	792	$ 32,084	$ 193,500	1 FTE - $60,000		
State B	1654	$ 67,004	$ 774,000	1 FTE - $60,000		
State C	880	$ 35,649	$ 193,500	.5 FTE - $30,000		
State D	238	$ 9,641	$ 193,500	.5 FTE - $30,000		
State E	1836	$ 74,376	$ 967,500	.5 FTE - $30,000		
State F	936	$ 37,917	$ 967,500	.5 FTE - $30,000		
Subtotal		$ 256,671	$ 3,289,500			
Industrials Meters / Served by transmision pipeline						
State A	9	$ 729		N/A		
State B	77	$ 6,239		N/A		
State C	10	$ 810		N/A		
State D	6	$ 486		N/A		
State E	8	$ 648		N/A		
State F	0			N/A		
Subtotal		$ 8,912				
All other Industrial Meters						
State A	342	$ 17,318	$ 129,000			
State B	749	$ 37,927	$ 193,500			
State C	77	$ 3,899	$ 64,500			
State D	205	$ 10,381	$ 129,000			
State E	598	$ 30,281	$ 193,500			
State F	110	$ 5,570	$ 64,500			
Subtotal		$ 105,377	$ 774,000			
Commercial M&R Stations						
State A	7,000	$ 212,678		1 FTE - $60,000		
State B	7458	$ 226,593		1 FTE - $60,000		
State C	1730	$ 52,562				
State D	614	$ 18,655				
State E	7026	$ 213,467		.5 FTE - $30,000		
State F	1530	$ 46,485				
Subtotal		$ 770,439				
Residential Customer						
State A	755000					
State B	1350000					
State C	235000					
State D	111000					
State E	442673					
State F	104711					
		$ 2,340,242	$ 10,191,000	$390,000		

Table 2

Cost Analysis	Drive Time	Inspect/Document 1st Time	Inspect/Document 2nd Time	Scanners Needed
City gate / DRS	0	$ 60	$ 30	
Industrial on Trans	60	$ 60	$ 30	
Industrial	25	$ 60	$ 30	
Commercial	15	$ 30	$ 15	
Cost for Optical Scanners	$64,000	1 per 4,000 Commercial		

Response: EPA has reviewed this comment and disagrees that the cost estimates of April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) has been underestimated by orders of magnitude. As discussed in response to EPA-HQ-OAR-2009-0923-1016-11, the commenter based its estimated annual inspection cost to use an infrared optical imaging instrument on an assumption that EPA required leak detection and calculation of emissions from customer meters (i.e., industrial, commercial, and residential meters) and from M&R stations at which custody transfer does not occur. The requirements, however, do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps. See preamble Section II.F for a complete discussion about the meters EPA has included in today's final rule. The commenter's assumption therefore resulted in a much larger estimate of compliance costs. Specifically, this assumption accounted for about 99% of the commenter's total estimate, or approximately $37.4 million of the $37.9 million estimated per facility.[101] EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 discusses the costs associated with the meters EPA intended to include in the rule. The remainder of this response discusses the detailed cost estimates submitted by the commenter, as shown in this excerpt (EPA-HQ-OAR-2009-0923-1016-16).

While EPA finds the commenter's estimates of the capital cost of individual pieces of leak detection equipment to be reasonable, the commenter did not provide enough documentation or information to explain the basis for the total annual inspection cost estimates of using infrared optical imaging instruments. Likewise, the commenter did not provide enough documentation or information to substantiate its estimate for the additional resources needed to fulfill the leak inspection requirements ($41 million per LDC). However, EPA considered comments stating that it would be more cost-effective to use alternative leak detection methods. EPA has revised today's final rule to allow alternative options. See preamble Section II.F for details about the alternative leak detection options and see EPA-HQ-OAR-2009-0923-1016-11 for discussion about how this revision affects the costs.

[101] Note: The commenter stated that the cost for single-family residential meters was $23 billion. However, based on the cost per residential meter ($30) and the average number of single-family residential meters (789,758) served by an LDC, as cited by the commenter, the $23 billion estimate seems erroneously too high by several additional orders of magnitude. Using the numbers provided by the commenter results in $23 million, an order of magnitude that is consistent with the commenter's total estimate. Therefore, EPA has assumed this was a typographical error and based its response on the corrected estimate.

Comment Number: EPA-HQ-OAR-2009-0923-1151-108
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Covered Entities (Facilities)

As part of our analysis of the wells per operator in each basin, API also analyzed the number of operators/basin combinations (potentially covered entities) and the number of entities covered under various per well emission assumptions. This analysis determined the following:
- The sum of all operators with operating wells in all basins is 21,744 rather than the 27,993 listed in Table W-2 of the rule preamble.
- As illustrated in the following table the number of covered entities/facilities based on grouping within a basin varies widely based on the assumptions of per well annual emissions.

Covered Entities			
Annual Emissions Metric Tons	5000 (EPA High Estimate)	700 (EPA Mid Range Estimate)	370 (EPA Low Estimate)
IL,IN,KY,PN	895	240	159
Other Basin Total	10,234	2,963	1,637
Total	11,129	3,203	1,796
% of Entities Covered	51.2%	14.7%	8.3%

- Even at EPA's lowest annual emission estimate per well, API's analysis indicates coverage of a larger population of entities under the Basin entity threshold construct. Coupled with the lower number of potentially covered entities from our analysis the percentage coverage is more than double EPA's 4% estimate even at the lowest emission estimate per well.

API Requests

- EPA should reassess their covered entity analysis as part of a broader reassessment of their economic impact analysis and incorporate realistic cost information in the economic impact analysis, as the basis for the rule requirements and preamble

Response: EPA agrees with the commenter that the number of operators/basin combinations should be lower, but disagrees with the commenter's estimate of the covered entities subject to reporting. EPA has reviewed its threshold analysis, based on the HPDI database (used in today's final rule), and found duplicate operators within some basins. This duplication occurred mostly because HPDI collects data from individual States that may record the same operator's name slightly differently, e.g. leading or trailing punctuation in the operator name. For example, *Joe Brown's Oil Company* and *Joe Brown's Oil Comp.* operating in the same basin refer to the same reporter but would have counted as two different reporters because the listed operator names

were slightly different. EPA identified 5,483 such duplicates and has since eliminated the duplicate names from the database. The total number of operators/basin combinations used for the analysis in today's final rule totals 22,510.
Regarding the number of entities likely to meet the reporting threshold, EPA disagrees with the commenter's alternative analysis. The commenter assumed that EPA developed an estimate of annual emissions per well and applied that across operators and basins to determine the number of reporters at the 25,000 Mt CO_2e threshold. The commenter used EPA's estimated individual well pad emissions from the Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027) for the April 2010 proposed rule. EPA estimated individual well pad emissions to analyze coverage at different thresholds for a scenario in which the facility is defined as a well pad. EPA does not agree that this well pad level estimate can be extrapolated to operators/basin combinations. Extrapolating the well pad level estimates requires an inherent assumption that the emissions per well are identical. EPA disagrees with this assumption because the quantity and type of equipment—and therefore the magnitude of emissions—vary by well. Moreover, this assumption is unnecessary because available production data are detailed enough to facilitate analysis by operators. Please see the Section 6 of the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) for more details on EPA's well pad threshold analysis, which uses a completely different methodology than the basin level definition methodology. Also, see Section II.F of the preamble for details about how EPA estimated emissions per well. Hence, EPA's estimate that the rule covered 4 percent of entities in the onshore production segment at the 25,000 Mt CO_2e threshold is appropriate and consistent with the qualified apportionment of emissions discussed in the TSD.

Comment Number: EPA-HQ-OAR-2009-0923-1300-2
Organization: Texas Oil and Gas Association
Commenter: Deb Hastings

<u>Comment Excerpt Text:</u>
EPA must delay inclusion of the Onshore Petroleum and Natural Gas Production Sector in the final rule pending a re-evaluation of the Economic Impact Analysis and rationalization of the rule requirements, rule approaches, burden, and costs vs. the amount of emissions covered
Response: EPA has reviewed all comments on the Economic Impact Analysis and, where appropriate, revised its estimates. See preamble Section III for a summary of the analysis and the Economic Impact Analysis (EIA) (EPA-HQ-OAR-2009-0923) for complete results. Today's final rule allows reporters to request the use of best available monitoring methods under certain conditions, such as lack of service providers and qualified technicians; please see the response to EPA-HQ-OAR-2009-0923-1011-27 for more information.

10.3 COST IMPACTS

Comment Number: EPA-HQ-OAR-2009-0923-1167-52
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

The total estimated first year cost of compliance is approximately \$16,000,000 with an average of about \$8.50/tonne CO_2e. For subsequent years, the estimated total cost of compliance is approximately \$11,000,000 with an average of about \$6.00/tonne CO_2e. Although, as noted in the table, emissions and/or cost estimates were not available for all the emission sources, it is expected that over 90% of the costs are included. It should be noted that companies that have different production field characteristics (e.g. well completions and workovers, compression and dehydration requirements, gas-driven pneumatic device population) would have a different mix of primary emission sources and different cost factors.

Table 1. Estimated Noble Energy Cost to Comply with MRR Subpart W and Subpart C for Onshore Petroleum and Natural Gas Production Emission Sources.

Emission Source	% of US Inv.[A]	NE Costs ($/tonne CO2e)[B]		Notes
		Year 1	Year 2+	
Well Venting for Liquids Unloading [98.233(f)]	24%	$11.00	$9.00	C
Associated Gas Venting and Flaring [§98.233(m)]	12%	$2.00	$1.70	
Gas Well Venting During Unconventional Well Completions and Workovers [98.233(g)]	12%	$1.20	$0.51	
Gas-Fired Reciprocating IC Engines (Combustion)	11%	$2.90	$2.50	
External Combustion: Heaters, boilers	8.4%	$3.70	$2.10	D
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	6.9%	$1.30	$0.19	
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	6.6%	ND	ND	
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	3.9%	$2.60	$0.37	
Dehydrator (glycol) Vent stacks [98.233(e)]	3.1%	$12.00	$10.00	
Components [§98.233(r)]	3.0%	$17.00	$2.401	
Produced Water Dissolved CO2 [§98.233(y)]	2.7%	$21.00	$18.00	E
Production Storage Tanks [98.233(j)]	2.2%	$18.00	$16.00	
Gathering Pipeline Fugitives [§98.233(r)]	1.6%	$46.00	$6.60	
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	0.7%	$43.00	$24.00	
Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	0.7%	-	-	F
Natural Gas driven pneumatic pumps [98.233(c)]	0.6%	$1.50	$0.54	
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	0.1%	ND	ND	
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	0.1%	$49.00	$7.40	
Gas Well Venting During Conventional Well Completions and Workovers [98.233(h)]	0.1%	ND	ND	
Dehydrator (Desiccant) Vent stacks [98.233(e)]	0.1%	ND	ND	
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	0.0%	$38,000.00	$33,000.00	
EOR Injection Pump Blowdown [§98.233(w)]	0.0%	ND	ND	G
Well Testing Venting and Flaring [§98.233(l)]	0.0%	NA	NA	H
Flare Stacks [§98.233(n)]	0.0%	NA	NA	I
Gas Composition [§98.233(u)]		NA	NA	J
TOTAL	**100.0%**	**$8.50**	**$5.90**	

ND – data not available

NA – not applicable

A. Estimated percent of US onshore production GHG inventory from Table 2.

B. 2010 dollars. Data management, calculations, record-keeping, and reporting costs allocated to emission sources proportional to source emission estimation cost.

C. Well Unloading emissions and compliance costs are expected to reduce as more plunger lift operations are automated and optimized.

D. Based on simple "company records" including burner rating and estimated operating hours. Assumed that totalizing flowmeters will ***not*** be installed on all external combustion equipment.

E. Emission estimate based on engineering judgment and assumptions and additional data needed to refine estimate.
F. Minimal compliance costs; emissions based on population emission factor and readily available production data.
G. Based on docket data, 500,000 pumps would be needed to account for about 0.1% of sector GHG emissions.
H. The majority of well tests are conducted while the wells are in operation and do not require flaring. Other well tests would be included in well completion and well workover estimates.
I. Flare emission estimates included in other emission source specific estimates.
J. Cost to collect and analyze gas samples included in Total but not included in costs for individual emission sources.

A review of the cost data in Table 1 shows:
• EPA has drastically underestimated the cost of rule compliance.
- The total estimated first year cost of compliance for Noble Energy alone is approximately \$16,000,000 with an average of about \$8.50/tonne CO2e. Table W-5 of the proposed rule preamble estimates the first year cost of compliance for the ***entire*** onshore production sector to be about \$22,700,000 with an of \$0.18/tonne CO2e. The EPA cost estimate is about a factor of 50 lower than the Noble Energy estimate.

- The total estimated cost of compliance for subsequent years for Noble Energy alone is approximately \$11,000,000 with an average of about \$6.00/tonne CO2e. Table W-5 of the proposed rule preamble estimates the subsequent years cost of compliance for the ***entire*** onshore production sector to be about \$8,600,000 with an of \$0.06/tonne CO2e. The EPA cost estimate is about two orders of magnitude lower than the Noble Energy estimate.

• Very high compliance costs for numerous emission sources indicate alternative, simpler emission estimation methods are needed or that these sources should be removed from the reporting requirements.

- Annual costs for Hydrocarbon Liquids Dissolved CO2 are about \$40,000/tonne CO2e. These costs are a result of this being a very small emission source (as shown in Table 2 below) and the requirement for quarterly sampling of liquid hydrocarbon storage tanks. As discussed below, this is an insignificant emission source to the total inventory.
- Quarterly sampling requirements contribute to the high costs for Produced Water Dissolved CO2 and Acid Gas Removal Vent Stacks. As discussed above, AGRs are an insignificant emission source to the total inventory.

- Extensive process sampling requirements contribute to the high costs for Production Storage Tanks and Glycol Dehydrators.

- Surveying thousands of well sites and annual tracking of new, decommissioned, and divested operations contribute to the high costs for Component and Gathering Pipeline Fugitives. As discussed below, available data indicate Gathering Pipeline Fugitives is an insignificant emission source to the total inventory.

- Direct measurement requirements contribute to the high costs for Reciprocating Compressors Rod Packing Vents and Well Venting for Liquids Unloading. As discussed below, available data indicate Reciprocating Compressors Rod Packing Vents is an insignificant emission source to the total inventory.

Response: Regarding comments that EPA underestimated the costs for onshore production, see preamble Section III.B.2 of today's final rule for EPA's response and discussion about the basis for the cost estimates. See also comment EPA-HQ-OAR-2009-0923-1167-11 for EPA's response to the specific cost estimates presented above. Regarding the commenter's cost issues with monitoring methods, see EPA-HQ-OAR-2009-0923-1151-5, which discusses changes EPA made to the today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component.

Comment Number: EPA-HQ-OAR-2009-0923-1174-8
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

<u>Comment Excerpt Text:</u>
3. Estimated Cost Impact on Oil and Gas Production

As described earlier, Devon has evaluated the economic impact of the proposed Subpart W. We performed a source by source cost analysis using recent equipment counts. Devon's cost estimate for the first year of compliance is nearly $28 million, without contingency.

API's projected industry-wide first year cost estimate exceeds $1.8 billion and is larger than EPA's projection of $27.7 million by a factor of at least 66 times. Although API used a different approach to evaluate costs, there is congruence between Devon's and API's cost projections because we operate approximately 2% of wells in the US and our cost estimate comprises approximately 2% of the cost that API estimates.

Devon is convinced that EPA has significantly underestimated the cost impact and burden of Subpart W. Therefore, EPA should:

* Re-evaluate the Economic Impact Analysis and restructure the rule to simplify the requirements and reduce burden.

* Delay inclusion of the Onshore Petroleum and Natural Gas Production sector. This could be accomplished by developing a phased implementation schedule for Subpart W so that industry sectors with less resource-intensive requirements start reporting sooner and those with more burdensome requirements start reporting later.

* Allow use of best available monitoring methods ("BAMM") for source types requiring metered flow rates or monitoring parameters for calendar year 2011.

Response: EPA disagrees with the cost estimate provided by the commenter; please see comment EPA-HQ-OAR-2009-0923-1174-2 for further details. Also, see comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-106 for detailed explanation of EPA's analysis of API's comments and conclusions that the commenter has cited. Regarding the comment that EPA revaluate the Economic Impact Analysis (EIA) and restructure the rule, see preamble Section III for a summary of the economic impact analysis conducted for today's final rule. Regarding the commenter's cost issues with the monitoring methods, see EPA-HQ-OAR-2009-0923-1151-5, which discusses changes EPA made to the final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component. Finally, regarding the commenter's recommendation to delay implementation of the rule, see Section II.F of the preamble a complete response and discussion about conditions under which reporters may use BAMM.

Comment Number: EPA-HQ-OAR-2009-0923-1011-29
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Preamble at 18618 and 18625.—(KEY ISSUE) El Paso believes that EPA has significantly underestimated the level of effort and cost implications for Subpart W, as it applies to onshore oil and gas production operations. As a result, reporting should be based on a field basis. A detailed cost analysis has been included in Appendix II.

Preamble at 18618 and 18625, Economic Impacts of the Proposed Rule Support Reporting on a Field Basis as Opposed to Cost Prohibitive Basin Approach

El Paso supports commenters, such as the American Exploration and Production Council, who urge EPA to use the traditional definition of facility for oil and gas activities, rather than either the field-level or basin-level approaches proposed. As between field-level and basin-level reporting, El Paso recommends that EPA employ the applicability threshold for exploration and production based on applicable sources located within a reporting field or area that in the aggregate emits over 25,000 metric tons per year. Through this rule development, in determining the appropriate threshold and "facility" definitions, EPA must balance the coverage in terms of emissions with the regulatory and cost burden to both industry and the regulatory agency.

Table W-2, on page 18618 of the preamble, indicates that at a proposed 25,000 metric tons threshold, about 81% of the emissions are covered by employing the applicable facility defined at "basin" level. However, as outlined in Table W-3 on page 18619, EPA concludes that about 55% of the emissions are covered by employing a facility definition at a reporting field level.

El Paso has been unable to reproduce EPA's emissions or cost basis due to lack of information provided in various support documents associated with the rule. The preamble is the first public document where EPA has revised its estimates of the total emissions from the natural gas sector. EPA has not given reasonable consideration or explanation of the costs of including E&P in the monitoring and reporting rule requirements.

El Paso believes that EPA has significantly underestimated the level of effort and cost implications for Subpart W, especially as it applies to onshore oil and gas production operations. However, it is difficult to compare internal estimates of the cost impacts to EPA's assumptions, given that the Economic Impact Assessment (EIA), Technical Support Document (TSD), or information available on the Docket are not consistent with the basin-level facility definition or do not provide sufficient detail to evaluate EPA's cost assumptions. El Paso developed a detailed cost estimate for our E&P operations and the number of sources associated with our upstream operations for two reporting unit scenarios: (1) basin > 25,000 metric tons; and (2) field >25,000 metric tons. The detailed cost analysis has been included in Appendix II. Figure 2 presents estimated costs for El Paso's onshore oil and gas production operations relative to the percent of total emissions and number of regulated fields for each of the three reporting area scenarios. Essentially, 98% of the emissions are covered at the basin level but at over twice the cost of covering El Paso facilities at a reporting field basis.

Figure 2: El Paso's Estimated Compliance Costs for Three "Reporting Area" Scenarios [see original PDF for figure]

A. Basin Reporting Unit >25,000 metric tons CO_2e:

El Paso constructed a detailed cost analysis on a source-by-source basis for all of its operations that exceed 25,000 metric tons CO_2e at the basin level. For the upstream operations only, the proposed rule will require that more than 1 million individual emission sources be measured or documented in order to quantify and report emissions. El Paso has examined the level of effort expected to gather data specified for onshore oil and gas production operations. Our estimates show that first year compliance for Subpart W will require over 25 full time equivalents[102] (FTE). Subsequent years will require 17.1 FTEs. Based on our estimates for the basin-level reporting unit, the emission sources with the largest compliance burden are 10K thresholds.

- Dissolved CO_2: 8.57 FTEs to comply (for both Year 1 and subsequent years);
- General activities to develop data management systems and processes (including training) to gather, report, and monitor the required information: 4.58 FTEs for Year 1, 2.65 FTEs for subsequent years.
- Tanks: 3.75 FTEs for Year 1, 3.21 FTEs for subsequent years.
- Gas well workovers and completions (conventional and unconventional combined): 1.08 FTEs for Year 1 and 0.59 FTEs for subsequent years.
- Well venting for liquids unloading: 1.05 FTEs for Year 1 and 0.62 for subsequent years.
- Reciprocating Compressor Rod Packing Vents: 0.71 FTEs for Year 1, and 0.67 FTEs for subsequent years.

For a reporting unit defined as a basin > 25,000 metric tons CO_2e, El Paso has 9 such basin-level reporting units comprised of 60 E&P fields, with an average first-year cost of $732,713 per basin.

B. Field Reporting Unit >25,000 metric tons CO_2e:

For comparison, El Paso also examined the costs and emissions coverage based on defining the E&P reporting unit at a production field level emitting > 25,000 metric tons CO_2e (these details

[102] FTE based on 2000 hours/year.

are also provided in the cost analysis spreadsheet). This approach captures 65% of emissions from El Paso's E&P operations, but reduces the reporting burden to a total of 15 production fields at an average cost of $206,000 per field. Emissions associated with fields not covered by the provisions of the proposed rule, could be estimated by applying simple emission factors to production rates or estimates of major equipment.

Based on the field level approach and 25,000 metric tons threshold, the estimated first year compliance will require 9.9 FTEs and 7.9 FTEs for subsequent year compliance efforts.

Table 2: Comparison of El Paso and EPA Cost Estimates

	Year 1 Costs/Facility		**Year 2 Costs/Facility**	
	Basin >25k MT/year	**Field > 25k MT/year**	**Basin >25k MT/year**	**Field > 25k MT/year**
Facility Count	9	15	9	15
El Paso	$732,713	$205,650	$546,810	$160,106
EPA	$44,367	No Estimate	$13,691	No Estimate

C. Reporting Level Conclusions and Recommendations:

Based on the detailed cost analysis performed using inventory information rooted in three years of third-party verified voluntary emissions inventories, El Paso supports a production field level approach and 25,000 metric tons CO2e per year threshold. The quality of emissions information gathered would be better for field-level data rather than basin-level data. Characteristics of the produced oil and gas, method of separation and processing are more closely aligned with the field from which the oil and gas is produced than from a broader basin perspective. El Paso has been compiling GHG emission inventories at the field level since 2006, using field designations that are similar to that of the Energy Information Administration. We believe this approach balances both coverage and regulatory and compliance burden.

APPENDIX II

Analysis of the EPA Proposed Greenhouse Gas Mandatory Reporting Rule Cost Impacts for Natural Gas Systems

El Paso reviewed the EPA economic impact analysis for five types of natural gas industry facilities affected by Subpart W of the proposed GHG mandatory reporting rule: (1) onshore production facilities; (2) natural gas transmission facilities; (3) natural gas processing plants; (4) underground storage facilities; and (5) LNG import facilities. The information made available to the public through the rule docket is inadequate for conducting an independent review of EPA's calculations and many of its assumptions that form the basis for the Subpart W cost estimates given in the RIA for onshore production facilities. Nonetheless, El Paso's reviews indicates the first year average cost impact[103] of $18,000 per pipeline transportation of natural gas system facility and $24,000 per E&P facility is underestimated as shown in the following tables.

Table A-1: Total Cost Comparison By Segment

	EPA Estimates		Independent Estimates		Difference	
	Small					
Segment	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total
Onshore Production (Field >10K)	$44,367	$13,691	$144,898	$111,401	69.38%	87.71%
Gas Processing	$12,019	$5,530	$27,758	$22,324	56.70%	75.23%
Transmission	$8,427	$4,825	$17,299	$16,853	51.29%	71.37%
Natural Gas Storage	$11,913	$5,096	$15,320	$14,874	22.24%	65.74%
	Medium					
Segment	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total
Onshore Production (Field >25K)	$44,367	$13,637	$205,651	$160,106	78.43%	91.48%
Gas Processing	$52,105	$11,607	$46,745	$43,155	-11.47%	73.10%
Transmission	$17,081	$8,490	$27,078	$28,342	36.92%	70.04%
Natural Gas Storage	$20,528	$9,153	$24,509	$25,773	16.24%	64.49%
LNG Import	$21,251	$8,921	$20,354	$17,783	-4.41%	49.84%
	Large					
Segment	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total	Yr 1 Total	Yr 2 Total
Onshore Production (Basin >25K)	$44,367	$13,637	$732,713	$546,810	93.94%	97.51%
Gas Processing	$58,966	$13,795	$57,595	$48,870	-2.38%	71.77%
Transmission	$21,910	$10,335	$33,081	$29,009	33.77%	64.37%
Natural Gas Storage	$28,666	$13,572	$30,222	$26,455	5.15%	48.70%

[103] EPA Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Supplemental Rule (GHG Reporting), Final Report, December 8, 2009.

Table A-2: Onshore Production Year 1 Compliance Costs Based on Independent Estimates

Emission Source	Basin @25k Year 1 Labor Costs	Basin @25k Year 1 Capital Costs	Basin @25k Year 1 FTEs	Field @25k Year 1 Labor Costs	Field @25k Year 1 Capital Costs	Field @25k Year 1 FTEs
Cont. Pneumatic Bleed Device	$ 1,058	$ -	0.01	$ 338	$ -	0.00
Low Pneumatic Bleed Device	$ 54,563	$ -	0.36	$ 34,547	$ -	0.23
Pneumatic Pump Venting	$ 42,643	$ -	0.28	$ 24,176	$ -	0.16
AGR Vent Stacks (CO2 only)	$ 2,756	$ 6,300	0.02	$ 2,756	$ 6,300	0.02
Dehydrator Vent Stacks	$ 56,175	$ -	0.37	$ 30,094	$ -	0.20
Well Venting Liquids Unloading (Method 1)	$ 59,063	$ 90,000	0.39	$ 14,766	$ 22,500	0.10
Well Venting Liquids Unloading (Method 2)	$ 99,281	$ -	0.66	$ 65,859	$ -	0.44
Conventional Gas Well Venting Completions/Workovers	$ 75,825	$ -	0.51	$ 62,400	$ -	0.42
Unconventional Gas Well Venting Completions/Workovers	$ 85,500	$ 60,000	0.57	$ 21,375	$ 15,000	0.14
Storage Tanks	$ 562,406	$ 2,142,500	3.75	$ 284,156	$ 1,082,500	1.89
Well Testing	$ -	$ -		$ -	$ -	
Assoc. Well Gas Venting & Flaring	$ 1,500	$ 6,000	0.01	$ 750	$ 3,000	0.01
Centrifugal Compressor Wet Seal Oil Degassing Vent	$ -	$ -		$ -	$ -	
Reciprocating Compressor Rod Packing Vents Compressor Blowdown Valve Leak Compressor Blowdown Vent (Unit Isolation Valve Leak)	$ 106,313	$ 189,000	0.71	$ 54,338	$ 96,600	0.36
Fugitive Sources - component basis	$ 674,886	$ -	4.50	$ 362,586	$ -	2.42
Gathering pipeline fugitives-miles	$ 1,800	$ -	0.01	$ 1,800	$ -	0.01
Coal Bed Methane Produced H_2O Emissions Hydrocarbon Liquids Dissolved CO_2 Produced H_2O Dissolved CO_2	$ 1,285,500	$ 2,100	8.57	$ 649,500	$ 2,100	4.33
General Costs (per field basis)	$ 686,250	$ 303,000	4.58	$ 171,563	$ 75,750	1.14
TOTAL	$ 3,795,518	$ 2,798,900	25	$ 1,781,003	$ 1,303,750	12
Basin/Field Count	9			15		
Compliance Cost/Facility	$ 732,713			$ 205,650		

Table A-3: Onshore Production Year 2 Compliance Costs Based on Independent Estimates

Emission Source	Basin @25k Year 2 Labor Costs	Basin @25k Year 2 Capital Costs	Basin @25k Year 2 FTEs	Field @25k Year 2 Labor Costs	Field @25k Year 2 Capital Costs	Field @25k Year 2 FTEs
Cont. Pneumatic Bleed Device	$ 159	$ -	0.00	$ 51	$ -	0.00
Low Pneumatic Bleed Device	$ 4,365	$ -	0.03	$ 2,764	$ -	0.02
Pneumatic Pump Venting	$ 2,437	$ -	0.02	$ 1,382	$ -	0.01
AGR Vent Stacks (CO2 only)	$ 1,395	$ 6,300	0.01	$ 1,395	$ 6,300	0.01
Dehydrator Vent Stacks	$ 50,925	$ -	0.34	$ 27,281	$ -	0.18
Well Venting Liquids Unloading (Method 1)	$ 37,125	$ -	0.25	$ 9,281	$ -	0.06
Well Venting Liquids Unloading (Method 2)	$ 55,598	$ -	0.37	$ 36,881	$ -	0.25
Conventional Gas Well Venting Completions/Workovers	$ 53,078	$ -	0.35	$ 43,680	$ -	0.29
Unconventional Gas Well Venting Completions/Workovers	$ 36,000	$ -	0.24	$ 9,000	$ -	0.06
Storage Tanks	$ 482,063	$ 2,142,500	3.21	$ 243,563	$ 1,082,500	1.62
Well Testing	$ -	$ -	0.00	$ -	$ -	0.00
Assoc. Well Gas Venting & Flaring	$ 600	$ 6,000	0.00	$ 300	$ 3,000	0.00
Centrifugal Compressor Wet Seal Oil Degassing Vent	$ -	$ -	0.00	$ -	$ -	0.00
Reciprocating Compressor Rod Packing Vents Compressor Blowdown Valve Leak Compressor Blowdown Vent (Unit Isolation Valve Leak)	$ 100,406	$ 189,000	0.67	$ 51,319	$ 96,600	0.34
Fugitive Sources - component basis	$ 67,489	$ -	0.45	$ 36,259	$ -	0.24
Gathering pipeline fugitives-miles	$ 600	$ -	0.00	$ 600	$ -	0.00
Coal Bed Methane Produced H_2O Emissions Hydrocarbon Liquids Dissolved CO_2 Produced H_2O Dissolved CO_2	$ 1,285,500	$ -	8.57	$ 649,500	$ -	4.33
General Costs (per field basis)	$ 396,750	$ 3,000	2.65	$ 99,188	$ 750	0.66
TOTAL	**$ 2,574,490**	**$ 2,346,800**	**17**	**$ 1,212,444**	**$ 1,189,150**	**8**
Basin/Field Count		**9**			**15**	
Compliance Cost/Facility		**$ 546,810**			**$ 160,106**	

Table A-4: Onshore Production Emission Source Counts

Emission Source	Estimated Source Count Basin @25k	Estimated Source Count Field @25k
Cont. Pneumatic Bleed Device	47	15
Low Pneumatic Bleed Device	5,820	3,685
Pneumatic Pump Venting	1,083	614
AGR Vent Stacks (CO2 only)	3	3
Dehydrator Vent Stacks	140	75
Well Venting Liquids Unloading (Method 1)	180	45
Well Venting Liquids Unloading (Method 2)	2,118	1,405
Conventional Gas Well Venting Completions/Workovers (Method??)	1,011	832
Unconventional Gas Well Venting Completions/Workovers (Method??)	120	30
Storage Tanks	4,285	2,165
Well Testing	0	0
Assoc. Well Gas Venting & Flaring	20	10
Centrifugal Compressor Wet Seal Oil Degassing Vent	0	0
Reciprocating Compressor Rod Packing Vents Compressor Blowdown Valve Leak Compressor Blowdown Vent (Unit Isolation Valve Leak)	315	161
Fugitive Sources - component basis	1,079,817	580,138
Gathering pipeline fugitives-miles	2,404	910
Coal Bed Methane Produced H_2O Emissions Hydrocarbon Liquids Dissolved CO_2 Produced H_2O Dissolved CO_2	4,285	2,165
General Costs (per field basis)	60	15

Response:

<u>Overview of Compliance Cost Estimates and Supporting Documentation</u>

EPA disagrees with the comment and has determined that EPA's cost analysis accurately reflects the compliance costs. Regarding the documentation, EPA has made all of the information required to understand and replicate the Agency's cost estimates available to the public by placing it in the docket (EPA-HQ-OAR-2009-0923). The Economic Impact Analysis (EIA) serves as the core document; Section 4 of this document explains how EPA estimated the costs, identifies and discusses underlying assumptions (e.g., number of labor hours assumed for each activity and associated labor rates), and presents the detailed results and cost breakdowns. Also, the EIA explains how EPA incorporated basin-level reporters in the cost model (Section 4.3), breaks out costs specific to the basin-level reporting (see Tables 4-3 and 4-4), and discusses the alternative field-level analysis (Section 5.1.4). The EIA specifies the basin-level approach used for onshore production and Section 5.1.4 of the EIA shows how estimates at the field-level compare with those at the basin-level. Additional, detailed supporting documents, such as the spreadsheets underlying the threshold analysis and cost estimates for basin-level reporters in onshore production, can be found in the docket; e.g., see *Onshore Production Mandatory Reporting Rule Analysis* (EPA-HQ-OAR-2009-0923-0015). In sum, EPA does not agree with the commenter that the information in the TSD, EIA, and other supporting materials in the docket are not consistent with the basin-level facility definition. Rather, the EIA, TSD, and other supporting materials document EPA's analysis at the basin-level for cost estimates.

Consideration of Commenter's Onshore Production Cost Estimates: Field-level and Basin-level

Comparing the compliance costs of a large facility, such as the one represented by the commenter, to the average compliance cost from EPA's analysis is inaccurate and misleading. While average onshore production compliance costs shed light on the costs from a national perspective, they do not accurately reflect the likely costs for larger facilities. For today's final rule, EPA estimated costs for each reporter using actual activity data derived from the HPDI database. The activity data shows an exponential growth in the number of wells and production for higher emitting producers. This means that a small number of reporters are large in size and the rest of the reporters are considerably smaller in size. Consequently, the average cost for all reporters is highly skewed towards the smaller facilities. In fact, the highest individual reporting cost is estimated at $136,791 while the lowest individual reporting cost is estimated at $6,981. This range shows the large potential difference in reporting costs among petroleum and natural gas operators and why a simple average is not an accurate estimate for larger reporters like the commenter.

Nevertheless the commenter's estimated cost still exceeds EPA's maximum compliance cost estimate. EPA has reviewed both the basin and field level cost estimates provided by the commenter. However, the commenter did not provide sufficient details to substantiate the estimate, such as assumptions relating to labor hours required for monitoring, to allow EPA to respond in detail. The commenter provides FTE hours for monitoring each of the emissions sources, but does not provide details about why that many FTEs would be required. Although the commenter did not provide all the relevant details regarding their cost estimate, EPA has reviewed the higher cost elements in the commenter's total estimate and determined that the commenter overestimated the costs for Hydrocarbon Liquids Dissolved CO_2, Produce Water Dissolved CO_2, and Coal Bed Methane Produced H_2O emissions, and Storage Tanks. EPA has surmised that these gross overestimates may have resulted from unclear language in the proposed rule and subsequent misinterpretation with regard to sampling requirements. Please see Section II.F of the preamble for further details and EPA-HQ-OAR-2009-0923-1151-92 for a response to a comment about the sampling requirements.

EPA's Analysis of Basin-level and Field-level Approaches: Emissions Coverage and Costs

Regarding the comments on the basin-level versus field-level reporting, EPA's analysis of national emissions covered under both options shows that the field-level option would result in a significantly lower coverage in emissions reported—57 percent at field-level versus 85 percent at the basin-level for a 25,000 metric tons CO2e threshold—and a higher cost per ton. Therefore, EPA has concluded that basin-level reporting is more cost-effective because the cost *per metric ton* to report under the basin-level definition is lower than under the field-level definition at the reporting threshold. EPA notes that the *total* costs to report under the basin-level definition may be higher but that is because a higher level of emissions are reported. See Section II.D of The April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) for more information about EPA's decision to require basin-level reporting for the onshore production segment.

Compliance Cost Estimates for Other Segments

Finally, for EPA's response to the commenter's estimates for natural gas transmission facilities, natural gas processing facilities, underground storage facilities, and LNG import facilities see the response to EPA-HQ-OAR-2009-0923-1011-27.

Comment Number: EPA-HQ-OAR-2009-0923-1014-5
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:

To the extent that USEPA has concerns about the GHG emissions from those onshore production wells that fall below the 25,000 tpy CO_2e threshold, IOGA-WV notes that various estimation tools are readily available to the agency to calculate these emissions without imposing unnecessarily costly requirements on individual operators. In West Virginia, for example, the West Virginia Department of Environmental Protection maintains a record of the number of active oil and natural gas wells in the state, and operators of these facilities must monitor and report their oil and gas production levels on an annual basis. In addition, as noted in EPA's comments, USEPA operates the Natural Gas STAR Program, which the agency has already used to identify emissions sources and estimate total emissions from the oil and gas sector. From this information, and with the assistance of the various emissions estimation tools and methodologies at USEPA's disposal, the agency should be able to estimate the marginal contribution from these sources to the nation's total GHG emissions without singling out the oil and gas industry to bear disproportionate costs of this proposal.

Response: EPA does not agree with the comment and expects today's final rule to provide the public accurate emissions and inform future policymaking. The alternatives suggested by the commenter, such as voluntary reporting or reliance on existing production data, would not provide complete and comprehensive estimates of facility-level emissions. In particular, the Natural Gas STAR Program does not provide sufficient emissions data to accurately characterize emissions from the entire United States for several reasons. First, Natural Gas STAR Partners represent just over half of the industry operators in terms of throughput. Second, the Partners have usually targeted the most economic reduction opportunities, meaning the emissions reductions reported are skewed towards the higher emitters. Finally, the Partners have not always reported emissions before and after reductions.

Regarding selection of reporting threshold, see Section II.D of the preamble for more on the threshold justification and monitoring requirements. In addition, Section 5 of the Economic

Impact Analysis presents one of the analyses EPA conducted in considering the tradeoff between monitoring costs and level of emissions coverage at various thresholds. For example, the threshold cost-effectiveness analysis shows how the marginal costs and total emissions covered change relative to the 25,000 ton threshold. Finally, EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the Preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1014-7
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:

Regardless of how USEPA defines a "facility" for purposes of Subpart W, IOGA-WV has concerns about the heavy burden that the initial applicability determination will have on potentially affected oil and gas operators. Unlike Subpart C of the agency's mandatory GHG reporting rule,[104] which applies to emissions from stationary fuel combustion sources, sources to which proposed Subpart W may apply cannot conduct a relatively inexpensive, cursory review of the number of units potentially covered by the rule and calculate whether or not monitoring and reporting is required. Rather, USEPA's proposal forces oil and gas operators to conduct a year's worth of monitoring on several systems in order to determine whether the rule is even applicable in the first instance, using the same measurement and/or estimation methodologies that would apply to future monitoring in the event that Subpart W ultimately is found to apply. Unlike other industrial sectors, because oil and gas systems generally have not been subject to such extensive monitoring requirements for their GHG emissions, many potentially covered entities do not yet have GHG monitoring capability already in place. As such, determining whether Subpart W applies---·and, in the event that the rule does apply, implementing its various monitoring requirements-will constitute a significant departure from current practice and will require the investment of considerable time and resources. Indeed, in addition to the expenses associated with the purchase and installation of this equipment, in many eases even assessing the applicability of the proposed rule would require addition of staff to install, maintain and monitor all of the systems covered by Subpart W. As discussed above, IOGA-WV has serious concerns that the sheer expense associated with conducting this monitoring-even if only for purposes of determining Subpart W's applicability-will result in the premature capping, plugging and abandonment of these small or marginal wells, which could have devastating effects on well owners, as well as employees, their families, and local communities that depend on them. The omission of a less burdensome screening measure undermines the administrative and cost benefits that USEPA has sought to achieve by selecting its 25,000 tpy CO_2e reporting threshold in the first instance.

[104] See 40 CFR. § 98.2(a)(3)(ii) (providing that those facilities containing stationary fuel combustion units, but no source in any other source category covered by the mandatory reporting rule, are not required to report their GHG emissions if their aggregate maximum rated heat input capacity from all stationary fuel combustion units is less than 30 mmBtu/hr).

For these reasons, IOGA-WV recommends that USEIA consider a capacity-based threshold or other less costly emissions estimation methods or tools that would allow oil and gas operators to determine whether the reporting requirements of proposed Subpart W apply. Such an approach would simplify the applicability determination to minimize the burden of proving that a facility is below the 25,000 tpy CO_2e threshold. Any initial applicability determination methodologies can be separate from those methodologies required for actual emissions reporting by covered entities.

Response: EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule. EPA does not agree that reporters will require significant investment to comply with Subpart W, however. Please see EPA's response to EPA-HQ-OAR-2009-0923-1151-107 for further details; EPA's response to EPA-HQ-OAR-2009-0923-1151-5 discusses changes EPA made to today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component; EPA has allowed the use of best available monitoring methods for certain sources to further reduce burden, please see the response to EPA-HQ-OAR-2009-0923-1011-27 for more information; EPA-HQ-OAR-2009-0923-1005-7 discusses marginal wells along with EPA-HQ-OAR-2009-0923-0053-1. Also, please see EPA's response to EPA-HQ-OAR-2009-0923-1303-2 for a discussion about Subpart W's impact on the greater economy.

Comment Number: EPA-HQ-OAR-2009-0923-1015-1
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

<u>Comment Excerpt Text:</u>

EPA has grossly underestimated the cost of implementation for this reporting rule. According to EPA's guidance, staff activities and labor were taken into consideration when drafting the proposed rule. However, if the required sources to report remain aggregated by basin, the number of affected facilities as well as travel to those affected facilities in remote areas does not appear to have been taken into consideration; nor has the GHG emissions from vehicles traveling to remote locations been taken into consideration. Furthermore, the EPA's cost estimation assumes that staff exists on-site to assist with GHG reporting implementation: the opposite is true. Many operators will be forced to hire additional temporary staff or utilize consultants to review and compile data from various divisions in order to determine if Yates is indeed in compliance with the proposed rule.

In the Preamble (page 18610 of the Federal Register), the EPA states "This proposed supplemental rule incorporates a number of changes, including, but not limited to, different methodologies that provide improved emissions coverage at a lower cost burden to facilities than would have been covered under the initial proposed rule, the inclusion of onshore production and distribution facilities" While the original proposed rule called for reporting of 24 emission source types, and this rule requires only 21, the EPA has lumped different types of pneumatic pumps into more general categories, removed wet seal degassing and lumped fugitives into one general category thereby resulting in a reduction in the number of reportable sources. Also, we concede that the original proposed rule required direct measurement of fugitives and other sources using HIVOL sampling, bagging, etc… However, the newly proposed rule includes reporting requirements for many smaller sources that have limited or no emission data that were not previously addressed as well as wellhead activities by basin and pipeline/gathering fugitives. EPA is still requiring direct measurement of many of these sources, which is costly and time consuming, and remains significant for operators to comply.

Response: EPA does not agree with the comment. While this commenter did not provide an alternative cost estimate, EPA has analyzed other commenters' cost estimates for onshore production and determined that they are too high. A detailed analysis is available in EPA's responses to comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment.

Regarding the comment about source coverage, EPA's analysis shows that sources subject to reporting under Subpart W release more than 80 percent of the emissions from the petroleum and natural gas industry but comprise only 20 percent of total sources in the industry. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) for further discussion on source selection. Nevertheless, EPA has responded to concerns about the burden to inventory geographically dispersed equipment leak emission sources and modified today's final rule requirements; see Sections II.C and II.F of the preamble (EPA-HQ-OAR-2009-0923) for a discussion of changes EPA made in monitoring requirements for onshore production. Regarding commenter's assumptions about travel costs and about hiring additional staff or using consultants to "determine if Yates is indeed in compliance with the proposed rule," see EPA's response to EPA-HQ-OAR-2009-0923-1060-1. EPA has reduced the direct measurement requirements for onshore production. Please see Section II.E of the preamble to today's final rule for changes made to today's final rule. Also, please see EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for why EPA has retained direct measurement for some sources.

Comment Number: EPA-HQ-OAR-2009-0923-1024-39
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:

Comments on the Economic Impact Analysis. Kinder Morgan believes that EPA's Economic Impact Analysis (EIA) of the proposed Subpart W significantly underestimates compliance costs for the onshore petroleum and natural gas production source category and unrealistically assumes that facilities with emissions less than 25,000 metric tons CO2-e will not have any compliance costs. The effort for entities in the oil and natural gas sector to determine which facilities meet the reporting threshold of 25,000 metric tons CO2-e per year is completely over looked.[105] Since the proposed Subpart W provides no simplified or streamlined method for determining the applicability of the rule to a given facility, Kinder Morgan would need to perform a full Subpart W emissions assessment on almost all of its facilities in order to make certain that it is in full

[105] 40 C.F.R. SECTION 98.2(b) requires reporting facilities, including facilities that would be subject to the proposed Subpart W, to apply the methodologies set forth in each Subpart to determine whether the reporting threshold is met.

compliance with the Mandatory Reporting Rule. For most facilities, such a screening assessment may be required almost every year. Yet the EIA for the proposed Subpart W computes the overall cost of the rule based on the assumption that 91% of facilities in the petroleum and natural gas sector will be permanently excluded from the scope of the rule.[106] This is an unrealistic assumption that results in the gross understatement of the cost of the rule. EPA cannot assume the costs of making applicability determinations are zero. Even with a simplified screening mechanism, there will be significant effort associated with measurements at those facilities which are above any screening level and below the reporting threshold.

The industry structure and costs summarized in Tables W-9 and W-10 in the preamble of the proposed Mandatory Reporting Rule use NAICS codes incorrectly. For example, onshore natural gas processing plants fall under NAICS code 211112, and should not be lumped together with onshore natural gas gathering compression under NAICS code 486210. LNG storage and import and export equipment fall under NAICS code 486210, not crude petroleum and natural gas extraction NAICS code 211. This mischaracterization of the industry structure through incorrect application of NAICS codes may be diluting the onshore petroleum and natural gas production cost impacts resulting in underestimating costs on a per entity basis.

For those facilities that are clearly above the reporting threshold, Kinder Morgan believes that EPA has significantly underestimated the cost of the proposed Subpart W. The American Petroleum Institute (API) performed a careful inventory of the costs associated with the proposed Subpart W for the onshore petroleum and natural gas production sector alone, and determined that this sector would incur a first-year cost of approximately $1.68 billion, about sixty times EPA's estimate of $28 million. Building an inventory of well site components alone would cost the industry $133 million, according to API. Of particular concern to Kinder Morgan is API's assessment that the proportion of onshore petroleum and natural gas production facilities covered by the proposed rule is much higher than the 4% figure cited by EPA in the preamble to the proposed rule.

Kinder Morgan's own work with the proposed Subpart W has confirmed that the EIA cost estimate is unrealistically low. Once the proposed rule was published, Kinder Morgan began a series of field tests to explore the feasibility of implementing the proposed requirements. Based on those field tests, Kinder Morgan has concluded that the cost per facility to conduct monitoring in compliance with the proposed Subpart W for natural gas compression sector is over $14,000 per facility which includes the cost paid to contractors for labor and rental of the manlift and other equipment. This burden would be incurred by Kinder Morgan alone for more than 200 facilities at a cost of over $3 million to determine applicability under the reporting threshold. Importantly, this cost estimate reflects only ongoing year-to-year expenses associated with Subpart W, and does not include the first-year costs associated with installing meters, training personnel, and establishing data collection and quality control systems. In addition, EPA's cost estimates do not appear to recognize that the installation of meters at many individual components will require costly shutdowns of equipment.[107] EPA's cost estimate also fails to

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[106] EIA at p.4-10 (Table 4-6).

[107] In part for this reason, Kinder Morgan recommends that EPA allow "best available data" to be supplied for the first year of reporting (explained further below).

evaluate the economic impacts that could result from service interruptions that could arise from the requirement to monitor at three operational modes. Considering that EPA chose not to finalize the original Subpart W in part because of the high industry burden it would have imposed,[108] EPA must include these costs when considering if and how to finalize Subpart W.

Kinder Morgan notes that EPA appears to have erroneously applied NAICS codes to affected facilities and sectors in Table W-10 of the preamble when calculating cost-to-sales impacts of the proposed Subpart W. For example, natural gas processing facilities belong to the three-digit NAICS code 211, whereas Table W-10 has classified them under NAICS code 486210 (pipeline transportation of natural gas). It is also not clear whether LNG import, export, and storage should be included in NAICS code 211 (crude petroleum and natural gas extraction), since these activities are more closely related to natural gas transportation. Because the NAICS classification of facilities in Table W-10 affects EPA's calculated cost-to-sales ratios for different segments of the petroleum and natural gas industry, it is important for EPA to ensure that these facilities are assigned the proper NAICS code in its economic analysis.

Even putting aside the costs not included in EPA's economic analysis, Kinder Morgan believes the costs of Subpart W are still disproportionately high relative to other Subparts and industries. Kinder Morgan notes that the first-year cost of the proposed rule ($0.21 per ton CO2-e across all industry segments)[109] would be about seven times higher than the estimated first-year cost of approximately $0.03 per ton CO2-e for the final Mandatory Reporting Rule as a whole.[110] In subsequent years, EPA projects that the cost of reporting under the proposed Subpart W would decline to $0.08 per ton of CO2-e [111], which is still over twice as high as the first-year cost of the Mandatory Reporting Rule. Given that even EPA's overly optimistic EIA found that the proposed Subpart W would be disproportionately costly, Kinder Morgan urges EPA to consider the above recommendations to minimize the costs of the proposed rule, including, for example, establishing a screening tool to determine the applicability of the rule to individual facilities.

Response: EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.

<u>Percentage of Facilities Covered</u>

However, EPA disagrees with the commenter's characterization of EPA's assumption regarding percentage of facilities covered. Please see EPA-HQ-OAR-2009-0923-1151-108 for EPA's response to API's conclusion that the onshore petroleum and natural gas production facilities covered by the rule would exceed 4 percent of facilities nationwide.. In addition, the Economic Impact Analysis did not assume any reporter would be "permanently excluded" from the reporting program. Rather, EPA used best available information to estimate the number of

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[108] See Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56,260, 56,319 (Oct. 30, 2009).

[109] Proposed Subpart W, 75 Fed. Reg. at 18,625.

[110] See Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. at 56,363.

[111] Proposed Subpart W, 75 Fed. Reg. at 18,625.

facilities likely to meet the reporting threshold, and then used that information to estimate monitoring and reporting costs. EPA expects entities that did not meet the reporting threshold to incur the determination costs discussed in Section 4 of the Economic Impact Analysis (EIA) for today's final rule found in docket (EPA-HQ-OAR-2009-0923).

Compliance Cost Estimate

EPA also disagrees with the comment that the cost estimated by the Agency is unrealistically low for the compression sector. First, as described in preamble II.F, EPA has modified today's final rule so that it does not require reporters to install meters that would necessitate equipment shutdowns. This modification reduces burden while maintaining data quality. Second, as described in preamble II.D, EPA clarified today's final rule to allow reporters to conduct an annual measurement of each compressor in the mode as it exists at the time the annual measurement is taken, with shutdown depressurized mode monitored for each compressor at least once every three each years. EPA has also revised today's final rule for onshore production reciprocating and centrifugal compressors to use emission factors for calculating emissions, rather than an annual measurement. Please see "Compressor Modes and Threshold" in EPA-HQ-OAR-2009-0923.

Furthermore, EPA is unable to evaluate the commenter's compliance cost estimate of $14,000 per facility because insufficient documentation was provided to explain how this figure was calculated. For example, the commenter did not provide assumptions for the labor rate(s), labor hours, or a detailed labor description used to calculate the estimated burden. Regarding the American Petroleum Institute (API) cost estimates referenced by the commenter, EPA has provided detailed responses to API explaining why their estimates are too high; see EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107 for further details. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment. EPA estimates the compliance costs per facility in the first year and subsequent years as $27,084 and $7,088 respectively. EPA's estimates include costs for registration; regulation review; monitoring plan development; equipment; training; monitoring & measurement; documentation; reporting; auditing; and archiving.

Regarding the comment about the burden for making a reporting determination, EPA concluded that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule. EPA estimated determination costs for non-reporters well below the threshold to use screening tools as well as the higher burden for those entities that are close to, but do not exceed the reporting threshold, that will supplement the screening tools with preliminary monitoring. Please see Section 4.4 of the Economic Impact Analysis for a detailed discussion of these costs.

In addition, today's final rule allows reporters to request the use of best available monitoring methods under certain conditions, such as lack of service providers and qualified technicians; please see the response to EPA-HQ-OAR-2009-0923-1011-27 for more information.

Incorrect NAICS Codes

Finally, EPA agrees with the comment that the proposed analysis listed incorrect NAICS codes for processing and liquefied natural gas and has since corrected the analysis to include processing under NAICS code 211 and LNG under 48620. However, EPA disagrees that this error resulted in incorrect estimates of the cost impacts or that it underestimated the costs. EPA developed the costs per facility per segment independently and prior to allocating segments to NAICS codes. That is, EPA aggregated the costs by NAICS code *after* the costs were estimated within each segment on a facility-basis. The results of the screening analysis to determine whether today's final rule would have a significant impact on a substantial number of small entities also show that the NAICS error did not cause an incorrect conclusion. The analysis for today's final rule, which assigned costs to the correct NAICS codes, resulted in the same conclusion as the proposal—the rule will not have a significant economic impact on a substantial number of small entities. See Section 5 of the Economic Impact Analysis for complete details and results.

Comment Number: EPA-HQ-OAR-2009-0923-1031-11
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
EPA has significantly underestimated the burden to industry to obtain the information to calculate the emission estimate for gathering pipelines. It is also noted that the emission factor for the gathering pipeline segments (2.81scf/hour/miles) is derived from an unexplained total pipeline emission estimate of 6.6 Bscf. See TSD at 147-148. Anadarko suggests that if EPA has already established this emission estimate, they should simply add it to the rolled-up GHG inventory for the natural gas industry rather than requiring operators to expend significant resources re-creating the exact same number.
Response: EPA disagrees with the commenter on the burden associated with estimating emissions from gathering pipelines; the April 2010 proposal required reporters to so a simple calculation (multiply the number of miles of gathering pipelines by the emissions factor provided in the proposal). However, these costs are not relevant to today's final rule because EPA does not require the reporting of emissions from gathering pipelines and boosting stations. See Section II.F of the preamble for discussion about why today's final rule does not include gathering pipelines and boosting stations.

Comment Number: EPA-HQ-OAR-2009-0923-1031-5
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
The rule would be far more costly than EPA predicts. Anadarko has worked in conjunction with the API and GPA to develop an estimate of the cost of compliance with the

proposed rule for the upstream and midstream sectors. Anadarko concurs with and incorporates by reference the cost estimates provided in API and GPA's comments to the proposed Subpart W.

API analysis shows that total costs for the upstream sector will range from $1.8 to 3.5 billion per year, as compared with EPA's estimate of about $28 million per year for the upstream sector. API's analysis shows that EPA's estimate is over two orders of magnitude low. Further, API's analysis only concentrated on the upstream sector and did not include midstream sector costs.

GPA evaluated the economic impact for the midstream sector. That analysis shows that total costs for all gas plants would exceed $698 million while the total costs to gathering/booster stations in the midstream sector would exceed $3.8 billion for the initial reporting year.

It is clear that EPA has failed to recognize the full impact of requiring reporting at all facilities and pipelines in the upstream and midstream sectors. EPA should delay the final rule pending a re-evaluation of the Economic Impact Analysis and rationalization of the rule requirements, rule approaches, burden, and costs versus the amount of emissions covered. These analyses show that EPA can and should significantly simplify and streamline reporting requirements for the upstream and midstream sector, and we urge EPA to do so for all the reasons set forth in these comments.

Response: Regarding the American Petroleum Institute (API) cost estimates referenced by the commenter, EPA has provided detailed responses to API explaining why their estimates are too high; see EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107 for further details. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment.

Regarding the commenter's estimates for the midstream sector and the GPA cost estimates, please refer to EPA-HQ-OAR-2009-0923-1151-107 and EPA-HQ-OAR-2009-0923-1206-25 respectively. EPA has assessed the commenter's concerns about the processing segment and has 1) clarified specific requirements for reporters; 2) removed the requirement to report emissions from gathering lines and booster compressor stations and 3) modified methodologies in a number of areas, such as the monitoring of compressors in all the three modes of operations; please see response to EPA-HQ-OAR-2009-0923-0055-16 and Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1040-8
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

<u>Comment Excerpt Text:</u>

The rule would be far more costly than EPA predicts.

Member companies of AXPC have worked in conjunction with the API to develop an estimate of the cost of compliance with the proposed rule for the upstream sector. AXPC concurs with and incorporates by reference the cost estimates provided in API's comments to the proposed Subpart W. This analysis shows that total costs for the upstream sector will range from $1.8 to 3.5 billion per year, as compared with EPA's estimate of about $28 million per year for the upstream sector.

API's analysis shows that EPA's estimate is over two orders of magnitude low.
It is clear that EPA has failed to recognize the full impact of requiring reporting at all facilities in the onshore petroleum and natural gas production sector. API's analysis shows that EPA has significantly understated the cost and burden of Subpart W as they are significantly higher than EPA projected. AXPC requests that EPA re-evaluate the costs associated with this rule, and should significantly simplify and streamline reporting requirements for this sector.
Response: EPA disagrees with the comment. Regarding the American Petroleum Institute (API) cost estimates referenced by the commenter, EPA has analyzed those cost estimates and determined that they are too high. A detailed analysis is available in EPA's responses to comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment. These references also discuss changes made to the rule to reduce burden; see Section II.E of the preamble to today's final rule for a comprehensive summary of the changes made to today's final rule. Finally, EPA reviewed its Economic Impact Analysis (EPA-HQ-OAR-2009-0923) and updated it to reflect changes in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1060-29
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
In the Preamble (page 18610 of the Federal Register), the EPA states "This proposed supplemental rule incorporates a number of changes, including, but not limited to, different methodologies that provide improved emissions coverage at a lower cost burden to facilities than would have been covered under the initial proposed rule, the inclusion of onshore production and distribution facilities" While the original proposed rule called for reporting of 24 emission source types, and this rule requires only 21, the EPA has lumped different types of pneumatic pumps into more general categories, removed wet seal degassing and lumped fugitives into one general category thereby resulting in a reduction in the number of reportable sources. Also, we concede that the original proposed rule required direct measurement of fugitives and other sources using HIVOL sampling, bagging, etc. However, the newly proposed rule includes reporting requirements for many smaller sources that have limited or no emission data that were not previously addressed as well as wellhead activities by basin and pipeline/gathering fugitives. EPA is still requiring direct measurement of many of these sources, which is costly and time consuming, and remains significant for operators to comply.

Response: EPA disagrees with this comment; please see EPA's response to EPA-HQ-OAR-2009-0923-1015-1 for discussion about EPA's basis for determining which sources to include in the rule as well as revisions to today's final rule that reduce monitoring burden..

Comment Number: EPA-HQ-OAR-2009-0923-1151-100
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:

Section 98.233(n): Flare Stacks: For flaring associated with well testing and the potential for flaring emissions from dehydrators, unconventional well workovers and completions, and tanks, the rule points to the calculation methods for flare stacks.
* For flaring associated with well testing, API assumed each gas well covered by the rule is tested one time per quarter. The vast majority of well tests are conducted while the wells are in operation and do not require flaring. As a result, API assumed 0.1% of the estimated 1,500,000 annual well tests were flared. Based on 1 hour to determine the GOR for each well, and $100 per hour, results in a projected cost of $150K.
* No additional costs were assigned to flaring associated with dehydrators, unconventional well workovers and completions, and tanks. For each of these sources, costs were estimated for venting emissions from these sources (discussed previously). The flare equations would apply the same volume estimates. Data management, which is addressed separately for all of the OPGP sources, is the only cost that would apply to flared sources.

Response: The commenter's estimated cost per well ($100) for testing and flaring is slightly higher than EPA's estimate per well (approximately $71). The difference in costs per well results from different assumptions about labor rates. EPA assumes one hour for a junior engineer to perform an emissions calculation with GOR measurement at a $71 per hour labor rate. Please refer to Section 4 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for how EPA determined labor rates for the oil and gas industry. EPA cannot respond further to the commenter's labor rate assumption because they did not provide any information to substantiate it.
Regarding assumptions about activity data, the commenter assumed a lower number of annual well testing and flaring events (1,500) than what EPA assumed (3,000). EPA based its estimate of 3,000 on the assumption that all wells drilled and completed would flare the gas produced during testing. While EPA's activity data assumption is higher than the commenter's, the difference in national costs under each assumption is minimal—roughly $200,000 assuming 3,000 flarings versus about $100,000 assuming 1,500 flarings.
Today's final rule allows reporters to use available GOR data from the wells being tested. EPA assumes reporters will know this GOR data even in the absence of Subpart W, e.g., to determine well flow rates and fluid characteristics as part of normal operations.

Comment Number: EPA-HQ-OAR-2009-0923-1151-101
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(o): Centrifugal compressor wet seal degassing vents: – API did not evaluate this source category since centrifugal compressors are not often used in production operations.

Section 98.232(c)(16) and Section 98.233(w): EOR injection pump blow-down – API did not evaluate this source category.

Section 98.232(c)(17) and Section 98.233(d): Acid gas removal (AGR) vent stacks – API did not evaluate this source category

Response: EPA appreciates this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-104
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Combustion Units – non portable – Presuming that the natural gas factors in Table C-1 of the rule can be used throughout the Onshore Production Sector, which enables Tier 1 or Tier 2, operators would be required to track the run time and load (company data) for each individual combustion unit in order to calculate fuel volume and hence emissions. If Table C-1 factors cannot be used, then the industry would be faced with Tier 3 metering which would impose astronomical time and cost burdens which are not evaluated further. Partially based on EPA's 2008 Inventory of U.S. Greenhouse Gas Emissions and Sinks Table A-118, API estimates a population of some 526,627 individual combustion units subject to the rule in the OPGP Sector. These are comprised of the following: (1) Fired Separators = 307,734; (2) Other Heaters = 141,736; (3) Dehydrator Regeneration Heaters = 33,907; (4) Compressor Engines = 34,047; and (5) Other Engines = 10,203. Despite the typically small size of the heaters (~0.3 MMBTU average) and engines in the OGPG sector, the same "company data" will need to be tracked, QA/QC'd, and used to generate fuel volume use and hence emission estimates, as required for combustion units at discrete facilities meeting the 25,000 metric ton threshold in the original rule. Assuming half hour per combustion unit to track and collect "company data", perform adequate QA/QC, and calculate emissions at a rate of $100 per hour the total cost is estimated as $26.3 MM for this source category.

Response: The commenter has raised two issues about combustion emissions: use of the appropriate method to calculate CO_2 emissions (i.e., the Tier methodologies specified in Subpart C) and the associated burden to estimate fuel volumes. Regarding the use of appropriate method, EPA did not intend for Subpart W to require reporters to use either Tier 3 or Tier 4 to report combustion emissions from onshore production. Therefore, EPA has clarified today's final rule to require onshore production reporters to use either Tier 1 or 40 CFR 98.233(z), which is a method in Subpart W similar to Tier 1, to estimate and report their combustion emissions. EPA expects that onshore production reporters who combust fuels that are not listed in Table C-1 (e.g., field gas), and therefore not eligible for Tier 1, to use the method in Section 98.233(z) to estimate and report emissions from combustion sources.

EPA agrees that the proposed requirement to monitor all combustion equipment in onshore production would be burdensome. Therefore, the major combustion equipment subject to reporting under today's final rule includes compressor/ generator engines and drilling rigs. Today's final rule does not require reporting of emissions from external combustion units that have heat capacity of 5 MMBtu per hour or lower. Instead, reporters will provide only an activity count for external combustion equipment (fired separators, heaters, and dehydrators) at or below 5 MMBtu per hour. EPA notes that the cost estimate for Subpart W *process* emissions, specifically estimating major equipment leaks, assumes reporters do an activity count and therefore also captures the burden for external combustion units to do these activity counts. Furthermore, EPA has determined that nationally almost all of the heater/treaters, fired separators, and dehydrators fall below the 5 MMBtu per hour equipment threshold; hence there is no burden to report from these sources.

EPA has determined that the combustion cost estimates for the April 2010 proposal, which are used in today's final rule as well, account for the monitoring and reporting burden associated with onshore production equipment. The April 2010 combustion cost estimate assumed that reporters would use the Tier 1 methodology or its equivalent and therefore incorporated labor assumptions that were not specific to a particular industry segment. In response to the comments and final rule changes, EPA used assumptions tailored to the onshore production segment to estimate the costs for them to determine fuel consumption at compressor engines and drilling rigs. Given that compressor engine fuel consumption can be determined using heat rate and operating time of the equipment, EPA assumed that an operator would spend 10 minutes collecting these data for each unit. For drilling rigs, operators can collect fuel consumption information from their contractors, who typically drill and complete the wells and therefore know how much fuel the equipment consumes. EPA has therefore assumed 30 minutes will be sufficient to determine the fuel consumption for each drilling event. The combustion estimates resulting from these tailored assumptions are lower than the estimates relying on assumptions relevant to a broader array of industry segments; see the memo, "Additional Analysis of Combustion Costs for Onshore Production," for the detailed analysis and results (EPA-HQ-OAR-2009-0923). EPA has decided, however, to retain the higher estimate in order to provide a more conservative estimate of combustion-related costs. See Section III.A of the preamble to today's final rule for further discussion about the estimation of combustion costs.

Comment Number: EPA-HQ-OAR-2009-0923-1151-105
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(z): Portable equipment combustion emissions - Presuming that EPA requires reporting of portable combustion units in the final rule (issues associated with these requirements are outlined in Section III, comments 7, 12, and 41), the use of Tier 1 methodologies should be allowed for this source category. API's analysis estimates some 317,926 potential portable combustion units subject to the rule in the OPGP Sector. Although only a subset of these would be located at an individual well-site (well head) for more than 30 days in a year, operators would still have to track each instance and gather "company records" for each portable combustion unit from their owners to later determine if they had exceeded the 30 day time limit and were subject to reporting. Estimating 2 hours total to track each portable combustion unit instance, obtain fuel and BTU input information from the owner, obtain run hours and load or fuel use from the owner, QA/QC the information, and calculate fuel use and emissions for each unit at a rate of $100 per hour yields a total cost of $31.8 MM for this source category.

Response: First, EPA has modified today's final rule such that reporters should not need to track equipment operating at non-reporter facilities. Specifically, EPA has removed the 30-day time limit for portable combustion units; reporters will provide information about equipment regardless of the duration of time each unit stays in one place. See response EPA-HQ-OAR-2009-0923-1170-7 for further details. Second, EPA disagrees with the labor assumptions and costs presented in the comment. The commenter has applied the labor hours, including fuel use tracking, BTU content, etc., to the entire population of portable combustion units (371,926) and not the subset actually subject to reporting, which results in the unreasonably high $31.8 million burden. See EPA's response to EPA-HQ-OAR-2009-0923-1151-104 for details about on EPA revisions to combustion emissions reporting from onshore production and labor assumptions. Note that the requirements for portable equipment are the same as those for non-portable equipment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-106
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Data Management System Set-up and Data Entry: To adequately manage the massive amounts of data required by the rule and enable QA/QC, emissions calculations, reporting and recordkeeping, each covered entity will have to set-up some type of data system. A cost range was examined, with a low range cost of $100,000 per data system for a reporting company that is adding the calculation elements for the rule into an existing system, and a high cost range of $850,000 for a reporting company that has to implement a data management system to handle the required information. Using EPA's estimate of 1,232 covered entities, this yields a cost range of $123.2 MM to $1.05 B. Entering the required date into these systems is estimated to cost an additional $47 MM for a total cost range of $169 MM to $1.1 B.

Response: EPA disagrees with the comments on both the data reporting software needs as well as the associated costs. As discussed in Section III of the preamble to today's final rule, EPA does not require the use of any data management software in today's final rule; it is at the discretion of reporters to buy one for their own convenience. Accordingly, EPA's analysis focuses on the activities and equipment required to fulfill today's final rule's requirements. Section III of the preamble to today's final rule summarizes the basis for EPA's disagreement with this comment. The remainder of this response provides additional details underlying EPA's analysis of this comment.

First, the estimate of 1,232 reporters cited by the commenter represents a combination of operators and basins. EPA has estimated that under today's final rule that there will be 981 reporters for onshore production, which represents 557 unique operators. Approximately 92 percent of these 557 unique operators have a limited presence in one to three basins, as follows: 428 operators will report from one basin only; 59 from two basins; and 25 from three basins. The remaining 8 percent (45 operators) operate in more than three basins. Although the operators with a presence in more than three basins may have greater data management needs, they can effectively use spreadsheet and database software because the monitoring methods require a one-time data collection, not a continuous data collection that might warrant complex data management software. EPA has therefore concluded that operators subject to the rule do not need sophisticated or customized data management software to monitor and report emissions from their limited operation size; they can effectively do that using spreadsheet and database software in common use (such as MS Excel® and MS Access®).

Although not required under the rule nor viewed necessary by EPA, reporters may use customized software packages for data collection. Reporters, for example, may use the SANGEA® software, which has been available for over a decade and free of charge, to accommodate the rule data collection requirements. EPA has found that major oil and gas operators already use software programs like SANGEA® that can be adapted to accommodate the data collection requirements for this rule.

Also, consideration of the unique number of reporters is key because those who choose to develop or purchase a data collection system will likely obtain one for all of the basins in which they operate, not one for each of the basins for which they report.

In sum, EPA determined that the commenter's cost estimate is much higher than the data management software that may be considered by reporters. Although the commenter did not provide any information about the software represented in its analysis (except for cost), a system in the price range assumed by the commenter is usually customized to accommodate data needs that extend far beyond the scope of this rule. See Section III.B of the preamble to today's final rule for further discussion. EPA concluded that the Economic Impact Analysis presents a realistic estimate of the costs to collect and manage data under today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-107
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
API Cost Estimate Summary: As the following table illustrates, API's projected burden and costs for the Onshore Petroleum and Natural Gas Production sector under the proposed rule exceed $1.83 billion and are larger than EPA's projection of $27.7 MM by a factor of at least 66 times. API's alternative cost estimate is not inclusive of all sources (e.g., acid gas removal) and applies conservatively low estimates for many cost elements, such as meter costs, analytical costs and labor time. Even with these conservative assumptions, the cost per metric ton of CO2 equivalent emissions from API's analysis exceeds $8.17 vs. EPA's estimated $0.18 per metric ton in Table W-5 of the preamble.

Onshore Petroleum and Natural Gas Production	
Source Category or Activity	**API Projected Cost $MM**
Well Site Inventory	$133.4
Ancillary Facility Inventory	$2.0
Well-bore Configuration Inventory	$33.3
Dehydrators	$24.6
Hydrocarbon Tanks	$192.3
Hydrocarbon Liquids Dissolved CO2 - Low	$281.4
Hydrocarbon Liquids Dissolved CO2 - High	$791.4
Produced Water Dissolved CO2	$600.1
Reciprocating Compressors Rod Seals - Low	$20.3
Reciprocating Compressors Rod Seals - High	$33.0
Pneumatic Pumps	$52.0
Well Venting for Liquids Unloading - High (Method #1)	$117.9
Well Venting for Liquids Unloading - Low (Method #2)	$58.5
Unconventional Well Completion and Work-over - High (Method #1)	$15.0
Unconventional Well Completion and Work-over - Low (Method #2)	$7.6
Conventional Well Completion and Work-over	$2.1
Associated Gas Venting and Flaring	$0.1
Well Testing Flaring	$0.1
Centrifugal Compressor Wet Seal Degassing Vents	Not Analyzed
EOR Injection Pump Blow-down	Not Analyzed
Coal Bed Methane Produced Water	Included in produced water dissolved CO2
Combustion Units - non portable	$26.3
Combustion Units - portable	$31.8
Data Management - Low Estimate (Method #1)	$169.4
Data Management - High Estimate (Method #2)	$1,096.1

Onshore Petroleum and Natural Gas Production	
Source Category or Activity	**API Projected Cost $MM**
Total - Low estimates	**$1,635.3**
Total - High estimates	**$3,151.5**
Overhead and Management (@12%) - Low Total	$196.2
Overhead and Management (@12%) - High Total	$378.2
Total - Low estimates w/overhead	**$1,831.6**
Total - High estimates w/overhead	**$3,529.7**
EPA 's Cost Estimate	**$27.7**
Ratio - API Low estimates to EPA	**66**
Ratio - API High estimates to EPA	**127**
EPA Emissions Covered MM MT's CO2e (Preamble Table W-2)	**224**
EPA Initial Year Cost per MT CO2e	**$0.12**
API Initial Year Cost per MT CO2e - Low Case	**$8.17**
API Initial Year Cost per MT CO2e - High Case	**$15.74**

Response: Except as noted below, EPA disagrees with this comment and has determined that the commenter's cost estimates are too high. See EPA's responses to the following comments for detailed explanation of EPA's analysis and conclusions:

- EPA-HQ-OAR-2009-0923-1151-89: for response to commenter's estimates of the number of wells and total emissions covered; the costs to inventory well and non-well sites; costs for well bore configuration; assumptions about travel to the sites; and the costs to make reporting determination
- EPA-HQ-OAR-2009-0923-1151-90: for response to the commenter's cost estimate for dehydrator units
- EPA-HQ-OAR-2009-0923-1151-91: for a response to the commenter's cost estimate for tanks in hydrocarbon liquids service
- EPA-HQ-OAR-2009-0923-1151-92: for response to the commenter's cost estimate for hydrocarbon tanks and the hydrocarbon liquids dissolved CO2 category
- EPA-HQ-OAR-2009-0923-1151-93: for a response to the commenter's cost estimate to sample hydrocarbon liquids dissolved CO_2 and produced water dissolved CO_2
- EPA-HQ-OAR-2009-0923-1151-94: for a response to the commenter's cost estimate for reciprocating compressor rod packing venting
- EPA-HQ-OAR-2009-0923-1151-95: for a response to the commenter's cost estimate for pneumatic pumps
- EPA-HQ-OAR-2009-0923-1151-96: for response to the commenter's cost estimate for well venting for liquids
- EPA-HQ-OAR-2009-0923-1151-97: for response to the commenter's cost estimate for unconventional well completions and workovers
- EPA-HQ-OAR-2009-0923-1151-98: for response to the commenter's cost estimate for conventional well completions and workovers

- EPA-HQ-OAR-2009-0923-1151-99: for response to the commenter’s cost estimate for associated gas venting and flaring
- EPA-HQ-OAR-2009-0923-1151-100: for response to the commenter’s cost estimate for well testing flaring
- EPA-HQ-OAR-2009-0923-1151-101: for response to the comment about centrifugal compressor wet seal degassing vents
- EPA-HQ-OAR-2009-0923-1151-102: for response to the comment about EOR injection pump blowdown
- EPA-HQ-OAR-2009-0923-1151-103: for response to the comment about acid gas removal vent
- EPA-HQ-OAR-2009-0923-1151-104: for response to the commenter’s cost estimate for non-portable combustion units
- EPA-HQ-OAR-2009-0923-1151-105: for response to the commenter’s cost estimate for portable combustion units
- EPA-HQ-OAR-2009-0923-1151-106: for response to the commenter’s cost estimate for data management
- EPA-HQ-OAR-2009-0923-1151-129: for response to commenter’s cost estimate for produced water emissions
- EPA-HQ-OAR-2009-0923-1151-5: for details regarding EPA’s changes to address other commenters’ burden concerns.

Comment Number: EPA-HQ-OAR-2009-0923-1151-5
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Estimated Burden on Oil and Gas Production

The expansion of the MRR to include the entire natural gas supply chain, from dispersed wells and small facilities to distribution meter stations and city gates; tremendously expands the scope of the rule in terms of number of sites, source types, and monitoring/calculation methodologies. Given the size and complexity of the U.S. oil and gas production, gathering, processing, transmission, storage, and distribution sector; with over 823,000 producing wells, tens of thousands of ancillary facilities, thousands of miles of collection, transmission, and distribution pipeline systems, millions of individual pieces of equipment and components, and complex operating and ownership arrangements; it is imperative that a simple and innovative system be defined that balances the data collection and reporting burden against the amount of GHG emissions quantified.

API believes that EPA has significantly understated the cost and burden of the rule in their Economic Impact Analysis for the newly included Onshore Petroleum and Gas Production (OPGP) category. API’s projected burden and costs for the Onshore Petroleum and Natural Gas Production sector under the proposed rule exceed $1.8 billion, significantly larger than EPA’s projection of $27.7 MM. The cost per metric ton of CO2 equivalent emissions from API’s analysis is $8.17 compared to EPA’s estimated $0.18 per metric ton as stated in Table W-5 of the preamble. Details on how we reach this conclusion are provided in a separate cost analysis described in Section VI.

As illustrated in API's cost analysis, the burden of the rule is significantly higher than EPA has projected. Our estimates also show that in total over 2,200 man-years (based on 2,000 hours per year) are required by the oil and gas production sector in the first year just to meet the compliance requirements. As a result, we firmly believe that EPA's timing goals are unachievable given the vast number of sites and sources subject to this reporting rule that have not previously had regulatory reporting or inventory requirements, coupled with the extraordinary amount of work that must be done to implement the rule. To illustrate the impossibility of immediate implementation: if the average well site takes 2 hours to drive to and inventory components, it would take 667 man years (based on 2,000 hours per year) just to inventory the fugitive components and equipment on the 667,000 wells covered under the rule.

Absent withholding the Onshore Petroleum and Natural Gas Production portion of the rule, API recommends simplifying several portions of the rule, and a phased rule implementation approach in place of the current unrealistic deadlines.

To further streamline the burden imposed by Subpart W, EPA must provide a simplified screening mechanism for onshore oil and natural gas operations to determine if they are required to report. Without a threshold screening mechanism for any of the sector categories covered by Subpart W, all oil and natural gas operations have to compile a GHG inventory to determine if they exceed the threshold. EPA neglected to include the cost associated with this activity. In the first year, 100% of the source categories will need to be estimated using the proposed methods to determine the rule applicability.

API Requests:

To address this widely disparate projection of burden and costs, API requests the following:
- EPA should delay inclusion of the Onshore Petroleum and Natural Gas Production sector in the final rule pending a re-evaluation of the Economic Impact Analysis and rationalization of the rule requirements, rule approaches, burden, and costs versus the amount of emissions covered.
- To address the unprecedented amount of work and resources necessary to implement the rule as proposed, API requests the use of BAMM for source types requiring metered flow rates or monitored parameters for the initial year. BAMM is particularly important for a sector like oil and gas. Unlike a chemical plant or a refinery, oil and gas operations are spread out over a basin and are often not staffed at all times. Often there is little existing infrastructure at these disparate locations. Therefore, the use of appropriate meters and the counting of pieces of equipments will be more difficult for these spread out oil and gas sources. In addition, given that many of the sources are relatively minor individually and can be grouped together for estimation purposes, API has proposed several simplifications that do not compromise data quality. Even with event the Sub-basin entity simplifications that API has proposed, a phased implementation of the rule over a period of several years will be necessary to fully understand the requirement of the rule, inventory all sources subject to the rule, and develop data collection systems, etc. to comply with the rule.
- When re-structuring and finalizing the rule, EPA should take all opportunities to simplify the requirements and reduce burden. The rule should allow for simplified methods or outright

exemptions for devices and operations that are below a size or threshold level. Such units may include, but are not limited to, ‘no-bleed’ pneumatic controllers; storage tanks and gas dehydrators with low throughputs; small compressors, small combustion units and similar sources.

- EPA must provide a simple screening approach to determine applicability. For example, a Basin entity with 50 wells or less, at EPA’s estimated emissions of 370 tonnes CO2e per well, could be exempted from reporting.

Response:

Burden Comments: Monitoring Requirements and Scope of the Rule

EPA has carefully considered the complexity of the onshore production operational structure. As discussed in today’s final rule, EPA has decided to require reporters to monitor and report emissions from specific sources using monitoring methods tailored to minimize the reporting burden while maintaining the collection of reasonable-quality emissions data. For example, EPA has revised today’s final rule to require operators to count their major equipment instead of each individual components. Other changes include allowing the use of existing available produced gas composition data reducing the need to sample, setting equipment thresholds that require only a subset of equipment to be monitored more rigorously, and allowing the use of engineering estimation to determine equipment throughputs. See Section II.E of the preamble for all the major changes to the rule.

Regarding the comments about balancing the compliance burden against the data collected, see EPA’s response to EPA-HQ-OAR-2009-0923-1014-5, which discusses the analyses EPA conducted to consider these tradeoffs.

Compliance Cost Estimates and Underlying Labor Assumptions

EPA has also reviewed the commenter’s statements about the costs and weighed that input against its Economic Impact Analysis. EPA has concluded that while some adjustments were necessary (e.g. accounting for threshold determinations made by entities that do not meet the emissions threshold), the Agency’s methodology and assumptions were sound and relied on best available data to estimate the costs. Please see Sections 4 and 5 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for the changes to EPA’s cost estimate since the April 2010 proposal. EPA disagrees with the commenter’s cost estimates. EPA has analyzed the commenter’s cost estimates and determined that they are too high. A detailed analysis is available in EPA’s responses to comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment.

In addition, EPA disagrees with the commenter’s estimate of the number of man-hours required to report under the rule. Specifically, EPA disagrees with the commenter’s assumption that reporters would have no reason other than data collection for Subpart W to visit each of the wells. Please refer to EPA-HQ-OAR-2009-0923-1060-1 for further discussion.

Reporting Determination: Screening Tools and Cost Estimates

Regarding the costs for facilities to make a reporting determination, EPA agrees that the Economic Impact Analysis would better reflect the rule’s total economic burden by including all reporting determination costs. The Agency also agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the Preamble to today's final rule.

Recommendations for BAMM and Timing of Rule Implementation

Regarding the commenter's recommendation to delay implementation of the rule, see Section II.F of the preamble a complete response and discussion about conditions under which reporters may use BAMM. Regarding the phased-in implementation, EPA has modified the emissions monitoring requirements such that reporters can gather sufficient data in the first reporting year itself. Hence, EPA does not see the need to conduct a phased-in implementation. For any exceptional circumstances under which data cannot be gathered in the first year, the reporters have the option to request BAMM.

Comment Number: EPA-HQ-OAR-2009-0923-1151-89
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:

API believes that EPA has significantly understated the cost and burden of the rule in their Economic Impact Analysis – particularly for the newly included Onshore Petroleum and Gas Production (OPGP) category. Our analysis, which is not inclusive of all sources and costs, applies conservative (i.e., low) values for many of the estimates. Even with these conservative assumptions, our analysis suggests that EPA's projection of first year costs of $27.7 MM (preamble Table W-5) for this category is too low by more than an order of magnitude. Details of how we reached this conclusion follow:

- Although EPA notes that only 4% of the potential OPGP facilities (defined at the Basin level) will be covered under the rule (preamble Table W-2) at the proposed 25,000 metric ton threshold, EPA also determined that some 81% of the emissions from this category would be covered. It is logical to assume that to achieve 81% emissions coverage, close to 81% of the sites and equipment comprising the "facility" as defined in the rule would be covered by the rule. Assuming 81% of equipment and activities in the OPGP sector are included in the rule and with some 823,000 wells in the Energy Information Administration's (EIA) 2008 report, this implies rule coverage of about 667,000 of these well sites and the requirement for inventory and monitoring activities at each of them.

- Since the rule fails to provide a simple method of determining applicability, emission estimation is required at each individual well site and associated surface facility in this category just to determine if the reporting threshold is exceeded.
- Based on an analysis of wells per operator in each basin, the 667,000 count is likely low. (API can provide EPA with additional information on this analysis.) Applying emissions per well estimates of 5,000 (EPA's high range estimate), 700 (EPA's mid-range estimate), and 370 (EPA's low estimate) metric tons of CO_2e per well yields coverage of 846,142 wells, 737,985 wells, and 668,898 wells respectively.
- At each of these sites, owners/operators will have to undertake a detailed inventory of equipment and fugitive components on the site. As structured, the rule would require visiting

each well site to determine at least the following:
* Section 98.232(c)(1) and Section 98.233(a): High Bleed Pneumatic controller inventory with model number
* Section 98.232(c)(2) and Section 98.233(b): Low Bleed Pneumatic controller inventory
* Section 98.232(c)(3) and Section 98.233(c): Pneumatic Pump inventory by model number
* Sections 98.232(c)(10), (18), and (20) and Section Section 98.233(j), (x)n and (y): Tanks in both water and hydrocarbon liquid service
* Section 98.232(c)(11) and Section 98.233(p): Reciprocating Compressors by model number and horsepower
* Section 98.232(c)(21) and Section 98.233(r): Fugitive Component Inventory
* Subpart C: Combustion Unit Inventory

- Assuming that driving to each well site, inventorying the equipment and fugitive components and logging them for future entry into a database takes an average of 2 hours and that the average charge for a person and vehicle to conduct this inventory is $100/hr, the inventory of well sites alone would suggest a cost of about $133.4 MM for the initial inventory of well sites (667,000) which is 4.82 times EPA's total cost estimate for the OPGP sector.

- This same type of inventory activity would have to be conducted at other sites (i.e., non-well) within the OPGP category. Assuming one such site for every 100 wells with 3 hours per site (due to the larger nature of associated sites) and the same cost per hour, this would add an additional $2.0 MM in cost.

- In addition to the physical site inventory, the well bore configuration (depth, tubing size, casing size, packer arrangement, etc.) would have to be verified for each individual well to enable estimation of "blow-down" emissions for both the well venting for deliquification source type. It is assumed that this can be accomplished by a file review (electronic or hard copy) and will not require any physical inventory. Assuming 0.5 hours per well and fully loaded cost of $100 per hour for an engineering technician to review and verify the well-bore configuration adds an additional $33.3 MM in cost.

Response: Regarding the comment that EPA underestimated the costs, see EPA's response to EPA-HQ-OAR-2009-0923-1151-5 for a summary of EPA's assessment of the commenter's estimates and the Agency's estimates.

Percentage of Wells Reporting to Subpart W

In addition, EPA disagrees with the commenter's assumption about the number of wells subject to reporting under the rule, specifically, that 81 percent of the wells account for 81 percent of the emissions. This assumption, which resulted in much more labor and complex monitoring than required under the proposal, is incorrect. The magnitude of emissions from wells will vary because wells produce different volumes of natural gas and petroleum. Therefore, monitoring 81 percent of the wells does not necessarily account for 81 percent of emissions.
Instead of assuming that percentage of the rule's national emissions coverage (81) equals the percentage of national wells covered (81), EPA used data on actual production volumes to estimate the emissions per well. Specifically, EPA conducted the threshold analysis using actual data available through the commercial database from HPDI LLC, which collects these data

primarily from individual petroleum and natural gas producing States that require petroleum and natural gas producing companies to report field data. The HPDI database includes operator well count. In most cases, HPDI provides data for each well on the production of petroleum and natural gas by operator and basin; some data are listed by property, which is a collection of wells. EPA developed a reasonable estimate of the emissions per well by apportioning the national emissions from each emissions source type to each of the wells based on the contribution of petroleum and natural gas production from each well to the national total. This analysis suggests that approximately 60 percent of the wells are covered by the reporters, not 80 percent.

Furthermore, 60 percent is a conservative estimate for the number of potential site visits because multiple wells are typically connected to one set of equipment located at one of the wells. For example, the U.S. National GHG Inventory estimates that there are 2 to 3 wells connected to one separator. Hence, reporters will not need to visit all of their wells covered by the rule for detailed data gathering; EPA estimates that approximately 30 percent of the well pads in the U.S. will have equipment that may be visited for detailed data gathering.
In sum, the commenter's assumption about the number of wells covered produced a higher estimate of the number of wells covered, which in turn resulted in significantly higher estimates of compliance costs.

Cost to Visit Well Sites
In addition, EPA disagrees with the commenter's estimates of the costs to visit well sites and non-well sites to collect data for compliance with Subpart W. EPA has accounted for costs to gather rule-related data at the well sites assuming that reporters will accommodate data gathering during their routine business-as-usual site visits. See response EPA-HQ-OAR-2009-0923-1060-1 for further details.

EPA also disagrees with the commenter's estimates for well blow-down calculations, in particular the assumption that reporters would need to review and verify well-bore configurations. Reporters will need four parameters to do well blow-down calculations: well depth; well tubing diameter; well casing diameter; and well shut-in pressure. Oil and gas operators already submit most or all this information to individual state oil and gas commissions on an annual basis. In addition, this is basic data on wells that operators maintain internally. Therefore, EPA determined that reporters will not need to spend additional time verifying data about well-bore configurations that will have been recently verified for state or internal purposes. Accordingly, EPA deems the commenter's cost estimate as unnecessarily high.

Determination Cost and Screening Tools.
EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-90
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.232(c)(14) and Section 98.233(e): As proposed, the rule requires an inventory of each covered dehydrator unit for a variety of physical and operational parameters along with sampling of the inlet feed gas for composition and water content and the outlet gas for water content. Assuming 81% coverage of the 41,861 dehydrators in EPA's 2008 Inventory of Greenhouse Gas Emissions and Sinks for the Natural Gas Production Stage yields 33,907 dehydrators covered under the rule. An inventory of each of these is assumed to occur while inventorying well-sites and assumed to add 0.5 hours of contractor time at $100/hr yielding $1.7 MM in costs. Additionally, sampling and analysis of the dehydrator inlet and outlet gas for water content and the inlet gas for composition is projected to cost $25 for each water content analysis and $475 for each gas sample and extended compositional analysis. An additional 1.5 hours is projected for collecting the samples, set-up and modeling of each dehydrator at a rate of $100/hr. Applying the combined analytical costs of $525 per dehydrator to the 33,907 covered dehydrators yields an additional $17.8 MM in costs. Combined with the labor costs, this yields a total of $24.6 MM for dehydrator inventory.

Response: EPA disagrees with the commenter's cost estimate for dehydrator units, in particular the number of dehydrators subject to reporting. First, EPA disagrees with the assumption that 81 percent of the dehydrators listed in the 2008 Inventory of Greenhouse Gas Emissions and Sinks for the Natural Gas Production Stage; see the response to EPA-HQ-OAR-2009-0923-1151-89 for discussion about why it is inaccurate to assume 81 percent of sources are subject to monitoring. Instead, EPA obtained its estimate that 24,405 dehydrators will be subject to reporting under the rule from its threshold analysis, discussed in EPA-HQ-OAR-2009-0923-1151-89 and the T Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923).

Second, EPA disagrees with the commenter's assumption that 0.5 hours are needed to collect relevant information or that it should take 1.5 hours to run a software simulation run. Field operators know their equipment well enough to provide the necessary inputs without much deliberation. Furthermore, EPA has conducted GlyCalc® runs and has determined that it takes less than 10 minutes to run a simulation and copy the results into a data collection sheet. Moreover, 10 minutes is a conservative estimate because it does not account for simulation software configured to conduct multiple runs in tandem, which would not limit the user to running one dehydrator simulation at a time. The simulation software can be easily configured for multiple runs and would reduce the run time by up to 90 percent. Also, EPA assumed a junior engineer at $71.03 per hour would be performing this work. Please see Section 4 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for how EPA developed this labor category and labor rates. EPA cannot respond to the commenter's assumed labor rate ($100 per hour) because they did not provide any other information.

Third, EPA never intended for reporters to take samples to determine inputs to the simulation model. Therefore, EPA has clarified in today's final rule that reporters can use the default values available in simulation software. Please see preamble Section II.F for more details on using default software simulator composition values. Also, EPA has revised the requirements by setting a dehydrator equipment threshold, eliminating need to simulate emission from the majority of the dehydrators. Hence, the dehydrator costs do not apply. Please see Section II.F of the preamble for further details on the equipment threshold.

Comment Number: EPA-HQ-OAR-2009-0923-1151-92
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(18) and Section 98.233(x): Closely related to tanks in hydrocarbon service is the Hydrocarbon Liquids Dissolved CO2 category. Although EPA's Technical Support Document discusses this category only in relation to CO2 EOR operations, the rule requires quarterly sampling and analysis of the hydrocarbon liquid in all tanks in the production category after they have equilibrated to ambient conditions. (Please note that the efficacy of this category is discussed in another API comment specific to the source category.) Assuming that there are 0.25 tanks per oil well and between 0.2 and 0.92 tanks per gas well, yields a range of tanks nationally from 183,000 to 514,000 in the production category. Applying the assumption that 81% of the tanks are covered by the rule results in an estimated number of tank ranging from 148,000 to 416,000. Based on this projected number, quarterly sampling, and a cost of $475 per sample gathering and analysis, this yields a cost ranging from $271 MM to $791 MM for this emission source.

Response: EPA did not intend to require quarterly sampling and analysis of the hydrocarbon liquid in all tanks in the production category. Therefore, EPA has clarified in today's final rule that only hydrocarbon liquids at EOR sites have to be sampled on an annual basis. See response to comment EPA-HQ-OAR-2009-0923-1011-21 for further details. EPA has estimated that about 21 EOR operations will have to report to the rule. Hence the number of samples will be equivalent to the number of tank batteries at these EOR operations. Therefore, today's final rule requires much fewer samples for tanks in hydrocarbon service than assumed by the commenter. Also, today's final rule does not require reporting of any produced water emissions. See response to comment EPA-HQ-OAR-2009-0923-1151-129 for further details..

Comment Number: EPA-HQ-OAR-2009-0923-1151-96
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(4) and Section 98.233(f): For well venting for liquids unloading the rule has two options which will be detailed separately:
* Method #1 requires measurement of the vent rate during liquids unloading from each reservoir/tubing size combination in each field. Examining EIA's 2008 field list, API estimates 15,716 (81%) of the 19,402 gas fields are included in the rule. Based on an assumption of one producing reservoir per field, 3 discrete tubing sizes per field, and 2 operators per field, some 94,000 discrete measurements would have to occur. At a projected cost of $1,000 per measurement, for temporary piping modifications, installation of a temporary recording flow-meter, conducting the measurements, and returning the piping to its original configuration, the cost of measurement would be $94 MM. Assuming 2.5 hours per field/tubing size/operator

combination (94,000) and $100 per hour to track venting by combination and perform the calculations for emissions estimation an additional cost of $23.5 MM is projected. The total projected cost for this category is $117.9 MM.

* Method #2 requires calculation of the "blow-down" volume from de-pressuring each individual well-bore along with tracking, at an individual well level, the number and time of each individual venting event. With some 373,000 gas wells subject to the rule (81%) and assuming EPA's estimate that 41.3% of these wells vent for liquids unloading, this source will require about 154,000 individual well-bore de-pressuring volume calculations. Using an average of 31 discrete vent instances per venting well per year (EPA's estimate) would require tracking of the number and time of some 4.7 million discrete venting instances per year. To arrive at an emission estimate would require subsequently calculating emissions for each of the 154,000 wells and then summing these emissions, on a Basin entity level, for annual emissions. Assuming 0.5 hours total per well to calculate the well-bore de-pressuring volume for each affected well; 0.1 hours per event to track, QA/QC, and log the time; and 0.2 hours per well to calculate and QA/QC the vent volumes to arrive at an emissions estimate, at $100 per hour this yields an estimated 293 man years of time (@2,000 hours/yr) and $58.5 MM cost for this method.

Response: EPA disagrees with the commenter's assumptions and resulting cost estimates. EPA proposed two options for reporters to monitor well unloading, described as Method 1 and Method 2 by the commenter above. Method 2 is less costly than Method 1. Under the proposal, reporters could use the costlier option but were not required to do so; same is true of today's final rule. Therefore, EPA's analysis assumed reporters would use the lower cost option (Method 2) in its analysis and did not evaluate the higher cost option.

EPA has analyzed the commenter's estimate of the costs for Method 2 and has determined that it is too high because it is based on four incorrect assumptions. First, the assumption that 81 percent of wells are subject to reporting leads to an overestimate of the number of wells requiring blowdowns (154,000). Please see EPA's response to EPA-HQ-OAR-2009-0923-1151-89 for why 81 percent of U.S. wells are reporting is too high. Instead, EPA has estimated that 137,662 wells requiring blowdowns will need to be reported, based on its assumption that 41.3 percent of the reporting wells will need a blowdown. EPA's 41.3 percent assumption was derived from well blowdown data found in GRI & EPA (June 1996) *Methane Emissions from the Natural Gas Industry*. Volume 6. Second, EPA does not agree that it will take 0.5 hours to calculate emissions per well. The calculation method provided by EPA can be set up in a spreadsheet or database such that once the input data is available, the spreadsheet or database can replicate the calculation for each well within a few minutes for an entire basin.

Third, EPA disagrees that an operator would need 0.1 hours per well to log the time for well opening and shutting to atmosphere in a data sheet; most likely less than a minute per well would suffice because the operator only needs to note the time the well was opened to the atmosphere, the time the well was closed, and the duration of time that the well was open to the atmosphere. Also, the 0.2 hours for calculating and QA/QC per well is redundant with the assumed increment of 0.5 hours per well to calculate the well-bore de-pressuring volume. Finally, once a spreadsheet or database is set up correctly, the electronic system replicates all of the calculations and requires minimal QA/QC. Therefore, the time assumed to set up the spreadsheet or database does not apply to each calculation on a well-by-well level.

Considering all the points above, EPA has determined that its assumptions and methodology are valid and result in a realistic cost estimate for reporting well blowdowns at about $733,000.

Comment Number: EPA-HQ-OAR-2009-0923-1151-97
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(6) and Section 98.233(g): Unconventional Well Completions and Work-overs: The proposed rule details two different methodologies for estimating emissions from unconventional well clean-up, post fracture stimulation, on completion or work-over (which appears to be defined as re-stimulation by repeat hydraulic fracturing in the rule) emissions which are discussed separately. For both methods, the following assumptions were applied to quantify the number of measurements:
* Completion: With an average of 28,800/yr wells drilled in the 2007 – 2009 period it is obvious that drilling and completion did not occur in every field covered by the rule. Assuming 25% of the estimated 15,716 impacted gas fields had active drilling and completion, that 90% of these were fracture stimulated and thus unconventional, and that there were 2 covered operators per field, yields an estimated range of 7,072 measurements that would be required.
* Work-over: Assuming that 50% of the existing covered gas wells are unconventional, that 10% of these are re-stimulated annually (EPA's estimate), that between 1% and 25% of the fields have active re-stimulation each year, and that there are two covered operators per field, yields an estimated 157 to 3,929 work-over measurements per year.
* Method #1 requires the measurement of flow rate during clean-up for one well completion and one well work-over in each field. From this a flow rate per minute is derived and applied to the minutes of flow-back from each completion and work-over in a field. Applying an estimated cost of $1,000 per measurement to between 7,200 and 11,000 estimated measurements yields cost ranging from $7.2 MM and $11 MM for measurement. Assuming that tracking the vent time per completion and work-over and performing the calculations requires 1 hour of time at $100 per hour yields a cost of $3.9 MM which brings the total range to $11 MM to $15 MM for this category/methodology.
* Method #2 requires monitoring across the completion choke and calculation of flow rate during clean-up for one well completion and one well work-over in each field. From this a flow rate per minute is derived and applied to the minutes of flow-back from each completion and work-over in a field.
Applying an estimated cost of $500 per differential pressure measurement and subsequent calculation to the estimated 7,200 to 11,000 measurements yields a cost range of $3.6 MM to $5.5 MM for differential pressure tracking and flow modeling. Assuming that tracking the vent time per completion and work-over and performing the calculations requires 1 hour of time at $100 per hour yields a cost of $3.9 MM which brings the total cost range from $7.6 MM to $9.5 MM for this category/methodology.
Response: EPA disagrees with the commenter on the estimate of well completion and well workover activity data used for burden analysis, as explained below. EPA determined that

installing a flow meter on at least one completion per field, cited as Method #1 in the comment above, is the lower cost option. EPA's analysis assumed reporters would use the lower cost option (Method #1) and therefore did not evaluate the higher cost option, Method #2.

Well Completions

Instead of assuming 25 percent of the reporting fields have active completions and that 90 percent of these completions are hydraulically fractured, EPA used actual year 2006 data from HPDI, LLC to determine which fields had any form of completions. The data showed only 1,177 unconventional field and operator combinations with any form of well completions in the year 2006. Since the rule requires only one sample of well completion emissions per field, these 1,177 unconventional field combinations equal 1,177 samples. Of these samples, only 435 are covered by reporting entities, far fewer than the 7,072 measurements estimated by the commenter.

Workovers

The commenter incorrectly assumed that 50 percent of the gas wells covered by the rule are unconventional. EPA estimated from the HPDI database that the actual number is 88,588 gas wells or 20 percent. EPA cannot comment on the commenter's assumption of 50 percent because they did not substantiate it.

Based on the HPDI database, EPA estimates that there were a total of 1,535 operator and unconventional gas well fields combinations in year 2006. Assuming each of these combinations will have at least one sample workover measurement, EPA estimated that a total of 1,535 samples will be collected for year 2006, less than the 3,929 estimated by the commenter.

Cost estimates

EPA agrees with the commenter's cost estimate per gas well sample, but disagrees with the total estimates because they based them on inaccurate activity data. Also, EPA disagrees with the commenter's estimated labor rates; please see EPA's response to EPA-HQ-OAR-2009-0923-1151-90 for a response to this issue.

Comment Number: EPA-HQ-OAR-2009-0923-1151-98
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:

Section 98.232(c)(5) and Section 98.233(h): Conventional Well Completion and Work-over: For conventional well completion and work-over, the rule specifies tracking of venting time per individual well completion or work-over and then applying the wells production rate to calculate the emission volume. Based on nearly 373,000 gas wells impacted by the reporting rule, and assuming 50% are conventional and 10% are re-stimulated annually, results in an estimated 18,600 work-over procedures. An estimated 2,300 completions per year was based on 81% of the number of gas wells drilled and an assumed 10% are conventional completions. Combined with these values, an assumption of 1 hour of time at $100 per hour to track the vent time per completion and work-over, and 1 hour of time at $100 per hour to perform the calculations, the projected cost is $2.1 MM.

Response: EPA disagrees with the commenter's activity data assumptions and costs estimates. EPA estimates of 1,663 fields with conventional completions and 17,931 conventional workovers are based on actual data from HPDI database rather than an assumption. Also, EPA does not see the need for 1 hour to track time taken for completion; this is a matter of logging when the well completion started and when it ended, which would require, at most, a few minutes. Please see Table 4-13 in the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for the exact time estimated for a junior engineer and senior operator to determine the emissions from conventional well completions and conventional well workovers. Finally, EPA does not agree that it will take 1 hour to simply multiply two terms (completion/ workover time and well flow rate) for each well. It does not take that amount of effort to do this calculation manually, and even less time when using a spreadsheet or database. Hence, the commenter's cost estimates significantly overstate the burden.

Comment Number: EPA-HQ-OAR-2009-0923-1151-99
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(13) and Section 98.233(m): Associated Gas Venting and Flaring: EIA tracks the volume of natural gas vented and flared in the US. In 2006, EIA reported only 0.56% of gross natural gas production in the US was vented or flared. As a result, the application of the emission estimates for flares is not expected to impact many sources. For associated gas flaring, API assumed that 0.5% of associated gas wells impacted by the rule flare gas, this results in 972 wells that would report flared emissions. Assuming 1 hour to determine the GOR for each well at $100 per hour, results in a projected cost of $97K.

Response: In the analysis for today's final rule, EPA assumed that all of the Williston basin is venting and/or flaring their associated gas, which involves approximately 4,421 wells. EPA based this estimate on experience from the Natural Gas STAR program. The dataset cited by the commenter is less preferable in this case because it includes emissions from sources other than those covered by this requirement, such as well completions and workovers.

Furthermore, today's final rule allows reporters to use existing GOR data, which will minimize the costs to report emissions from this source. See Sections II.C and II.F of the preamble for more information about EPA's decision to allow use of existing GOR data instead of requiring sampling.

Comment Number: EPA-HQ-OAR-2009-0923-1167-10
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Subpart W GHG reporting requirements include 21 emission sources for onshore petroleum and natural gas production. In addition, affected facilities (reporting areas) are required to report

emissions from Subpart C combustion sources and also have requirements for characterizing field gas composition. These extensive reporting requirements - which require equipment calibration, equipment surveys, measurements, process samples, and recordkeeping - place an excessive and disproportionate burden on the onshore production sector. The locations of onshore exploration and production (E&P) sources (i.e. large geographic distribution), and lack of onsite power to automate data collection (e.g. manual data logs would be required) significantly add to the resources needed to implement the data collection and reporting requirements. The result is an excessive cost burden that has been significantly underestimated by EPA.

Response: EPA does not agree with the comment. For a response to the comment about the estimated costs for onshore production, please see EPA's response to EPA-HQ-OAR-2009-0923-1151-107. Please see Section II.F in the preamble for further details regarding changes to field gas composition requirements. In addition, see EPA's response to EPA-HQ-OAR-2009-0923-1151-5 for discussion about travel to exploration and production sources; see EPA's response to EPA-HQ-OAR-2009-0923-1151-104 and EPA-HQ-OAR-2009-0923-1151-105 for discussion about the costs to report incremental combustion emissions. Finally, this rule requires a one-time monitoring of emissions, not continuous monitoring. Therefore, EPA disagrees with the commenter's assumption that reporters will need automated data collection and onsite power for this purpose.

Comment Number: EPA-HQ-OAR-2009-0923-1167-11
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

<u>Comment Excerpt Text:</u>
Mandatory Reporting Rule (MRR) compliance for onshore petroleum and natural gas production will require extensive effort including, but not limited to, direct emission and process measurements (e.g. flow meters), thousands of quarterly and annual process samples (e.g. storage tank liquids, separator liquids, gas samples), thousands of equipment surveys, calculations and data management for thousands of emission sources, and project management, record-keeping and reporting. Table 1 presents estimated Noble Energy costs for MRR compliance including first year (Year 1) and subsequent year (Year 2+) estimated $/tonne CO_2e costs for each emission source and the entire Noble inventory. These cost estimates are based on the emission measurement and estimation methods prescribed in Subpart W and Subpart C, and GHG emission estimates from the Noble Energy 2008 inventory. Details regarding the data, methods, and assumptions used for these cost estimates are provided in Attachment A. These estimates provide guidance regarding emission sources where alternative, simpler emission estimation requirements and methods are needed for reasonable compliance costs.

Table 1. Estimated Noble Energy Cost to Comply with MRR Subpart W and Subpart C for Onshore Petroleum and Natural Gas Production Emission Sources.

Emission Source	% of US Inv.[A]	NE Costs ($/tonne CO2e)[B]		Notes
		Year 1	Year 2+	
Well Venting for Liquids Unloading [98.233(f)]	24%	$11.00	$9.00	C
Associated Gas Venting and Flaring [§98.233(m)]	12%	$2.00	$1.70	
Gas Well Venting During Unconventional Well Completions and Workovers [98.233(g)]	12%	$1.20	$0.51	
Gas-Fired Reciprocating IC Engines (Combustion)	11%	$2.90	$2.50	
External Combustion: Heaters, boilers	8.4%	$3.70	$2.10	D
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	6.9%	$1.30	$0.19	
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	6.6%	ND	ND	
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	3.9%	$2.60	$0.37	
Dehydrator (glycol) Vent stacks [98.233(e)]	3.1%	$12.00	$10.00	
Components [§98.233(r)]	3.0%	$17.00	$2.401	
Produced Water Dissolved CO2 [§98.233(y)]	2.7%	$21.00	$18.00	E
Production Storage Tanks [98.233(j)]	2.2%	$18.00	$16.00	
Gathering Pipeline Fugitives [§98.233(r)]	1.6%	$46.00	$6.60	
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	0.7%	$43.00	$24.00	
Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	0.7%	-	-	F
Natural Gas driven pneumatic pumps [98.233(c)]	0.6%	$1.50	$0.54	
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	0.1%	ND	ND	
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	0.1%	$49.00	$7.40	
Gas Well Venting During Conventional Well Completions and Workovers [98.233(h)]	0.1%	ND	ND	
Dehydrator (Desiccant) Vent stacks [98.233(e)]	0.1%	ND	ND	
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	0.0%	$38,000.00	$33,000.00	
EOR Injection Pump Blowdown [§98.233(w)]	0.0%	ND	ND	G
Well Testing Venting and Flaring [§98.233(l)]	0.0%	NA	NA	H
Flare Stacks [§98.233(n)]	0.0%	NA	NA	I
Gas Composition [§98.233(u)]		NA	NA	J
TOTAL	**100.0%**	**$8.50**	**$5.90**	

ND – data not available

NA – not applicable

A. Estimated percent of US onshore production GHG inventory from Table 2.
B. 2010 dollars. Data management, calculations, record-keeping, and reporting costs allocated to emission sources proportional to source emission estimation cost.
C. Well Unloading emissions and compliance costs are expected to reduce as more plunger lift operations are automated and optimized.
D. Based on simple "company records" including burner rating and estimated operating hours. Assumed that totalizing flowmeters will *not* be installed on all external combustion equipment.

E. Emission estimate based on engineering judgment and assumptions and additional data needed to refine estimate.
F. Minimal compliance costs; emissions based on population emission factor and readily available production data.
G. Based on docket data, 500,000 pumps would be needed to account for about 0.1% of sector GHG emissions.
H. The majority of well tests are conducted while the wells are in operation and do not require flaring. Other well tests would be included in well completion and well workover estimates.
I. Flare emission estimates included in other emission source specific estimates.
J. Cost to collect and analyze gas samples included in Total but not included in costs for individual emission sources.

Attachment A – Documentation of Estimated MRR Compliance Costs for Noble Energy Onshore Petroleum and Natural Gas Production Operations

This attachment describes the data and methods that were used to estimate Mandatory Reporting Rule compliance costs for Noble Energy onshore petroleum and natural gas production sources affected by Subpart W and Subpart C. Compliance costs were estimated for most of the affected emission sources and for preparing the entire inventory. The GHG emissions data that are the basis for the majority of the estimates are from the Noble Energy 2008 GHG emission inventory. This inventory is primarily based on emission estimation methods from and consistent with the API Compendium. For some of the emission sources that are not included in the Noble inventory, emissions were estimated using Subpart W or Subpart C methods if applicable activity data were available. Emissions could not be estimated for some sources.

Table A.1 provides summary information for each affected emission source. As available, CO2e emission estimates from the Noble 2008 are presented with estimated compliance costs for the first year (i.e. Year 1) and subsequent years (i.e. Year 2+). Estimated compliance costs are presented as $/tonne CO2e for the emission source. These costs include physical sample collection and analysis and/or direct measurements, engineering calculations (e.g. E&P Tanks), equipment calibrations, personnel training, recordkeeping, emission source level and rolled up calculations, and reporting. Based on Noble's interpretation of the rule requirements, the last column details the data, methods, and assumptions (e.g. survey and/or measurement of different emission sources during a single site visit) used to estimate the costs. As would be expected at this stage of a rulemaking, there is considerable uncertainty in these cost estimates. In addition to the assumptions discussed in the Table A.1, other factors that could impact costs include a shortage of service providers and trained personnel, and excessive demand (i.e. industry wide, millions of emission sources would require survey, sampling, and/or measurement), and complications with field measurements and process sampling (e.g. pressurized separator water and oil samples).

Year 2+ costs for emission sources that require a survey (e.g. components, pneumatic devices), are assumed to be 15% of the Year 1 costs based on a Noble average annual operations acquisition and organic growth rate of 15%. Year 2+ costs for emission sources that require annual or quarterly sampling and/or direct measurement are generally assumed to be 90% of Year 1 costs to account for efficiency improvements.

Average sampling + analytical cost per sample are included as applicable. For process sample collection and analysis (e.g. field gas or separator liquids composition), industry budgetary costs typically range from $150 to $250 per sample. The costs presented in Table A.1 are generally consistent with or lower than these guidelines suggesting they could be a low-biased estimate of the true costs.

Table A-1. Data and Methodologies Used to Estimate Emission Estimation Costs for Onshore Production Sources Affected by MRR Subpart W.

Emission Source	% of US GHG Inv.	Noble GHG Inv. CO2e (tonne/yr)	Year 1 Costs ($/tonne CO2e)	Year 2+ Costs ($/tonne CO2e)	Notes
Well Venting for Liquids Unloading [98.233(f)]	24.3%	89,727	$10.67	$8.56	Must calculate average flowrate per minute for each unique tubing diameter and producing horizon/formation combination in each producing field (Method 1) and apply this flowrate to unloadings from similar wells. Method 2 requires, for each well venting, determine well shut in pressure and duration (in addition to well dimensions). This estimate is for Method 1 because pressure measurements for every event for Method 2 would be prohibitively expensive. For each unique tubing diameter and producing horizon/formation combination assume 4 hours to conduct measurement (set up meter & drive time). Assume 15 minutes to document duration (start and stop) of each event. Approximately 29,000 events per year - about 90% of costs from tracking duration of each event and only about 10% from measurements. It is anticipated that recently commenced project to install automated plunger systems will reduce number of events, emissions, and associated tracking and reporting costs.
Associated Gas Venting and Flaring [§98.233(m)]	12.2%	153,531	$1.64	$1.40	For Noble GHG Inventory includes both vented and flared associated gas. Costs based on collecting annual pressurized oil samples for GOR analysis from 1,319 oil wells that either vent or flare associated gas. 98.233(m)(1) states "Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared" Assume can collect 8 pressurized samples per day in these areas. Average cost per sample about $175 (may be biased slightly low). Oil production must be tracked.
Gas Well Venting During Unconventional Well Completions and Workovers [98.233(g)]	11.6%	268,852	$0.55	$0.40	For one well completion in each gas producing field and for one well workover in each gas producing field, measure gas flow rate by installing a meter or pressure drop across choke. Use this flow rate EF for all other wells in field. Track duration of all well completions and workovers. For Noble in 2008, about 33% of gas from well completions and workovers is vented and 67% flared. Costs based on measuring choke pressure drop (Calculation methodology 2) – assume 4 hours per event (set up P gauge and travel time) and about 50 producing fields.. Assume 15 minutes to document duration (start and stop) of each event and about 3,400 total events per year. Year 2+ costs based on every other year testing.
Gas-Fired Reciprocating IC Engines (Combustion)	11.3%	211,988	$1.62	$1.19	Engine fuel use calculated from engine load, BSFC, and operating hours. Engine load for compressor drivers determined from control panel parameters (compressor P, T) and compressor manufacturer software. Engine data collected quarterly (15 minutes per event) and 0.5 hours/yr to calculate engine load + 0.5 hours per engine Year 1 to record & document engine data and set up data logs (make, model, etc). 900 ICEs in inventory.
External Combustion: Heaters, boilers	8.4%	265,864	$3.72	$2.12	Fuel consumption estimate based on burner rating, and estimated annual operating hours (e.g. estimate of months operating and percent time firing). Heater/separator data collected quarterly (15 minutes per event) + 0.5 hours per engine Year 1 to record & document equipment data and set up data logs (make, model, burner, rating, etc) . 6050 units in inventory.
Natural Gas Pneumatic Bleed Devices (High or Continuous) [98.233(a)]	6.9%	256,723	$1.30	$0.19	Need to survey all wells and document high-bleed devices by make and model. First Year costs based on surveying 10,237 wells and 0.3 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.
Portable Combustion Sources (Drill Rigs) [§98.233(z)]	6.6%		-	-	This emission source was not included in Noble Energy GHG inventory, drilling companies have operational control.
Natural Gas Pneumatic Bleed Devices (Low) [98.233(b)]	3.9%	87,423	$2.59	$0.37	Need to survey all wells and document low-bleed devices by make and model. First Year costs based on surveying 10,237 wells and 0.2 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.
Dehydrator (glycol) Vent stacks [98.233(e)]	3.1%	6,796	$11.92	$10.39	Costs based on 60 glycol dehys in Noble Inventory. Need to collect and analyze natural gas samples & dehy parameters (2.5 hours per dehy) and run GLYCalc and document data (1.5 hours per dehy)
Components [§98.233(r)]	3.0%	99,081	$16.88	$2.41	Need to survey all wells and count components on all equipment. First Year costs based on surveying 10,237 wells and 1.5 hours per well including travel, data organization, etc. Assumed that survey of high-bleed pneumatics, low-bleed pneumatics, and components are done simultaneously. For subsequent years assume 15% new wells.

Produced Water Dissolved CO2 [§98.233(y)]	2.7%	103,529	$23.26	$19.90	Quarterly sampling and analysis required for post-separator water for CO_2. Dissolved CO2 not determined for Noble GHG inventory so estimate based on GOR for CO_2 in water estimated to be 12 scf/bbl based on average separator pressure of 85 psi and charts prepared by Kansas Geological Survey. Produced water volume of 131 MMbbls from Noble 2008 GHG inventory. Assume can collect 8 pressurized samples per day per technician (prep, travel, sampling, sample custody and shipping). 5,893 separators in inventory. These costs are shared with sampling required for HC tanks dissolved CO2 samples; and also only based on 3 of 4 quarterly samples because one sample already collected for storage tanks flash gas samples (for E&P Tanks) . Costs would be higher without these shared labor costs. Estimated sampling + analytical cost per sample ≈ $125 (lower than normal range).
Production Storage Tanks [98.233(j)]	2.2%	210,643	$18.18	$15.56	For Noble GHG Inventory, about 22% of gas is vented, 69% flared, and 9% recovered by a VRU. Costs based on collecting annual pressurized oil and water samples from 5,893 separators. Also need to collect a tank sample of sales oil for API gravity and Reid vapor pressure analysis. Average cost per sample about $200. If only collect oil or water sample then cost per sample would increase. Assume can collect all three (two pressurized) samples from 6 separators/tanks per day. Not sure what software used to estimate emissions from Produced water tanks.
Gathering Pipeline Fugitives [§98.233(r)]	1.6%	23,997	$23.23	$3.31	First Year costs based on surveying pipelines ("flowlines" and "intra-facility gathering lines" per 98.230(a)(2)) associated with 10,237 wells and 0.5 hours per well including travel, data organization, etc. Requires person familiar with Noble operations and pipelines. For subsequent years assume 15% of first year costs based on expansion (new wells), acquisitions, divestitures, and modifications. This estimate could change depending on how gathering pipelines are defined; i.e. are high pressure "flowlines" associated with gas wells considered gathering pipelines?
Reciprocating Compressor Rod Packing Vents (Blowdown Leak & Blowdown Vent (Unit Isolation Valve Leak) [§98.233(p)]	0.7%	8,425	$42.66	$24.43	Annual measurement requirements are vented gas flowrate from rod packing, unit isolation valves, and blowdown valve in three operating modes: Operating, Standby pressurized, and Not operating, pressurized. Assume can test average of 2.5 compressors per day in three modes (50% of tests three per day, 50% of tests two per day). Operator required to change compressor operating mode for testing. Purchase of six hi-flow samplers. Annual operating hours in each mode must be tracked/estimated. 145 compressors in inventory

Coal Bed Methane (CBM) Produced Water Emissions [§98.233(r)]	0.7%		-	-	This emission source was not included in Noble Energy GHG inventory. Cost to report these emissions expected to be very low because activity data are available from production reports and emissions based on population EF.
Natural Gas driven pneumatic pumps [98.233(c)]	0.6%	85,167	$1.45	$0.54	First Year costs based on surveying 1,514 devices and 0.5 hours to survey each device (get make and model, service, scf/gal data, set up data log) and 0.25 hours to collect liquid used data. For subsequent years assume 15% new devices (based on expansion (new wells), acquisitions, divestitures, and modifications)and must be surveyed by operators with same liquid use data collection requirements for all pumps
Centrifugal Compressor Wet Seal Oil Degassing Vent [§98.233(o)]	0.1%	0	-	-	No Centrifugal Compressors in Noble inventory
Acid Gas Removal (AGR) Vent stacks [98.233(d)]	0.1%	1,437	$48.66	$6.62	Measurement requirements are metered flow of pre- and post-AGR gas, and quarterly sampling and analysis of pre- and post-AGR gas for CO2. Year 1 costs include specify, purchase, and install six meters (3 AGRs) and quarterly samples. Year 2+ costs include recalibrate flow meters and quarterly samples. Estimated sampling + analytical cost per sample ≈ $175.
Gas Well Venting During Conventional Well Completions and Workovers [98.233(h)]	0.1%		-	-	For this analysis, assume all completions and workovers are unconventional.
Dehydrator (Desiccant) Vent stacks [98.233(e)]	0.1%	0	-	-	No desiccant dehydrators in Noble inventory
Hydrocarbon Liquids Dissolved CO2 [§98.233(x)]	0.0%	73	$41,203	$35,262	Quarterly sampling and analysis of post-flash HC storage tank liquids for CO2. Dissolved CO2 not determined for Noble GHG inventory so estimate based on average GOR of 150 scf/bbl, 2% of gas does not flash, and 3.9% of gas is CO2 (based on Watt flash gas analysis). 11.8 MMbbl condensate + oil from Noble 2008 inventory. Assume can collect 8 pressurized samples per day per technician (prep, travel, sampling, sample custody and shipping). 5,893 separators in inventory. These costs are shared with sampling required for water separator for dissolved CO2 samples; and also only based on 3 of 4 quarterly samples because one sample already collected for storage tanks flash gas samples (for E&P Tanks). Costs would be higher without these shared labor costs. Estimated sampling + analytical cost per sample ≈ $150 (low end of normal range).
Flare Stacks [§98.233(n)]	0.0%	15,727	-	-	Flared gas emissions calculated for individual sources (e.g. well completion) are included in the totals.
Well Testing Venting and Flaring [§98.233(l)]	0.0%		-	-	Emissions from this emission source are included in well completion estimates.
EOR Injection Pump Blowdown [§98.233(w)]	0.0%		-	-	This emission source is not included in Noble Energy operations and GHG inventory.
Total			**$8.47**	**$5.88**	A

A. Cost to collect and analyze gas samples included in Total but not included in costs for individual emission sources.

Response: EPA has reviewed the commenter's cost breakdown for each source and responded below. While EPA has responded to the information provided, the commenter did not provide all the necessary calculations for EPA to assess the cost per metric ton for each source.

<u>Well Venting for Liquids Unloading</u> – EPA does not agree with the comment. First, Method 2 is considerably simpler and cheaper for most operators than Method 1 because Method 2 is predominantly a desktop calculation. The data necessary to do this calculation—well tubing/casing diameters, shut-in pressure, and well depth—are well-known to the operators because most States require reporting of this data on an annual basis (see EPA-HQ-OAR-2009-0923-1151-96). The only new input required to do the Method 2 calculation is the time taken for blowdown. Specifically, when the blowdown is manual, the operator conducting the blowdown can keep a simple log and when the blowdown is based on a timer (e.g., in cases where there is a plunger lift), it is simply a matter of gathering the timer data. None of these tasks are burdensome. In sum, EPA disagrees with the commenter's assumptions and high cost estimate to monitor this source because the data are available and easily attainable.

Associated Gas Venting and Flaring – EPA has revised today's final rule to allow for use of existing GOR data, thereby avoiding the need for reporters to make a GOR determination each year. Most operators know their GOR, which will reduce the burden to monitor this source. See also EPA's response to EPA-HQ-OAR-2009-0923-1151-99 for additional discussion about this estimate.

Gas Well Venting during Unconventional Well Completions and Workovers – EPA generally agrees with the assumptions on time taken to monitor emissions. However, EPA does not agree with the commenter's methodology to calculate the cost. Reporters are required to only measure one well completion and workover event per field. Please see Section II.D of the preamble for further details. The commenter estimated the cost to measure all the well completions and workovers events, 3,500, during a reporting period for 50 fields and consequently over-estimated the cost. EPA's response to comment EPA-HQ-OAR-2009-0923-1151-97 provides additional discussion about EPA's assumptions and estimates for this emissions source.

Gas-Fired Reciprocating IC Engines and External Combustion (Heaters, boilers) – EPA has significantly simplified the monitoring requirements for today's final rule. The reporters can use Tier 1 from Subpart C or similar method from Subpart W using existing company records. This will significantly reduce burden to report combustion emissions. See EPA's response to EPA-HQ-OAR-2009-0923-1151-104 and EPA-HQ-OAR-2009-0923-1151-105 for discussion about the costs to report incremental combustion emissions.

Natural Gas Pneumatic Devices (low and high) and Pumps - EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble for further details.

Portable Combustion Sources (Drill Rigs) – EPA notes that emissions from drilling rigs have to be reported by the reporter, irrespective of operational control. See EPA's response to EPA-HQ-OAR-2009-0923-1151-104 and EPA-HQ-OAR-2009-0923-1151-105 for discussion about the costs to report incremental combustion emissions.

Dehydrator (glycol) vent stacks – Today's final rule does not require reporters to sample natural gas in order to do the dehydrator emissions calculation. Instead, reporters may use default values in the software program to estimate dehydrator emissions. See Section II.E of the preamble for further details. EPA disagrees the commenter's estimate of the time required to run GLYCalc. See response EPA-HQ-OAR-2009-0923-1151-90 for EPA's complete response.

Components – See response to EPA-HQ-OAR-2009-0923-1151-5 for discussion about changes EPA made to today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component. Also, EPA does not agree with the commenter's assumptions about travel costs related to the monitoring requirements. See response EPA-HQ-OAR-2009-0923-1151-5 for EPA's complete response.

Produced Water Dissolved CO_2 – EPA has removed this source from today's final rule. See EPA's responses to comments EPA-HQ-OAR-2009-0923-1151-129 and EPA-HQ-OAR-2009-0923-1151-93 for further details.

Production Storage Tanks – Today's final rule does not require sampling of low pressure separator oil for tank emissions calculation and instead permits reporters to use default values in software programs. See EPA's response to comment EPA-HQ-OAR-2009-0923-1151-90 for more information about EPA's estimate of the costs for this activity. EPA does not have sufficient details on the commenter analysis to respond in detail. For example, the commenter did not specify their assumptions for the hours needed to run a tank emissions simulator or collect the input data required.

Gathering Pipeline Fugitives - EPA has removed this source from today's final rule. See Section II.E of the preamble for further details.

Reciprocating Compressor Rod Packing Vents – In today's final rule, reporters can estimate emissions from compressors in onshore petroleum and natural gas production using emissions factor and activity count. This change from the proposal will significantly reduce burden to reporters from 30 minutes to read a portable vane anemometer to a few minutes to count the compressor and apply an emission factor. The commenter's assumptions about the cost for taking measurements are therefore no longer relevant.

Acid Gas Removal (AGR) Vent Stacks - Today's final rule allows reporters to use engineering estimation under certain conditions to determine flow rate to an AGR. See EPA's response to comment EPA-HQ-OAR-2009-0923-1024-26 for further details. This will significantly reduce burden because it does not require reporters to install new meters. Therefore, the commenter's cost estimate for AGR is no longer relevant for today's final rule.

Hydrocarbon Liquids Dissolved CO2 – In today's final rule, EPA has clarified that this requirement applies only to EOR operations. Also, today's final rule has reduced the required sampling frequency to an annual basis. These changes significantly reduce the cost estimate for this source. Please see EPA's response to comment EPA-HQ-OAR-2009-0923-1011-21 for further discussion.

Comment Number: EPA-HQ-OAR-2009-0923-1167-13
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:

In summary, Noble Energy has prepared a best estimate of the proposed rule costs based on its understanding of the proposed rule requirements and experience developing GHG emission inventories. However, rule changes and clarifications upon promulgation and as yet understood external factors (e.g. limited service providers and excessive demand (i.e. industry wide, millions of emission sources would require survey, sampling, and/or measurement), and complications with field measurements and process sampling) could significantly increase the costs above these estimates. In addition rule implementation costs to develop data management and archival systems will likely result in additional underestimated burden. Many of the proposed emission estimation methodologies are cost-prohibitive and alternative simpler, streamlined methods need to be provided. Alternative, simpler emission estimation methods are discussed in sub-section C.

Finally, as noted in Comment V, EPA should provide a practical applicability screening approach for rapidly and efficiently determining Rule subjectivity based on the 25,000 tonne per year CO2e reporting threshold. The inability to determine rule applicability with a reasonable degree of certainty will require emission estimations for numerous small facilities to ensure compliance certainty. This significantly adds to the regulatory burden and it does not appear EPA has considered these costs for this rulemaking

Response: Please see EPA's response to EPA-HQ-OAR-2009-0923-1167-11 for a response to the commenter's best estimate of the costs. The Agency also agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the Preamble to today's final rule. Finally, see EPA's response to EPA-HQ-OAR-2009-0923-1151-106 for information about the costs for data management and archiving.

Comment Number: EPA-HQ-OAR-2009-0923-1167-4
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

<u>Comment Excerpt Text:</u>
The GHG emission estimation requirements in the Proposed Rule are overly burdensome and EPA has not provided data quality objectives to justify the extensive costs. To address these issues, Nobles recommends that the Proposed Rule revisions to reduce burden while collecting GHG emissions data to develop a representative inventory that is no less useful include: removal of insignificant emission sources; reducing the frequency of emission and process measurements; adapting simpler, more cost-effective emission estimation methods; and representative sampling of large source populations.

Noble's cost estimate for rule implementation concluded the EPA cost estimates for rule implementation are more than an order of magnitude low and that many proposed emission estimation methodologies are cost-prohibitive. EPA has not defined or provided inventory or data quality objectives to justify these extensive costs.

Response: Please see EPA's response to EPA-HQ-OAR-2009-0923-1167-11 for a response to the commenter's cost estimate. In addition, EPA disagrees with the commenter's statement that the Agency did not discuss data quality objectives. See the Economic Impact Analysis, in particular Section 3.4, for relevant discussion.

Comment Number: EPA-HQ-OAR-2009-0923-1174-2
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text:
While Devon strongly supports environmental and public health protection, we are highly concerned that this proposed reporting rule will impose an unnecessarily high cost to our industry for minimal air quality benefit. As a matter of fact, our internal economic impact analysis of this proposed rule indicates that the estimated cost to Devon, without contingency, is $28 million. The cost to Devon alone exceeds what the EPA has estimated ($27.7 million) for the entire US Oil and Gas industry!

Imposing costs of this magnitude on an operator results in an equivalent reduction of capital investment which results in fewer wells drilled, less clean burning natural gas produced, fewer local jobs, and less revenue returned to the US Treasury from severance taxes and mineral royalty payments.

Response: EPA is unable to evaluate the commenter's compliance cost estimate of $28 million because insufficient documentation was provided to explain how this figure was calculated. For example, the commenter did not provide assumptions for the labor rate(s), labor hours, or a detailed labor description used to calculated the estimated burden. For information about the assumptions and costs estimates for today's final rule, see the Economic Impact Analysis (EPA-HQ-OAR-2009-0923). For EPA's responses to other comments about the onshore production cost estimates, see comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-105. For information about the sampling and analysis of hydrocarbon liquids in tanks, see EPA-HQ-OAR-2009-0923-1011-21; see EPA-HQ-OAR-2009-0923-1151-129 for information about reporting of produced water emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1298-4
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The proposed rule will be unreasonably burdensome and costly to small businesses, and could cause many marginal wells to become uneconomic and abandoned.

Response: Please see Section 5 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) and EPA's response to EPA-HQ-OAR-2009-0923-0053-1 for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1305-2
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Burden and Timing for Onshore Petroleum and Gas Production

The expansion of the MRR to include the entire natural gas supply chain, from dispersed wells and small facilities to distribution meter stations and city gates; tremendously expands the scope of the rule in terms of number of sites, source types, and monitoring/calculation methodologies. BP believes that the cost and burden of the rule depicted in the Economic Impact Analysis (EIA) for the newly included Onshore Petroleum and Gas Production (OPGP) category is significantly understated and should be updated prior to finalizing the rule with the OPGP category included. Our lower 48 Onshore Petroleum and Gas Production operations, composed of some 13,868 wells along with several hundred ancillary small compressors and facilities, have projected the initial 2010-2011 burden of the rule at some $23.6 MM with annual reoccurring costs of some $17 MM – excluding the costs for quarterly sampling and analysis of hydrocarbon liquid and produced water for dissolved CO2. Inclusion of the costs estimated for these two source types boosts this total to more than $40 MM. This suggests that the burden estimate of $27.7 MM in the EIA is very low. This further suggests that the amount of work necessary to implement the rule requirements also expands by about the same ratio and cannot be accomplished in the time frame contemplated in the proposed rule.

To address the balance of burden and cost with emission coverage and the program goals of informing policy along with adequate time for implementation, BP suggests the following:

- EPA should conduct a re-evaluation of the Economic Impact Analysis and rationalization of the rule requirements, rule approaches, burden, and costs vs. the amount of emissions covered for additional public comment before finalizing the GHG reporting rule for the Onshore Petroleum and Natural Gas Production sector.

Response: EPA disagrees with the comment. EPA is unable to evaluate the commenter's compliance cost estimate of $40 million because insufficient documentation was provided to explain how this figure was calculated. For example, the commenter did not provide assumptions for the labor rate(s), labor hours, or a detailed labor description used to calculated the estimated burden. Regarding the American Petroleum Institute (API) cost estimates referenced by the commenter, EPA has provided detailed responses to API explaining why their estimates are too high; see EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107 for further details. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment. In addition, see EPA-HQ-OAR-2009-0923-1151-5 for EPA's response to comments that it re-evaluated the Economic Impact Analysis and basis for rule scope and requirements. EPA adjusted the analysis in response to comments. For example, EPA included determination costs for non-reporters that will have to expend resources to determine whether or not to report. In addition, EPA updated the burden to reflect changes in today's final rule, such as monitoring of emissions sources that now have equipment thresholds for monitoring and labor hours for monitoring of equipment leaks in onshore production.

Finally, regarding concerns about the time to implement the rule, see Section II of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1305-43
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:

Economic Impact Analysis and Burden

BP participated in API's cost analysis of the proposed rule and fully supports API's analysis and conclusions - particularly for the newly included Onshore Petroleum and Gas Production (OPGP) category. Our analysis of the costs for the wells and facilities we operate suggest that API's analysis is correct and that EPA's projection of first year costs of $27.7 MM (preamble Table W-5) for this category is too low by more than an order of magnitude.

Response: Please see EPA's responses to comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-105 for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-3524-6
Organization: Chesapeake Energy Corporation
Commenter: Grover Campbell

Comment Excerpt Text:
EPA Underestimates the Cost of Complying with Subpart W.
EPA's cost estimate for Subpart W compliance is many orders of magnitude too low considering the hundreds of thousands of sources for which our industry would need to document and report emissions. EPA estimates that the costs to be incurred by onshore producers for the first year of compliance will be approximately $24,000 per reporting unit. See Table W-10, 75 Fed. Reg. at 18,629 .

To confirm the accuracy of EPA's estimate, Chesapeake conducted its own analysis for an individual reporting basin.[112] Chesapeake's analysis assumed an individual reporting basin where all operations are subject to reporting. Chesapeake reviewed the calculations and reporting requirements in the proposed Subpart W to determine the emissions from the following sources:
- Single-well pads
- Multi-well pads
- Glycol Dehydrators
- Reciprocating Compressors
- Completion Operations
- Workover Operations

Chesapeake's estimate was developed using estimates of labor rates, level of effort, and equipment rental costs. Based upon our analysis, Chesapeake calculated a first-year compliance cost of nearly $10.5 million for one representative basin - an estimate well over 400 times higher than that determined by EPA.

[112] Chesapeake acknowledges that the actual compliance costs at a given basin will vary greatly depending on the equipment operated and levels of activity.

Response: EPA has reviewed the commenter's costs, including the information they submitted to the docket and identified as confidential business information. EPA is unable to evaluate the commenter's estimate because insufficient documentation was provided to explain how the figures were calculated. The commenter has developed source categories such as *single-well pads* and *completion operations* and assigned reporting costs to each source category. However, the commenter did not disclose which emission sources to which these costs apply. In addition, the commenter did not disclose details about the labor rate, level of effort, and equipment rental costs used to estimate the compliance costs for each source category. The remainder of this response presents EPA's consideration of the information provided by the commenter.

Single and Multi-Well Pads
EPA cannot respond to the commenter's costs for single-well and multi-well pads because insufficient details were provided. Although, the commenter has disclosed the equipment at each single and multi-well pad, they did not specify EPA is uncertain what "data points" are being collected under these categories. To accurately respond to the commenter's compliance cost for single and multi-well pads, EPA would need to know, what data is being collected and how the data is being collected. See response to EPA-HQ-OAR-2009-0923-1151-5 for discussion about changes EPA made to today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component.

Glycol Dehydrators
Please see EPA-HQ-OAR-2009-0923-1151-89 90 for EPA's response to comments about the costs for glycol dehydrator compliance cost estimate and details about EPA's estimates.

Reciprocating Compressors
Please see comment EPA-HQ-OAR-2009-0923-1063-1 for a response to comments about the costs for reciprocating compressors.

Completion and Workover Operations
The comment did not distinguish between unconventional and conventional completions and workovers. Therefore, EPA cannot evaluate the commenter's compliance cost estimate for completion and workover operations. Please see comment EPA-HQ-OAR-2009-0923-1151-97 for clarification about how reporting emissions from well completions and workovers with and without hydraulic fracturing. Also, please see Section 4 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for EPA's compliance cost estimates for conventional and unconventional well completions and workovers.

Overhead, Quality Control, and Reporting Costs
Although EPA agrees with the commenter's overhead, quality control, and reporting costs per basin, EPA disagrees with the commenter's company-wide IT costs. Please see comment EPA-HQ-OAR-2009-0923-1151-106 for discussion about EPA's consideration of the costs for company-wide data management systems.

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-1
Organization: American Petroleum Institute

Commenter: Karen Ritter

Comment Excerpt Text:
First, the proposed requirements will be more costly to implement than EPA has estimated. Because they apply to vastly more industry activities and sources, EPA's cost estimates for impact on the industry are too low by an order of magnitude

Response: Please see EPA's responses to comments EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-105 for a response to this comment.

Comment Number: EMAIL-0002-10 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
EPA's estimated cost impact appears to be at least an order of magnitude low.

GPA is evaluating the economic impact of the proposed Subpart W and will compare the results to the analysis provided by EPA. However, preliminary indications are that the EPA's cost estimates are at least one order of magnitude low. EPA has failed to recognize the full impact of requiring reporting at all facilities and pipelines in the natural gas gathering and processing sector.

To demonstrate the disparity in EPA's cost estimate, the following cost estimates from one GPA member company are presented. These costs are only for this one company, an independent gathering and processing company with no production. Their estimated first year costs for initial implementation of the proposed Subpart W are approximately $80 million and their ongoing annual costs for recording, measuring, calculating, and reporting are estimated to be $9.5 million. To emphasize, these are the estimated costs for only one GPA member company to comply with the proposed Subpart W. This compares to EPA's estimate for all companies in all segments of the natural gas industry covered by Subpart W of $56 million for the first year costs and $21.4 million for ongoing annual costs.

Response: EPA disagrees that the proposed rule's cost are at least an order of magnitude low. EPA is unable to evaluate the commenter's estimate for one facility—$80 million year one and $9.5 million in subsequent years—because insufficient documentation was provided to explain how these figures were calculated. For example, the commenter did not provide its assumptions for the cost of each monitoring activity per source or how these were extrapolated.

However, EPA has made several clarifications and revisions that will reduce the burden on processing reporters, as described in Preamble Section II.F. For instance, EPA has decided not to include gathering lines and boosting stations as an emissions source in subpart W at this time, see comment response EPA-HQ-OAR-2009-0923-1206-13. Second, today's final rule clarified that reporters may conduct an annual measurement of each compressor in the mode as it exists at the time the annual measurement is taken, with shutdown depressurized mode monitored for each compressor at least once every three years. Please see “Compressor Modes and Threshold” in EPA-HQ-OAR-2009-0923. Third, today’s final rule does not require tank emission calculations for natural gas processing.

See also the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) for more information about EPA’s estimates of today’s final rule’s cost for the average natural gas processing facility. Finally, this commenter submitted additional comments and cost estimates to the docket; see EPA-HQ-OAR-2009-0923-1206-25 for EPA’s response.

Comment Number: EPA-HQ-OAR-2009-0923-0049-7
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
For purposes of these comments, we will assume that “optical gas scanning” refers to infrared cameras, which cost between $80,000 and $100,000 each to purchase, or about $2,500 per week to rent. We also will assume that EPA means to include industrial and commercial customer meters and regulators, but not residential meters, within the term above ground M&R station.

To evaluate the burden of Subpart W, AGA conducted a survey of our members to determine how many above ground M&R stations would be affected by the proposal. The results are somewhat difficult to interpret, because it became apparent that our members are very confused by EPA’s undefined term. Some thought it included residential meters, other thought it only included industrial and commercial meters, and all questioned whether metering and regulating for smaller commercial customers such as fast food restaurants and medium box stores would be included. The survey will need to be refined, once EPA provides clarification regarding the scope of this term, but the current survey indicates that our member LDCs have an average of 19,000 M&R stations per company that would be affected by this proposed annual infrared camera leak survey requirement. Our members estimate that they can visit less than 10 M&R stations per day to perform a leak survey. As a result, the Subpart W leak survey proposal could easily require each company to purchase or rent 50-100 infrared cameras to get the survey work done within about a two month timeframe each year, beginning in 2011. As a result, it could easily cost a single LDC $4,000,000 to comply with this leak survey requirement in 2011. In addition, there are not enough cameras or trained operators to supply this demand, so market forces would likely increase costs further. EPA asserts that LDCs would be able to outsource their optical scanning needs by contracting with consulting firms. However, there are also not enough cameras or trained operators within consulting firms to serve this level of demand.

EPA estimates in the preamble to the proposed rule that the entire natural gas distribution sector – all affected LDCs in the United States – would incur only $1.6 million as the first year cost for reporting fugitive and vented emissions under all provisions of the Subpart W proposal. In contrast, we estimate that a single average AGA member LDC could incur about $4 million in the first year – to comply with a single provision in the Subpart W proposal. EPA has clearly misunderstood the impacts of this rule and has vastly underestimated the cost of providing the information EPA seeks.

Response: As described in Section III.B of the preamble to today's final rule, EPA has reviewed a number of comments concerning the proposed rule's cost of compliance and disagrees these costs are vastly underestimated. Regarding EPA's response to the commenter's assumption that the rule would apply to customer meters, the requirements do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps. See preamble Section II.F for a complete discussion about the meters EPA intended to include in the rule. EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 discusses the costs associated with the meters EPA intended to include in the rule.

EPA finds the commenter's estimates of the costs for each camera to be reasonable. EPA estimated the overnight capital cost for each camera to be $100,000, which is at the upper bound of the GPA cost range of $80,000 to $100,000. However, EPA disagrees with the commenter's assumptions about the extent of requirements for leak detection. EPA estimates that each LDC will be required to monitor between 32 and 215 metering and regulating stations, a small fraction of the 19,000 metering and regulating stations assumed by this comment. As discussed in Preamble Section III.B and in comment EPA-HQ-OAR-2009-0923-1016-11, the commenter based its cost estimate on a much higher number of metering and regulating stations because it assumed that Subpart W leak detection would apply to all customer meters as well as meter and regulator stations at which custody transfer does not occur.

Regarding the commenter's concerns about the optical scanning needs under the rule, EPA has revised today's final rule and is including the option to use Method 21 and infrared laser beam illuminated instruments to detect leaks for sources that are accessible, as described in Preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-0053-5
Organization: Cardinal Engineering, Inc.
Commenter: Kristine D. Baranski

Comment Excerpt Text:
Although the commenter appreciates that there are concerns with obtaining comprehensive data, the direct inspection cost involved with optical gas imaging is extremely high .
The cost is high when one considers that the output is qualitative (as compared with a ppm "leaking" threshold obtained via the OVA/TVA monitoring methodology as currently practiced in LDAR programs) .

Response: EPA agrees with the comment that in certain situations, using handheld leak detection devices may be more cost effective. Hence, EPA has revised today's final rule and is including the option to use Method 21. Please see Section II.E of the preamble for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0837-9
Organization: Canadian Gas Association
Commenter: Michael Cleland

Comment Excerpt Text:
In the rule preamble (tables W-S and W-6, p. 89), EPA estimates costs first year costs for LDCs to implement the rule at $0.07 per tonne in the first year, dropping to $0.04 per tonne in subsequent years. Based on Canadian LDC experience in monitoring and reporting, we are unable to come anywhere near to these very low amounts.

Using Canadian data we have come up with some estimates that suggest much higher costs will be incurred.

• For example, based on field data and analysis conducted since 1995, the default emission factor for a gate station equates to 22.4 t CO2e per station.[113] At $0.07/tCO_2e, the per gate station measurement budget equates to $1.57.

• Through the CGA's CEPEI group, the downstream natural gas industry has collaborated on compiling a national GHG inventory for some years. Based on the most recent year that national data were compiled (the 2007 inventory year), fugitive emissions from the distribution sector in Canada totaled 890,000 t CO2e, which represents 0.1 % of Canada's national inventory in 2007.

[113] Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System prepared for Canadian Energy Partnership for Environmental Innovation by Clearstone Engineering, calculation Form 3.2.1+10, p. 49 (September, 2007); the emission factor has been converted to tones CO2e based on gas composition data from Ontario.

This amount represents the emissions reported by Canada's 12 main LDC operations[114], an average of 74,200 t CO2e per company. At $0.07 pert CO2e, this equates to an average cost per company of $5,200 , an amount which could not reasonably cover the field survey work, "administrative costs reviewing the reporting rules, training personnel, documenting emissions data and emissions estimates, approving the submission to the EPA, submitting reports and maintaining records"[115] that EPA has included in its cost estimates.

Response: Overall, EPA disagrees that the Agency underestimated the rule's compliance costs, and the distribution segment in particular, as described in the response to comment EPA-HQ-OAR-2009-0923-1016-4. The remainder of this response discusses details unique to this comment.

First, EPA disagrees that each reporter's per gate station measurement budget equals $1.57. While EPA estimated an average compliance cost of $0.07 per metric ton CO_2e for the distribution segment in the proposed rule, this average does not represent the costs associated with individual activities within that segment. For instance, the per metric ton CO_2e cost will be higher when leak detection is conducted; the per metric ton CO_2e cost will be lower for monitoring activities that rely on a population emission factor is required.

Furthermore, EPA disagrees with the commenter's estimated average cost per company of $5,200. EPA's cost estimates are based on the analysis of the distribution segment in the United States; application of EPA's estimates to jurisdictions outside the United States may not be appropriate or accurate. For instance, in the proposed rule, EPA estimated the average emissions per LDC to be approximately 159,000 metric tons, which is more than twice as high the commenter's estimated average emissions per LDC. EPA analyzed the costs of compliance for natural gas distribution and has revised the estimated cost of compliance in today's final rule for the average reporter to be $0.09 per metric ton and $13,854 per LDC for the first year. Further comment on this topic is available in Section III.B, of today's preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1004-1
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

<u>Comment Excerpt Text:</u>
NGSA believes that the proposed Subpart W will cause formidable financial and administrative burdens without contributing appreciably to the coverage or accuracy of emissions monitoring under the Mandatory Reporting Rule. In these comments, we discuss several ways in which the proposed Subpart W should be modified to better reflect the realities of monitoring GHG emissions in the natural gas production sector.

Response: EPA does not agree with this comment; please see EPA-HQ-OAR-2009-0923-1004-4 for a response to this comment.

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[114] These companies represent almost the entire LDC sector operations in Canada.

[115] EPA Subpart W preamble - p. 87·88.

Comment Number: EPA-HQ-OAR-2009-0923-1004-4
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
The proposed Subpart W still includes highly labor-intensive and equipment-intensive monitoring methods for our sector – requiring population counts of thousands of individual components (many of which are trivial sources of emissions) at hundreds of thousands of wellheads and thousands of miles of gathering pipelines, as well as direct measurement of equipment such as rod packing vents, unconventional well completions and workovers, and wet seal degassing vents. Certain units, such as acid gas removal (AGR) stacks, are also not equipped with the metering or monitoring equipment needed to fully comply with the proposed Subpart W; numerous units will, in many cases, need to be taken offline to install the required equipment. Considering that our sector contains approximately 475,000 of wellheads alone, these measures will require massive investments in data collection on facilities (and components within facilities) that are often negligible sources of GHG emissions.

Under any reasonable set of assumptions, the cost of complying with the above requirements will far exceed EPA's estimate of only 27.7 million dollars for the entire onshore petroleum and natural gas production sector. Indeed, the American Petroleum Institute's (API) review of the rule indicated that the costs of the proposed Subpart W to the onshore petroleum and natural gas production sector alone could reach 1.7 billion dollars, or 8.44 dollars per ton CO2-e of GHG emissions. If correct, this estimate would cause the cost of the proposed Subpart W to approach the projected near-term cost of a mandatory cap-and trade program – even though the sole purpose of the Mandatory Reporting Rule is to collect policy-relevant information on GHG emissions, not impose emission controls. In addition, this figure would far exceed EPA's estimated cost-per-ton for any other sector included in the Mandatory Reporting Rule.

NGSA believes that EPA's proposed basin-level approach fails to achieve an appropriate balance between the need for GHG data with the practical and economic burdens associated with the reporting burden imposed by the proposed Subpart W.

Response: EPA does not agree with the comment. Regarding the American Petroleum Institute's estimate of the costs, as cited by the commenter, please see EPA's response to EPA-HQ-OAR-2009-0923-1151-107, which provides a summary of the cost breakdown. Regarding the commenter's statements about requirements for population counts, please see EPA-HQ-OAR-2009-0923-1151-89.

For a response to the comment on direct measurement of equipment such as rod packing vents, well completions and workovers with hydraulic fracturing, and wet seal degassing vents, see EPA-HQ-OAR-2009-0923-1151-94 and EPA-HQ-OAR-2009-0923-1151-97.
For a response to the comment that certain equipment, such as acid gas removal vents, are not already equipped with meters or monitoring devices, see EPA-HQ-OAR-2009-0923-1024-26. Regarding the commenter's statement about the basin-level approach, see EPA-HQ-OAR-2009-0923-1151-5.

Comment Number: EPA-HQ-OAR-2009-0923-1016-7
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
Further, the agency is proposing to require annual leak surveys using, costly and unnecessary optical scanning equipment that does not result in improved leak detection beyond the leak detection currently conducted by gas utilities under existing federal and state pipeline safety regulations. This proposal would impose billions of dollars in cost on gas utilities and their customers – rivaling costs under a cap and trade program – without reducing emissions. All this effort would provide no better picture of GHG emissions from this segment than is currently available in the annual EPA GHG Inventory, because LDCs would have to use outdated emission factors that tend to seriously overstate GHG emissions from natural gas distribution.

Response: As described in the response to comment EPA-HQ-OAR-2009-0923-1152-4, EPA disagrees that the costs associated with the rule would be on the order of billions of dollars. Regarding the commenter's concerns about the optical scanning needs under the rule, EPA has revised today's final rule to allow alternative options. See preamble Section II.F for details about the alternative leak detection options.

EPA also disagrees that the information gathered is duplicative with the EPA GHG Inventory. As described in EPA-HQ-OAR-2009-0923-1016-11, today's final rule will provide an estimate of "actual" emissions, as opposed to "potential" of emissions. In addition, the proposed rule's leaker emission factors for natural gas distribution are based on recent emission measurement studies conducted by Clearstone Engineering, and not the U.S. GHG Inventory. Further discussion on this topic is provided in "Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD" (EPA-HQ-OAR-2009-0923-0027).

Comment Number: EPA-HQ-OAR-2009-0923-1020-6
Organization: Southwest Gas Corporation
Commenter: James F. Wunderlin

Comment Excerpt Text:
Total Cost for Process Emissions

In consideration of the above discussions, it is Southwest's opinion that the Process Emissions cost estimate described in the preamble of the proposed rule is significantly underestimated. The published cost estimate for the natural gas distribution sector is estimated to be $1,680,000 for start up and $600,000 for annual costs thereafter. Southwest respectfully suggests that these costs are more likely to be $1,680,000,000 and $600,000,000, respectively.

Response: *Note: See comment EPA-HQ-OAR-2009-0923-1020-5 for the text that precedes this excerpt from the commenter's letter.*

EPA has reviewed the proposed rule's cost estimates and disagrees that the Agency significantly underestimated the costs for the natural gas distribution segment. Based on the limited information that the commenter provided regarding the basis for their estimate, EPA has determined that the commenter assumed that leak detection is required for all regulator stations. Please see the response to comment EPA-HQ-OAR-2009-0923-1016-11 for detailed discussion about why this assumption is inconsistent with EPA's intent.

EPA is unable to further evaluate the commenter's estimates ($1.68 billion and $600 million) because insufficient documentation was provided to explain how these figures were calculated. For example, although the commenter specified their assumption about the cost of infrared laser detector instruments, they did not identify the other assumptions and calculations underlying its estimate, such as labor involved. EPA estimated the capital cost of an optical gas imaging instrument to be $100,000, similar to the cost estimated by the commenter. However, the commenter assumed they would purchase the instrument and did not specify whether they considered the lowest cost option that EPA analyzed. EPA assumed that reporters would use contractors to conduct emissions detection activities; the contractors would purchase the instrument and pass on the costs to as many facilities as they can provide service to each year and it was unclear if the commenter agreed with these assumptions or not because they did not indicate they considered this option. EPA modified this analysis in the final Economic Impact Analysis based on the revision to today's final rule that allows alternative leak detection methods. For details about the alternative leak detection methods, see preamble II.E; the response to comment EPA-HQ-OAR-2009-0923-1016-11 provides details about the associated costs.
Finally, the commenter provided an estimate to conduct a component inventory that appears to have contributed to the total cost estimate. See EPA-HQ-OAR-2009-0923-1016-11 for a response to assumptions about component inventories. .

Comment Number: EPA-HQ-OAR-2009-0923-1039-25
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Discussion of Implementation Costs

Based on information provided in EPA's Economic Impact Analysis (EIA), the annual cost per affected facility for measurement and monitoring in subsequent years (i.e., after the first year of reporting) is approximately $16,000. This total includes stationary combustion source reporting that will be required upon Subpart W promulgation. For small to average-size facilities without complicated measurements, INGAA generally agrees with the estimated subsequent year costs. However, the EPA cost analysis did not adequately account for all required and potential costs, including the following:

• Additional first-year reporting costs. First-year per-facility costs presented in the EIA are only about $1,700 more than subsequent year per-facility costs. Additional first-year tasks would be required, including a more detailed assessment of applicability and requirements; monitoring plan development, including standard operating procedures for measurements; equipment calibrations; measurement criteria definitions; identification of vent access measurement issues and sample port installations; calculation and recordkeeping documentation development (e.g., spreadsheets and database support); operator and technician training; data review/QA-QC procedures; reporting tool development and integration with EPA's pending web-based reporting system; and, additional management oversight. INGAA understands that some tasks would be company-wide and shared by numerous facilities. However, implementing a program to comply with a rule of this breadth and complexity would likely entail costs an order of magnitude or more greater than EPA's estimate for the initial reporting year.

•Three-mode testing costs for reciprocating compressors. As discussed in Comment V, emission measurements must be conducted for each compressor in each of three operating modes that occurs within the year, including operating, standby-pressurized, and not operating-depressurized. This requirement will be considerably more complex than simply testing each compressor in a single as-found condition. One approach would be to cycle each compressor through the three modes during a test team visit. However, this would complicate compressor station operation (i.e., coordination with dispatch), possibly disrupt gas transmission service, and would most likely create an unnecessary venting event for each compressor that requires a blowdown which wastes product and increases GHG emissions. Alternatively, a test team could be placed on standby while each compressor naturally cycles through the three modes or could revisit the compressor station numerous times; or, operators could be trained to perform measurements when the opportunity arises. Each of these approaches creates its own complications and expense. It does not appear that the EPA analysis accounts for the costs associated with the complexities of three-mode testing.

• Testing complexity for "inaccessible vents". Many compressor vents, such as reciprocating rod packing and centrifugal wet seal oil degassing, are located above rooflines since facilities were not constructed with vent access in mind. Such vents would be deemed "inaccessible" in many cases under typical LDAR programs. Accessing these vents to measure flowrates typically requires a manlift and could require assessment and implementation of additional safety precautions (e.g., by-passing high-pressure gas lines, avoiding personnel exposure to an emergency blowdown event, etc.). These requirements will add time and expense to measurements, especially for three-mode testing of reciprocating compressors.

• Small facility testing to validate non-reporting status. If a method to screen facilities for rule applicability (i.e. 25,000 metric ton CO2e threshold) is not defined or if the screening method is too conservative, then the number of facilities required to conduct first year measurements will increase. For the 25,000 metric ton threshold, EPA estimates that 1,145 of 1,944 transmission compressor stations and 133 of 397 natural gas storage facilities will be required to report GHG emissions. Without an accurate applicability screening method, first- year testing costs could increase significantly – and may encompass all facilities – to confirm emissions from facilities required to report and validate status of smaller facilities not subject to the rule

Response: EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact

Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.
On the other hand, EPA disagrees that the first year cost estimates should be an order of magnitude greater. As discussed in the Economic Impact Analysis and Preamble Section III, the inclusion of reporting costs increased EPA's estimate of total private sector costs compared to the April 2010 analysis, but the order of magnitude remained the same. EPA included similar first year costs to the commenter in the proposed rule, such as registration; regulation review, monitoring plan development; equipment; monitoring and measurement, training, documentation, reporting, auditing, and archiving. As noted above, determination costs have been added to this list I today's final rule, determination costs have been added to this list.
EPA did not intend for reciprocating or centrifugal compressors to be taken offline in order for reporters to collect the operational mode data required under subpart W. Therefore, as described in Preamble Section II.F, EPA has clarified the today's final rule to allow reporters to conduct an annual measurement of each compressor in the mode as it exists at the time the annual measurement is taken, with shutdown depressurized mode monitored for each compressor at least once every three years. For more detail, please see "Compressor Modes and Threshold" in the docket (EPA-HQ-OAR-2009-0923).

EPA considered the comment concerning monitoring of inaccessible compressor vents, and disagrees with the comment on testing complexity because the proposed rule allows installation of a port on the vent line for insertion of a temporary meter, and these ports can be installed at ground level. Additionally, in today's final rule, reporters may now use acoustic leak detection devices to estimate through-valve leakage from unit valves and blowdown valves. Please see Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1039-3
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Applicability Determination Costs and Burden

In discussing the Proposed Rule implementation schedule, EPA assumes that many reporting entities already have GHG monitoring capability due to the requirements of other air quality programs. This assumption is not valid for natural gas transmission and storage systems, which have never been subject to direct measurement of vented emissions or fugitive emissions monitoring, as required in the Proposed Rule. Natural gas transmission and storage facilities do not have currently-installed mechanisms or data systems for monitoring and measuring fugitive or most vented fugitive emission sources as called for in the Proposed Rule. For INGAA members, the task of determining whether GHG reporting is required for specific facilities under Subpart W would represent a significant departure from current practices, requiring considerable time and resource allocations.

In reviewing EPA cost estimates, INGAA generally agrees with the per facility monitoring costs for years subsequent to the initial year. However, that cost does not consider important logistical factors such as vent access safety issues, three-mode testing, and availability of service providers, which will escalate per-facility costs. In addition, EPA cost estimates do not consider costs associated with measurement and monitoring at smaller facilities to determine their need to report; therefore, cumulative costs are significantly underestimated. For natural gas transmission and storage, EPA estimates that 59% of 1944 compressor stations and 34% of 397 underground storage facilities will exceed the reporting threshold [see 75 FR 18618], and approximately 1060 facilities (or 45%) would not report for these two industry segments. However, as noted above, absent a screening method, these facilities would still be faced with vent measurement, leak monitoring, and population counts for pneumatic devices and storage wellhead components to estimate facility GHG emissions and document that total facility emissions are less than the threshold, in essence to provide a “negative determination” relative to the 25,000 metric ton CO2e threshold. Thus, with an additional 45% of facilities that do not report still required to conduct monitoring (e.g., leak surveys) and direct vent measurement, the cumulative costs would be nearly double EPA’s estimate.

In addition, the number of available service providers and qualified technicians is limited, and monitoring and measurement are required for many segments in Subpart W. Thus, the added need to monitor at smaller facilities would exacerbate this shortage, and market pressure could escalate per-facility costs. This shortage could also compromise the ability of operators to meet the Proposed Rule schedule and is one of several factors contributing to the need for a phased approach for reporting. In addition, the Proposed Rule compromises compliance certainty due to the uncertainty associated with GHG estimates for fugitive emissions and some vented sources.

The Proposed Rule essentially requires that Subpart W emission estimation methods (monitoring and direct measurement) be applied to every natural gas transmission compression facility and natural gas storage facility, every year. These requirements would not only increase the cost of Subpart W, but also negate the administrative and cost advantages that EPA sought to achieve by selecting a 25,000 metric ton CO2e threshold. In conclusion, a screening method that provides reasonable compliance certainty is needed to avoid unnecessary compliance risk, implementation complexity, and financial burden

Response: EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA’s complete response in Section III.B.2 of the preamble to today’s final rule. In addition, today’s final rule allows reporters to request the use of best available monitoring methods under certain conditions, such as lack of service providers and qualified technicians; please see the response to EPA-HQ-OAR-2009-0923-1011-27 for further details. Also see response to EPA-HQ-OAR-2009-0923-1039-25 that addresses the commenter’s concerns about vent access safety issues and three-mode testing.

Comment Number: EPA-HQ-OAR-2009-0923-1045-4
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

<u>Comment Excerpt Text:</u>
Impact on Local Distribution Companies

Several commenters have indicated that the proposed Subpart W will place an onerous burden on local distribution companies (LDCs), with a financial impact as great as $4,000,000 per LDC. While we agree that the coverage of LDC systems under Subpart W is in need of clarification, we do not believe that EPA intended the coverage of LDC systems to be as sweeping as these commenters suggest, and believe that EPA can proceed to require OGI for emission detection at city gate stations and above ground district regulators. In addition, we believe it is advisable for EPA to require OGI emission detection at certain underground pipeline main facilities and large customer metering and regulating stations, albeit on a "phased in" timetable.

1. Proposed LDC Coverage of Subpart W is Manageable and Cost-Effective. Although the proposed definition of LDC facilities, which refers broadly to "above ground meter regulators and gate stations,"[116] is ambiguous, we do not believe EPA intended for the proposed Subpart W to have such broad coverage as to impose an OGI inspection requirement on residential meters and small commercial establishments. As EPA explains in the preamble to the proposed rule:

> "Distribution system CH_4 and CO_2 emissions result mainly from fugitive emissions from above ground gate stations (metering and regulating stations), below grade vaults (regulator stations), and fugitive emissions from buried pipelines."[117]

EPA's view that gate stations, below grade regulator stations, and buried pipelines are the main contributors to GHG emissions from LDC systems is supported by the data provided in Appendix A of the Technical Support Document accompanying the proposed rule. The TSD, and the preamble, do not mention requiring OGI detection or emission factor estimates for any customer-specific metering facilities.

Assuming that EPA intended for Subpart W to have this more limited scope, we believe that the proposed rule could be easily implemented at reasonable cost. Based on our inquiries with a local distribution company serving a large city in the Northeast, the number of above-ground city gates and district regulator stations should be manageable even for a large metropolitan area. The utility we consulted has 20 city gate terminals which meter and reduce the pressure from transmission pipeline(s). The utility also has 150 district regulators which operate downstream from the city gate terminals and reduce pressure and re-distribute the gas to the lower pressure gas distribution system. These stations are housed in underground spaces, underground manhole vaults and in small above ground buildings and sometimes within the gate station itself. The system in our survey has only 6 district regulators below ground.
A summary of estimated costs to survey these locations is presented below:

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[116] Proposed 40 C.F.R. § 98.230(a)(8).

[117] 75 Fed. Reg. at 18,617

Component	Number of Locations[7]	Hours to Survey[8]	Total Hours	Consultant cost[9]
Above ground gate stations	20	4	80	$30,000
Above Ground District Regulators	144	2	288	$108,000
Below grade vault District Regulators	6	2.5	15	$5,625
Totals	**170**	**8.5**	**383**	**$143,625**

Based on this survey, we suggest that the costs associated with using OGI at gate stations and district regulators is nowhere near the multimillion dollar annual expense suggested by some commenters. Moreover, finding and repairing leaks would yield savings for LDCs and ratepayers – possibly enough savings to more than pay for the consulting services or equipment and program implementation costs.

FLIR Systems also disagrees with EPA's assumption that emissions from underground vaults cannot be detected using OGI, and must therefore be estimated using population emission factors. FLIR Systems has successfully deployed OGI at underground vaults by lowering OGI equipment through the same access points used for maintenance and repair of the systems within these vaults. Given that below-grade regulator stations are both manageable in number and capable of being monitored using OGI, FLIR Systems recommends that EPA consider proposing the use of OGI for detection of fugitive emissions from underground vaults.

Response: EPA agrees that the costs for optical gas imaging are well below the multimillion dollar estimates. EPA also generally agrees with the number of station locations per LDC; however, the Agency did not intend to require surveys for non-custody transfer stations and has clarified today's final rule (see preamble II.F). In addition, the comment did not provide sufficient information for EPA to respond in detail to the number of hours required per station. For instance, while the commenter estimates four hours to survey an above ground gate station, including 45 minutes travel time between stations and time to prepare reports, it is unclear how much time is allocated to survey each station compared to preparing reports. In addition, the data presented by the commenter suggest that the cost for consultants is $375 per hour. EPA disagrees with this hourly rate; in today's final rule, EPA has applied labor rates that are significantly lower than that assumed by the comment: from $55.20 per hour to $101.31 per hour, as described in Section 4 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923). In today's final rule, EPA has revised the estimated cost of compliance for the average reporter to be $0.09 per metric ton and $13,854 per LDC for the first year. See EPA-HQ-OAR-2009-0923-1036-11 for a detailed discussion about EPA's assumptions and cost estimates for leak detection surveys.

Finally, EPA disagrees with the commenter's characterization of the Agency's assumptions in the proposed rule for leak detection in metering and regulating underground vaults. EPA did not assume that equipment leak emissions from underground vaults cannot be detected using optical gas imaging instruments. Rather, EPA determined that underground vaults can be difficult to access, and equipment leak emissions detection at underground vaults can be burdensome. Therefore, today's final rule requires the use of population emission factors.

Comment Number: EPA-HQ-OAR-2009-0923-1098-2
Organization: Southern Union Company
Commenter: Charles Wait

Comment Excerpt Text:
SU wishes to emphasize a few of the major issues that our company faces. First, SU urges EPA to consider the INGAA proposed screening method. SU believes that only 60-65 percent of its stations have greenhouse gas (GHG) emissions greater than the reporting threshold. However, absent a screening methodology in the final rule, SU feels obligated to devote precious resources to monitoring stations to prove a negative applicability. These include stations where total GHG emissions could be as low as 5,000 mT CO2e.

Response: EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1099-10
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Component count of fugitive emissions sources - Section 98.236.c.19 is confusing. Does this section require us to do a component count of all our facilities regardless of whether they are leaking? If this is EPA's intention, this would be very burdensome and costly. Each of our distribution meters for example has approximately 100 connectors alone. This data is not currently compiled in any database. Therefore, to comply with this reporting requirement we will have to conduct a survey of all our meters (270 to 500,000 depending on the definition) and count all the components. We would need to employ hundreds of people for several months to accomplish this. Why is this data required? And what exactly does EPA want us to report?

Response: Today's final rule does not require a component count regardless of whether they are leaking; rather, today's final rule requires the counting of only leaking components. Also, the rule does not require monitoring of all meters from natural gas distribution reporters; only leaking components at above ground city gate stations at custody transfer have to be counted and reported to EPA. See preamble Section II.F for a complete discussion about the meters EPA intended to include in the rule. In addition, see EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 for a discussion that clarifies the component count requirements under today's final rule and for discussion about the costs associated with the meters EPA intended to include in the rule.

Finally, EPA has required reporters to monitor emissions from above ground metering and regulator city gate stations at which custody transfer occurs because these sources contribute significantly to the total national emissions for the industry. See the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) for complete discussion, including how EPA identified the major emissions sources and why those emissions are subject to today's final rule. Furthermore, preamble III.E to today's final rule explains the purposes the reporting of emissions under Subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1099-8
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Third, the infrared cameras are very expensive and not very plentiful. It will be difficult to comply with this requirement regardless of whether consultants perform the work or we do the survey in house. There are not enough cameras available or consultants capable of doing the survey considering the number of existing M&R stations (270 city gate stations and over 500,000 M&R stations, depending on your definition). Even if EPA did not intend to include residential meters in your definition of M&R, surveying even 270 city gate stations would be time consuming and costly.

Response: EPA has revised today's final rule to allow alternative options. See preamble Section II.F for details about the alternative leak detection options.
In addition, as described in EPA-HQ-OAR-2009-0923-1016-11, EPA has clarified that the rule does not apply to customer meters, i.e., residential, commercial and industrial meters, served by existing metering and regulating stations.

EPA reviewed its cost estimate and disagrees that surveying above ground city gate stations at custody transfer would be overly time consuming and costly. Today's final rule allows reporters to request the use of best available monitoring methods under certain conditions, such as such as lack of cameras or consultants capable of doing leak surveys; please see the response to EPA-HQ-OAR-2009-0923-1011-27 for more information about use of best available monitoring methods. As outlined above, today's final rule has clarified that leak detection is only required at above-ground city gate stations with custody transfer and has revised today's final rule to allow alternative methods of leak detection; therefore, far fewer resources are required to meet the requirements of the rule than assumed by the comment. Furthermore, EPA is unable to evaluate the commenter's total estimate because insufficient documentation was provided to explain how these figures were calculated. For example, the commenter did not specify their assumptions about time required to perform leak detection at a metering and regulator station, how many and what level staff members are necessary, what equipment must be purchased, or what contractor costs would be incurred. Nonetheless, EPA has inferred that a large part of the commenter's cost estimate can be attributed to the misinterpretation that customer meters are subject to leak detection requirements. The requirements do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps. See preamble Section II.F for a complete discussion about the metersEPA intended to include in the rule. EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 discusses the costs associated with the meters EPA intended to include in the rule.

Comment Number: EPA-HQ-OAR-2009-0923-1152-4
Organization: Consumer Energy Company
Commenter: Amy Kapuga

Comment Excerpt Text:
EPA Has Vastly Underestimated Costs – Changing or Eliminating the Annual Leak Survey Proposal Would Help Reduce Compliance Costs Substantially

EPA is estimating a per company cost of $11,188 in the first year and about $7,000 per year per LDC thereafter. In contrast, Consumers estimates the cost of complying with the leak survey requirement in the rule will be more on the order of $1,000,000 per year, or more. EPA has seriously underestimated the cost of complying with the 2010 Proposal, for at least four reasons.

* First, the 2010 Proposal uses the undefined terms “above ground meter regulators” in sections 98.232 and 98.233[118], and “metering stations and regulating stations” in section 98.238 (defining a natural gas distribution facility) that could be interpreted to include not only city gates and large custody transfer or district metering and regulating (M&R) stations, but also industrial, commercial and even residential customer regulating and metering equipment. We do not believe this was EPA’s intent, but unless the term is clarified, regulatory uncertainty and the risk of varying interpretations by field enforcement personnel would drive LDCs to include all customer meters in their leak surveys and reporting. When multiplied by each customer meter, the significant annual leak survey costs would result in millions of dollars of unnecessary cost to Consumers and our customers.

* Second, the agency has underestimated the cost of conducting an annual leak survey of the eight listed components using optical scanning equipment at distribution city gates, above ground meter regulator stations and at underground storage facilities. Requiring the use of infrared cameras significantly increases this cost.

* Third, we do not have inventories or records for all eight of the components listed in section 98.232(f)(5) and (i)(1). We would have to visit each meter and regulator location (depending on the definition of M&R) to develop the list required for applying component-level emission factors to component counts. The burden of this proposal could be reduced significantly by reducing the number of components and better defining them so it is clear what is to be included. The burden could be eliminated by allowing the use of facility-level emission factors for city gates and above ground M&R facilities, as EPA has proposed for below-ground M&R facilities and vaults.

* Fourth, EPA has underestimated the costs making an initial threshold determination for small distribution systems and other small facilities that likely fall below the threshold. These facilities

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[118] Proposed 40 C.F.R. §§98.232.(i), 98.233(q)(7), 75 Fed. Reg. 18637, 18643.

apparently would have to conduct a full leak survey using optical scanning in the first year in order to determine whether a distribution, underground storage, transmission compression facility or LNG facility does or does not exceed the 25,000 tpy regulatory threshold under §98.2(a)(2). EPA could avoid this burden by allowing small facilities to use a simpler threshold determination method that does not require leak surveys or other field work.

1. Because M&R is Not Clear Defined and Could Apply to Customer Meters, Distribution M&R Leak Survey Costs Could be Extremely Burdensome and Costly

Even without requiring infrared cameras, EPA's annual leak survey requirement would impose far greater costs than it has estimated, largely because the proposal could be interpreted to apply to customer meters. The cost of employee time for visiting each site is not large, but when multiplied by each meters, the costs expand exponentially.

2. Optical Scanning/ Infrared Camera Costs

EPA explains in the preamble to the 2010 Proposal that "EPA proposes conducting fugitive emissions detection and then applying leaking component (or leak only) emissions factors for processing, transmission, underground storage, LNG storage, LNG import and export terminals, and LDC gate stations."[119]. Proposed section 98.233(q) requires LDCs, and other facilities subject to Subpart W, to use the methods described in 98.234(a) to "conduct an annual leak detection of fugitive emissions" from the relevant list of components in §98.232.[120]

Consumers requests that EPA revise sections 98.232, 98.233 and 98.234 to clarify that the term "Natural Gas Distribution Facility" does not include customer meters and that LDCs are not required under Subpart W to leak survey or report fugitive emissions from industrial, commercial and residential customer meters.

Response: EPA disagrees that it underestimated the rule's cost for natural gas distribution reporters. EPA determined that the commenter overestimated the cost based on assumptions that were inconsistent with the intent of the rule. Response to comment EPA-HQ-OAR-2009-0923-1016-11, clarifies that monitoring requirements do not apply to customer meters, and that leak detection requirements do not apply to all metering and regulator stations.

In addition, EPA did not intend to have reporters count the leaking components from all stations and meters. See EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 for a discussion that clarifies the component count requirements under today's final rule and why EPA has elected not to use facility-level emissions factors for city gates and above ground M&R facilities.

EPA agrees that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.

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[119] 75 Fed. Reg. at 18622.

[120] 75 Fed. Reg. at 18642.

Regarding the commenter’s concerns about leak detection equipment, see preamble II.F for details about alternative leak detection options .

Comment Number: EPA-HQ-OAR-2009-0923-1154-10
Organization: Latham & Watkins LLP on behalf of DCP Midstream
Commenter: Matthew C. Brewer

Comment Excerpt Text:
The High Cost and Extreme Burden Underscore The Lack of Justification for “Super” Source Aggregation

EPA’s estimate of the cost for reporting fugitive and vented emissions for all companies in all segments of the petroleum natural gas industry covered by Subpart W is $56 million for first year costs and $21.4 million for continuing annual costs. See Proposed Rule, Tables W-5 and W-6, at p. 18625. As discussed below, DCP estimates that its first year costs alone, even without the proposed “super” source aggregation, would be almost $63 million and thus exceed EPA’s estimate for the entire industry. Moreover, if EPA finalizes its proposed “super” source aggregation, DCP’s total capital costs to comply with the Rule would be over $200 million, or almost four times EPA’s estimate for the entire industry. Thus, EPA has significantly underestimated the burden that would be placed on the processing sector were it required to collect the information necessary to comply with the Proposed Rule.

A specific example of EPA having underestimated the costs of complying with the Proposed Rule is the cost associated with the metering that the Proposed Rule would necessitate. [FN 26 - Table 1 of these comments identifies the Proposed Rule’s Sections that, based on DCP’s interpretation, require the use of meters.] According to the Background Technical Support Document, it appears EPA assumed a cost of $1,400 per meter for a simple pitot, annubar, or rotometer. In many cases, however, these meters are not adequate devices for these applications. Rather, DCP Midstream believes orifice plate meters and roots meters are necessary for these metering requirements. Table 1 below provides DCP’s estimates of its costs associated with installing and operating the meters necessary to comply with the Proposed Rule. In addition to the purchase price of the meter, DCP Midstream has factored in costs associated with installation, outage time, straight pipe run requirements, and transmitting data to the company’s data collection system.

Under a non-aggregation “source” approach, DCP estimates that, at a minimum, most or all of its 48 processing plants and treaters and about 24 compressor stations, or 72 total sources, would exceed the 25,000 tpy CO2e threshold when Subpart C emissions are combined with Subpart W emissions. As detailed in the Table 1 below, DCP estimates its capital costs to monitor these “major” sources at approximately $63 million. Under EPA’s proposed “super” source aggregation, an additional 630 of DCP’s compressor stations, whose individual emissions fall well below the 25,000 tpy CO2e threshold, would become subject to the reporting requirement. DCP estimates that its total costs with the proposed “super” source aggregation would be about

$203 million, or more than $167 million over and above its costs without such aggregation.

Table 1 of these comments identifies the Proposed Rule's Sections that, based on DCP's interpretation, require the use of meters.

Table 1: Estimated DCP Metering Costs
With and Without "Super" Source Aggregation Approach

Equipment/Information Needs	Non-aggregation Source	Estimated Cost	"Super" Source Aggregation	Estimated Cost	Proposed Rule Section Leading to Requirement
# of additional acid gas flow meters req'd	35	$3.5 million	40	$4.0 million	§98.233(d)
# of compressor rod vent and wet seal degassing meters req'd	113	$11.3 million	813	$81.3 million	§98.233(o) §98.233(p)
# of compressor gas volume meters req'd	480	$48 million	1,180	$118 million	§98.236(a)(17) §98.236(a)(18)
	Total	$62.8million	Total	$203.3 million	

Thus, the Proposed Rule's "super" source aggregation would cost DCP alone an additional $167 million in first year capital costs.

In addition to the enormous capital costs, DCP estimates that its annual operating costs to comply with the Proposed Rule's "super" source aggregation would be approximately $6.5 million dollars, which is almost one third of EPA's estimate of $21.4 million for the entire sector. The $6.5 million figure represents a more than three-fold increase in annual operating costs over and above the $2 million per year DCP estimates it would cost to comply with the Rule were EPA to apply the CAA's longstanding non-aggregation source approach.

Moreover, a disproportionate amount of DCP's additional costs to comply with the Proposed Rule's "super" source aggregation -- about $140 million -- would result from EPA's misconception about the proportion of the sector's fugitive GHG emissions that originate from compressors. This $140 million represents the difference in DCP's costs to determine emissions and from the compressor rod vents and wet seals under a non-aggregation source approach ($59.3 million) and DCP's costs to monitor such units under a "super" source aggregation approach ($199.3 million). As explained in more detail in Section VI.A of these comments, DCP believes that EPA's estimate that 48% of the sector's fugitive emissions originate from reciprocal compressors is greatly overstated. Indeed, information from another "midstream" company indicates that such emissions may comprise less than 6% of the sector's total emissions. This being the case, the additional $140 million it would cost DCP to determine emissions from all its upstream compressor station sources under the proposed "super" source aggregation approach cannot be justified.

Response: With regard to “super” source aggregation, please see “Topic 2: Aggregation of Gathering and Boosting Systems with Processing Facilities” in Volume 9 of the response to comments to today’s final rule (EPA-HQ-OAR-2009-0923). Today’s final rule does not include gathering system and boosting stations. Therefore, the commenter’s cost estimate for “super” source aggregation is not relevant.

EPA disagrees with the commenter’s estimate for metering, which was based on the use of higher-cost, optional methods. The commenter did not explain why they concluded that the meters identified by EPA—simple pitot, annubar, or rotometers—are inadequate for complying with the rule. Although EPA considered various metering options, such as plate orifice meters and root meters, EPA determined that lower cost options exist to measure emissions, such as port installation and temporary meters. Therefore, EPA based its cost estimate on port installation and temporary meters. The preamble to today’s final rule clarifies that although the installation of permanent meters are an option under the rule, temporary meters are acceptable to measure emissions from reciprocating and centrifugal compressors. In addition, reporters are not required to install a meter to determine compressor throughput; see preamble Section II.F for complete discussion about the requirements. See preamble Section III.B for detailed discussion about the costs associated with temporary meters and port installation.
Regarding acid gas removal units, EPA has revised the monitoring methods and provided several options to estimate emissions that eliminate the need for new meters at these units. Please response to EPA-HQ-OAR-2009-0923-1024-26 for further details on the flexible reporting requirements for these units.

Regarding the 48 percent contribution of reciprocating rod packing emissions from the natural gas processing segment, please see response to EPA-HQ-OAR-2009-0923-1154-6 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1154-7
Organization: Latham & Watkins LLP on behalf of DCP Midstream

Commenter: Matthew C. Brewer

<u>Comment Excerpt Text:</u>
Furthermore, EPA would appear, in large part, to rely on its overestimate of compressor fugitive emissions to justify the enormous burden that its proposed “super” source aggregation would place on the “midstream” sector. As explained in Section IV.C.3 of these comments, the additional cost to DCP of testing vent packings in upstream compressors located outside of “major” source facilities would be approximately $70 million. This cost alone is greater than EPA’s estimate of compliance costs for the entire sector and it cannot be justified in an attempt to account for what is, at best, an inadequately documented proportion of fugitive emissions, and that in fact may be less than 6% of total sector emissions.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-1154-10 for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1156-14
Organization: Laclede Gas Company
Commenter: Steve Donatiello

<u>Comment Excerpt Text:</u>
As has been emphasized throughout our comments, any type of gas leak, whether from rod packings or any other system component, represents a potential safety issue that gas system operators view seriously and address promptly. Volumetric leak testing on each of these units is difficult at best, and in Laclede's view, is not a good use of already-stretched customer dollars and labor resources.

Response: EPA disagrees that monitoring is an inappropriate use of resources EPA has required reporters to monitor emissions from reciprocating compressor rod packing units because these sources contribute significantly, about 28 percent, to the total reported emissions for the natural gas and petroleum industry. See the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) for complete discussion, including how EPA identified the major emissions sources and why those emissions are subject to today's final rule. Finally, see EPA-HQ-OAR-2009-0923-1010-2 for EPA's response to comments about its efforts to reduce the burden and costs of the rule, while still ensuring that the program yields high quality data and essential information.

Comment Number: EPA-HQ-OAR-2009-0923-1197-12
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

<u>Comment Excerpt Text:</u>
It is difficult to assess the economic burden of collecting and reporting this information. EPA's estimate for the burden on industry is orders of magnitude too low. For example, the cost of an infrared camera ranges from $80,000 to $100,000 in today's market (prior to the publishing of the final version of this rule by EPA). The cost for renting each of these cameras is about $2,500 per week. NiSource assumes that EPA definition of an M & R Station includes industrial customer meters and regulators, but not commercial and residential meters and regulators. There is no definition of "connectors" in the rule, therefore, we are unable to estimate the resources required for cost estimation and compliance.

Response: EPA disagrees that its cost estimate is orders of magnitude too low. In line with the commenter, EPA estimated a cost of $100,000 per camera. While EPA generally agrees with the commenter's assumption about the cost for an infrared camera, EPA disagrees with the commenter's interpretation about the extent of equipment subject to leak detection. See preamble Section II.F for a complete discussion about the meters. EPA intended to include in the rule. EPA's response to comment EPA-HQ-OAR-2009-0923-1016-11 discusses the costs associated with the meters EPA intended to include in the rule.

Furthermore, EPA disagrees that there is no definition of "connectors" in the rule; please see the definition for connector as discussed in subpart A of The Final Mandatory GHG Reporting Rule (40 CFR part 98).

Comment Number: EPA-HQ-OAR-2009-0923-1206-13
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
EPA has significantly underestimated the burden to industry to obtain the information to calculate the emission estimate for gathering pipelines.

Response: EPA has removed this source from today's final rule. See Section II.F of the preamble for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1206-25
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
EPA's estimated cost impact is at least an order of magnitude low.

GPA has evaluated the economic impact of the proposed Subpart W as compared with the results to the analysis provided by EPA. Our cost analysis is provided in the following Table 1. Gas Processing Plants and Table 2. Booster Stations with Table 3. a summary of assumptions made. This analysis indicates that EPA's cost estimates are one to two orders of magnitude low. For example, our analysis shows that the average cost of compliance for a gas plant for the initial year will be about $2.4 million, as compared to EPA's estimate of $59,000. Similarly, our analysis demonstrates that the average cost of compliance for a booster station for the initial year will be about $298,000, versus EPA's estimate of $12,000 (a basis for a small gas plant since EPA did not provide a cost breakout for a booster station).

It is clear that EPA has failed to recognize the full impact of requiring reporting at all facilities and pipelines in the natural gas gathering and processing sector. Our analysis shows that EPA has significantly understated the cost and burden of Subpart W as they are significantly higher than EPA projected. GPA requests that EPA re-evaluate the costs associated with this rule, and should significantly simplify and streamline reporting requirements for the midstream sector.

Table 1. Gas Processing Plants
COST ESTIMATE - Year 1

EPA's GHG Mandatory Reporting Rule (Proposed Subpart W)

6/10/2010

	DESCRIPTION		QTY.	UNIT PRICE	National Count	TOTAL	Comments
	General						
	Plant shutdown for meter installation		This cost is highly variable and is not included.				
Subpart C	Combustion				NA		
	Assume combustion sources are already required to report under Subpart C			No added costs			
98.233(d)	Acid Gas Removal Vent Stack				219		75% Gas Plants from EPA inventory have amine treaters
	Add meter for outlet flow		1	$ 100,000		$ 21,900,000	Total installed meter cost
	Meter installation	hr	4	$ 100		$ 87,600	Assume inlet gas is metered
	Sample collection and logging	hr	4	$ 100		$ 87,600	
	Quarterly gas samples of outlet gas		4	$ 400		$ 350,400	Assume inlet gas is sampled
98.233(e)	Dehydrators				292		Gas Plants from EPA inventory
	Assume gas plants currently model dehys			No added costs			
	Feed gas sampling	hr	3	$ 100		$ 87,600	
	Feed gas extended analysis		1	$ 1,200		$ 350,400	
98.233(i)	Blowdown Vent Stacks				292		Gas Plants from EPA inventory
	Write procedure and conduct training	hr	2	$ 100		$ 58,400	
	Determine volume between isolation valves	hr	24	$ 100		$ 700,800	
	Retain logs of blowdown events	hr	24	$ 100		$ 700,800	
	Quarterly gas samples		4	$ 400		$ 350,400	
98.233(j)	Storage Tanks						
	Annual tank modeling	hr	1	$ 100	1168	$ 58,400	Assume 4 tanks per plant
	Sampling separator oil composition	hr	3	$ 100		$ 175,200	
	Separator oil composition analysis		1	$ 1,200	584	$ 700,800	Sampling costs based on 2 separators per plant
	Sales oil API gravity analysis		1	$ 100		$ 58,400	
	Install sampling port		1	$ 5,000	584	$ 2,920,000	Ports required to facilitate annual sampling
98.233(n)	Flare Stack						
	Estimate flare volumes, determine representative composition and efficiency	hr	10	$ 100	292	$ 292,000	Assume 1 flare per plant
98.233(o)	Centrifugal Compressor Wet Seal Degassing Vents				771		Compressors from EPA inventory
	Install degassing vent flow meter		1	$ 100,000		$ 77,100,000	
98.236(a)(17)	Install compressor throughput flow meter		1	$ 100,000		$ 77,100,000	Meters required for vent and compressor flow
	Conduct flow measurement and calibration	hr	2	$ 100		$ 154,200	
	Quarterly gas samples		4	$ 400		$ 1,233,600	
	Log operating hours of VRU and compressor	hr	0.25	$ 100		$ 19,275	

Table 1. Gas Processing Plants
COST ESTIMATE - Year 1

EPA's GHG Mandatory Reporting Rule (Proposed Subpart W)

6/10/2010

	DESCRIPTION		QTY.	UNIT PRICE	National Count	TOTAL	Comments
98.233(p)	Reciprocating Compressor Rod Packing Venting				4781		Compressors from EPA inventory
	# cylinders per compressor				2		
	# operating modes requiring measurement				3		
	Measurement contractor	hr	2	$ 250		$ 14,343,000	Assumes high flow sampler instead of meter
	Operator to assist contractor	hr	1	$ 100		$ 2,868,600	
	Quarterly gas samples		4	$ 400	4781	$ 7,649,600	
98.236(a)(18)	Install compressor throughput flow meter		1	$ 100,000	4781	$ 478,100,000	Total installed meter cost
	Conduct flow measurement and calibration	hr	1	$ 100		$ 478,100	Meter required for compressor throughput
98.233(q)	Fugitive Testing Program				292		Gas Plants from EPA inventory
	Prepare accurate PIDs	hr	8	$ 100		$ 233,600	Assume compositions are available
	Run FLIR Camera - 2 weeks/year	hr	80	$ 120		$ 2,803,200	Assume FLIR equipment is available
	Apply leaker emission factors	hr	5	$ 100		$ 146,000	
	3rd party data storage of FLIR video		1	$ 100		$ 29,200	
	Data Management						
	Data management system configuration		1	$ 10,000	292	$ 2,920,000	Assume existing system modifications
	Data extraction from existing databases	hr	24	$ 100	292	$ 700,800	
	Acid gas removal vent stack	hr	0.1	$ 100	35	$ 350	
	Dehydrators	hr	0.1	$ 100	292	$ 2,920	
	Blowdown vent stacks	hr	0.1	$ 100	292	$ 2,920	
	Storage tanks	hr	0.1	$ 100	584	$ 5,840	
	Flare stacks	hr	0.1	$ 100	292	$ 2,920	Assume one flare per plant
	Centrifugal compressor wet seal degassing	hr	0.1	$ 100	771	$ 7,710	
	Reciprocating compressor rod packing	hr	0.25	$ 100	28686	$ 717,150	
	Fugitive testing	hr	8	$ 100	292	$ 233,600	
	Reporting and Compliance Management						
	Training	hr	8	$ 120	292	$ 280,320	
	Monitoring Plan Development/Revisions	hr	24	$ 120	292	$ 840,960	
98.234	Data QA/QC	hr	16	$ 120	292	$ 560,640	
98.235	Missing data requirements	hr	4	$ 100	292	$ 116,800	
98.236	Reporting	hr	12	$ 120	292	$ 420,480	
98.237	Records retention	hr	8	$ 100	292	$ 233,600	
						$ 698,200,000	

Alternative Average cost per gas plant $ 2,391,096
(based on alternative cost divided by 292 gas plants)
EPA average cost per gas plant (large) $ 58,966

% difference between EPA and GPA costs 3955%

Table 2. Booster Stations
COST ESTIMATE - Year 1

EPA's GHG Mandatory Reporting Rule (Proposed Subpart W)
32,233 Compressors nationally from EPA inventory
6/10/2010

	DESCRIPTION		QTY.	UNIT PRICE	National Count	TOTAL	Comments
	General				12,893		Assume 2.5 compressors per booster station
	Station shutdown for meter installation			This cost is highly variable and is not included.			Compressor count is from EPA inventory
Subpart C	Combustion						One meter per booster station
	Determine fuel consumption through company records (Tier 1 or 2)	hr	1	$ 100	12,893	$ 1,289,320	Assume compressors are not currently reporting Subpart C
	Apply default HHV						Assume no new sampling is required
98.233(d)	Acid Gas Removal Vent Stack				129		Assume 1% of booster stations have AGR
	Add meter for outlet flow		1	$ 100,000		$ 12,893,200	Total installed meter cost
	Meter installation	hr	6	$ 100		$ 77,359	Assume inlet gas is metered
	Sample collection and logging	hr	6	$ 100		$ 77,359	Includes travel time
	Quarterly gas samples of outlet gas		4	$ 400		$ 206,291	Assume inlet gas is sampled
98.233(e)	Dehydrators						Assume 1 dehy per booster
	Assume most dehys are modeled	hr	0.5	$ 100	645	$ 32,233	Assume 5% dehys not modeled
	Gather dehy data	hr	1	$ 100		$ 64,466	
	Feed gas sampling	hr	3	$ 100	12,893	$ 3,867,960	Includes travel time
	Feed gas samples and extended analysis		1	$ 1,200		$ 15,471,840	
	Feed gas water content		1	$ 25		$ 322,330	
	Dry gas water content		1	$ 25		$ 322,330	
98.233(i)	Blowdown Vent Stacks				12,893		
	Write procedure and conduct training	hr	2	$ 100		$ 2,578,640	
	Determine volume between isolation valves	hr	8	$ 100		$ 10,314,560	
	Retain logs of blowdown events	hr	8	$ 100		$ 10,314,560	
	Sample collection and logging	hr	3	$ 100	51,573	$ 15,471,840	Includes travel time for quarterly sampling
	Quarterly gas samples		4	$ 400		$ 20,629,120	
98.233(j)	Storage Tanks						
	Tank modeling	hr	1	$ 100	19,340	$ 1,933,980	Assume 2 tanks per station, 75% require modelin
	Sampling separator oil composition	hr	3	$ 100	12,893	$ 3,867,960	Assume 1 separator per booster station
	Separator oil composition analysis		1	$ 1,200		$ 23,207,760	Sampling includes travel
	Sales oil API gravity analysis		1	$ 100		$ 1,933,980	
	Install sampling port		1	$ 5,000		$ 64,466,000	Ports required to facilitate annual sampling
98.233(n)	Flare Stack						
	Estimate flare volumes, determine representative composition and efficiency	hr	10	$ 100	1,289	$ 1,289,320	10% of stations have a flare
98.233(o)	Centrifugal Compressor Wet Seal Degassing Vents				0		Assume no centrifugal compressors

Table 2. Booster Stations

COST ESTIMATE - Year 1

EPA's GHG Mandatory Reporting Rule (Proposed Subpart W)

32,233 Compressors nationally from EPA inventory

6/10/2010

	DESCRIPTION		QTY.	UNIT PRICE	National Count	TOTAL	Comments
98.233(p)	Reciprocating Compressor Rod Packing Venting				32,233		EPA national inventory gathering compress
	# cylinders per compressor				2		
	# operating modes requiring measurement				3		
	Measurement contractor	hr	4	$ 250		$ 193,398,000	Assumes high flow sampler instead of meter
	Operator to assist contractor	hr	3	$ 100		$ 58,019,400	Labor includes travel time
	Quarterly gas samples		4	$ 400		$ 51,572,800	
98.236(a)(18)	Install compressor throughput flow meter		1	$ 100,000		$ 3,223,300,000	Total installed meter cost
	Conduct flow measurement and calibration	hr	1	$ 100		$ 3,223,300	Requires flow through each compressor
98.233(q)	Fugitive Testing Program				12,893		
	Prepare accurate PIDs	hr	2	$ 100		$ 2,578,640	Assume compositions are available
	Contract fugitive emission measurement		1	$ 3,500		$ 45,126,200	Cost is per facility
	Apply leaker factors	hr	2	$ 100		$ 2,578,640	
98.233(r)	Gathering Pipeline Fugitive				12,893		
	Determine gathering line length	hr	1	$ 100		$ 1,289,320	Assume compositions are available Challenge in associating pipe with plant
	Data Management						
	Data management system configuration		1	$ 2,000	12,893	$ 25,786,400	Assume existing system modifications
	Data extraction from existing databases	hr	24	$ 100	12,893	$ 30,943,680	
	Combustion	hr	0.1	$ 100	32,233	$ 322,330	
	Acid gas removal vent stack	hr	0.1	$ 100	129	$ 1,289	
	Dehydrators	hr	0.1	$ 100	645	$ 6,447	
	Blowdown vent stacks	hr	0.1	$ 100	12,893	$ 128,932	
	Storage tanks	hr	0.1	$ 100	19,340	$ 193,398	
	Flare stacks	hr	0.1	$ 100	1289	$ 12,893	
	Reciprocating compressor rod packing	hr	0.25	$ 100	32,233	$ 805,825	
	Fugitive testing	hr	4	$ 100	12,893	$ 5,157,280	
	Gathering pipelines	hr	0.1	$ 100	12,893	$ 128,932	
	Reporting and Compliance Management						
	Training	hr	8	$ 120	1,289	$ 1,237,747	Group 10 booster stations
	Monitoring Plan Development/Revisions	hr	24	$ 120	1,289	$ 3,713,242	
98.234	Data QA/QC	hr	16	$ 120	1,289	$ 2,475,494	
98.235	Missing data requirements	hr	4	$ 100	1,289	$ 515,728	
98.236	Reporting	hr	12	$ 120	1,289	$ 1,856,621	
98.237	Records retention	hr	8	$ 100	1,289	$ 1,031,456	
						$3,846,000,000	

Alternative Average cost per gas plant (based on alternative cost divided by 12,893 booster stations)	$	298,297
EPA average cost per gas plant (small)	$	12,019
% difference between EPA and GPA costs		2382%

Table 3. EPA's GHG Mandatory Reporting Rule (Proposed Subpart W) Gas Processing Plant and Booster Station Cost Assumptions

Table 1. Gas Processing Plants

General
- Costs associated with shutting down a gas plant to install meters are highly variable
- These costs are not included in the alternative estimate, but would be substantial
- Spreadsheet estimates Year 1 costs

Combustion
- All engines at gas plants already report under Subpart C. No additional costs

Acid Gas Vents
- Outlet gas requires meter and sampling (assume inlet gas is already metered and sampled)
- 75% of gas processing plants have an AGA unit
- EPA's cost estimate of $1400 for a flow meter is an order of magnitude too low
- GPA estimates the total installed cost for a flow meter is $100,000
- Costs for quarterly gas analysis are included for Subpart W compliance
  - Costs include gas analysis, quality check, labor, and disposal fee
- This includes a meter that can meet the required accuracy requirements of the rule,
  - and costs to install piping lengths required for flow measurement
- Costs also account for properties of the gas and tying the meter into the company's
  - data collection system

Dehydrators
- All dehydrators at gas plants are currently modeled
- Feed gas and dry gas water contently are current sampled
- Costs for feed gas extended analysis are included for Subpart W compliance
  - Costs include gas analysis, quality check, labor, and disposal fee

Blowdown vent stacks
- Includes training to ensure consistent determination of equipment volumes

Storage Tanks
- Annual costs for tank modeling are based on 4 tanks per plant and one hour to model each tank
- Sampling costs are based on 2 separators per plant
- Costs for a pressurized hydrocarbon sample, run lab extended analysis and lab report can range
  - from $1,000 to $3,000. An average value of $1,200 is applied for the separator analyses
- Costs include $5000 per separator to install sampling ports to facilitate annual pressurized samples

Flares
- Assume one flare per gas plant
- Labor includes time to determine flare gas rate, representative gas sample, and flare efficiency

Centrifugal compressor wet seal degassing
- 98.236(a)(17) requires reporting compressor throughput
- EPA's estimate of meter cost is an order of magnitude too low
- GPA estimates the total installed cost for an automated flow meter is $100,000
- This includes a meter that can meet the required accuracy requirements of the rule,
  - and costs to install piping lengths required for flow measurement
- Costs for quarterly gas analysis are included for Subpart W compliance
  - Costs include gas analysis, quality check, labor, and disposal fee

Table 3. EPA's GHG Mandatory Reporting Rule (Proposed Subpart W) Gas Processing Plant and Booster Station Cost Assumptions

Reciprocating compressor rod packing
- 98.236(a)(18) requires reporting compressor throughput
- EPA's estimate of meter cost is an order of magnitude too low
- GPA estimates the total installed cost for an automated flow meter is $100,000
- This includes a meter that can meet the required accuracy requirements of the rule, and costs to install piping lengths required for flow measurement
- Cost estimate for rod packing assumes vent is measured using bagging or high flow

Fugitives
- Costs assume a contractor is hired to conduct measurements. No purchase of FLIR equipment.
- Costs include third party data storage of FLIR Video
- Costs do not include repairing leaks that are found

Data Management
- Assume data management system exists, requires modifications for Subpart W reporting

Table 2. Booster Stations

General
- Number of Booster Stations based on EPA count of gathering compressors and 2.5 compressors per station
- Costs associated with shutting down a booster station to install meters are highly variable
- These costs are not included in the alternative estimate, but could be substantial
- Spreadsheet estimates Year 1 costs

Combustion
- Assume gathering compressors do not exceed Subpart C threshold
- These compressors are pulled in due to Subpart W
- Assume one meter per booster station
- Assume Tier 1 or 2 methods apply and fuel sampling is not required (defaults apply)

Acid Gas Vents
- 1% of booster stations have acid gas treatment
- Outlet gas requires metering and sampling
- See comments above about meter costs
- Sampling and meter installation labor include travel to and from booster station

Dehydrators
- Only days < 3mmscf/day require modeling for booster stations
- Assume 1 dehy per booster station and 5% not modeled
- Feed gas extended analysis, feed gas water content and dry gas water content require sampling See comments above about gas sampling
- Sampling labor includes travel to and from the booster station

Blowdown vent stacks
- Includes training to ensure consistent determination of equipment volumes
- See comments above about gas sampling
- Sampling labor includes travel to and from the booster station

Table 3. EPA's GHG Mandatory Reporting Rule (Proposed Subpart W)
Gas Processing Plant and Booster Station Cost Assumptions

Storage Tanks
- Costs for tank modeling are based on 2 tanks per booster station and one hour to model each tank
- Sampling costs are based on 1 separators per booster station
- Costs for a pressurized hydrocarbon sample, run lab extended analysis and lab report can range from $1,000 to $3,000. An average value of $1,200 is applied for the separator analyses
- Costs include $5000 per separator to install sampling ports to facilitate annual pressurized samples.

Flares
- 10% of booster stations have flare
- Labor includes time to determine flare gas rate, representative gas sample, and flare efficiency

Centrifugal compressor wet seal degassing
- No centrifugal compressors used for gathering

Reciprocating compressor rod packing
- See comments above about meter requirements and costs
- Labor includes travel to and from the booster station

Fugitive
- Costs assume a contractor is hired to conduct measurements. No purchase of FLIR equipment. Contractor costs include calibration gas, travel time and per diem, camera fee and data storage.
- Gathering pipelines have to be "assigned" to gas plant for reporting
- Costs do not include repairing leaks that are found

Gathering pipeline fugitive emissions
- Rule requires associating gathering pipeline with gas plants. This is challenging.
- 98.233(R)(3) implies that fugitive component emission factors are applied to gathering pipelines
- Costs associated with determining component counts for equipment associated with gathering pipelines are not included.

Reporting and Compliance Management
- Costs based on grouping of 10 booster stations per activity

Response: EPA disagrees that the April 2010 proposed rule's total national cost estimates are one to two orders of magnitude low for gas processing facilities; see below for more details. EPA has decided not to include gathering lines and boosting stations as an emissions source in today's final rule at this time, see Section II.F of the preamble for further details. As the gathering and boosting costs estimated by this commenter account for $3.8 billion, or approximately 85 percent of their total national cost, this clarification explains the majority of the cost disparity between EPA's and the commenter's cost models.

For natural gas processing, this commenter estimates a first year total national cost of $699 million compared with EPA's total national cost estimate for today's final rule of $7.8 million. EPA has reviewed the assumptions embedded within this commenter's cost model, and this commenter made several assumptions that were not consistent with the proposed rule's intent. One was the assumption that EPA required the installation of permanent flow meters for centrifugal and reciprocating compressors vents and compressors throughput, at a cost of $100,000 per meter. This amounts to a total of $632 million. However, as discussed in Section III.B.2 of the preamble to today's final rule, EPA does not require permanent meters for vents, and allows for installation of a port for using a temporary insertion flow meter for an annual estimate of a one-time measurement of vented emissions from specified compressor vent emissions. In addition, EPA is allowing in today's final rule the use of an acoustic detection device (non-invasive) for detecting and quantifying through valve leakage for some of the compressor emissions: closed blowdown vent valve leakage and closed compressor unit isolation valve leakage through a depressurized compressor. EPA did not intend for reporters to install a meter to determine compressor throughput. EPA has clarified this in today's final rule and allows reporters to use engineering estimation to determine compressor throughput; see Section II.F of the preamble for further details. EPA requires the compressor throughput for analysis of the activity data and the resultant GHG emissions reports, as combustion CO_2 will be proportional to compressor throughput. Finally, the commenter assumed that the rule would cover all compressors in natural gas processing, or about 5,552 compressors, which exceeds EPA's estimated coverage of about 3,796 compressors at the 25,000 metric ton CO_2e reporting threshold. See Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923) for EPA's detailed threshold analysis. These factors explain the large disparity between the EPA and the commenter's compliance cost, and account for a difference in national cost of $627 million.

The commenter has also assumed for the natural gas processing segment the installation of permanent flow meters to measure the acid gas removal vent stacks at a cost of $100,000 per meter for a total national cost of $21.9 million. Please see preamble III.B.2 for EPA's response.

The commenter also assumed that in natural gas processing, quarterly gas sampling was required for each compressor, dehydrator, and AGR unit for a total national cost of $9.8 million. As explained in the Section II.F preamble of today's final rule, EPA modified the requirements by replacing quarterly sampling of gas composition with the option of best available sample analysis for compressors and dehydrator vents. AGR units require quarterly sampling, if CEMS is not available or is not installed, or if a continuous gas analyzer is available or not installed. This accounts for a difference in national cost of $7.3 million.

The commenter has assumed that to model emissions from storage tanks in the natural gas processing segment, there would be costs associated with computer modeling, sampling and analysis, and the installation of sampling ports for a total national cost of $3.9 million. EPA has determined that natural gas processing facility storage tanks are not a significant emission source. EPA has determined that most gas condensate coming into a processing facility will have passed through a field or gathering atmospheric pressure storage tank and have been stabilized (i.e. water has been removed and flash vapors have been released from the gas condensate). Hence, the emissions from processing storage tanks are expected to be minimal. . Therefore, in the today's final rule, EPA has provided a clarification by excluding the requirement for monitoring natural gas processing storage tanks.

The commenter has assumed for natural gas processing data management system and reporting and compliance management a total national cost of $7.0 million. Although the commenter did not provide any information about the software represented in its analysis (except for cost), EPA disagrees with the commenter's cost estimate as even the largest of reporters under this final action will be able to use or adapt from their data management and reporting obligations under subpart C the standard spreadsheets or databases to collect the emissions data and perform calculations at a facility level. EPA accounted for data management costs by factoring in estimates of labor to set up spreadsheets and other archiving and recordkeeping activities, as well as equipment costs like file cabinets and external hard drives; see the EIA for a complete discussion. EPA estimated the costs for data management and reporting under subpart W alone to be $1.5 million in today's final rule. This accounts for a difference in national cost of $5.5 million.

Comment Number: EPA-HQ-OAR-2009-0923-1206-48
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
Third, EPA has greatly underestimated the cost and effort to conduct the direct measurement prescribed for these sources. Any one company will have hundreds or thousand of compressors in operation, each one with multiple compressor rod packings. Additional complexity and cost are presented in the many cases when a single compressor is used for multiple services, for example inlet compression, residue compression and refrigeration compression.

Response: EPA disagrees that the proposed rule underestimated costs. This commenter assumed that the rule would cover all compressors in natural gas processing, or about 5,552 compressors (see EPA-HQ-OAR-2009-0923-1206-25 for commenter's detailed analysis). The commenter's estimate exceeds EPA's estimated coverage of about 3,796 compressors; please see EPA's response to comment number EPA-HQ-OAR-2009-0923-1206-25.

Comment Number: EPA-HQ-OAR-2009-0923-1206-50
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
On a related issue, Section 98.236(c)(18) requires reporting the gas throughput for each compressor. The metering required for this reporting is not typically in place today and would require installation of meters on each compressor at a cost of about $100,000 per meter. If a company has 1000 compressors, the capital cost to collect this one piece of operational data is $100 million for data this is not even necessary for calculating emissions from a compressor rod packing.

Response: EPA disagrees with this comment, as the rule does not require the installation of $100,000 permanent flow meters; see EPA's response to EPA-HQ-OAR-2009-0923-1206-25.

Comment Number: EPA-HQ-OAR-2009-0923-1299-18
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:
This proposed rule will however add major costs against uncertain gains, given the uncertainty of the methodology applied. Estimated compliance costs for natural gas utilities within these regulatory parameters are high and raise serious concerns. The ability of a utility company to recover these costs in a rate case is uncertain, particularly in a time of difficult economic circumstances for most homeowners, businesses and average ratepayers. We would urge EPA to consider the issue of compliance costs very carefully.

Response: EPA disagrees that the proposed rule's compliance costs were underestimated. For EPA's response to comments that it underestimated costs for the distribution segment, see comment EPA-HQ-OAR-2009-0923-1152-4. EPA has determined that the burden to LDCs is minimal and did not incorporate any assumptions in the analysis about passing costs on to consumers in the form of higher rates. However, even if reporters pass on the cost to their customers the effect on product prices will be insignificant. Please see EPA-HQ-OAR-2009-0923-1303-2, for EPA's response to the comment regarding compliance costs and the passing on of these costs to consumers.

EPA has thoroughly reviewed and updated its cost estimates to reflect changes in today's final rule (e.g. incorporating the capital cost to purchase a laser emissions detector versus an optical imaging device). See Section II.E and II. F of the preamble for major changes to the rule and Section III of the preamble for a summary of this analysis and the Economic Impact Analysis for a detailed discussion on costs.

Comment Number: EPA-HQ-OAR-2009-0923-1306-11
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
The costs to implement Subpart W for LDCs have been grossly underestimated by EPA and are not indicative of a reasonable cost to measure the small amount of GHGs emitted from natural gas LDCs.

EPA has estimated that the total industry-wide annual cost of complying with Subpart W for natural gas distribution will be $1.6 million in the first year and $1 million per year thereafter.[121] EPA estimates that 143 LDCs will be subject to Subpart W using a facility threshold of 25,000 tons per year CO2e.[122] Accordingly, EPA is estimating a per company cost of $11,188 in the first year and about $7,000 per year per LDC thereafter. These costs are grossly underestimated for the anticipated level of work that would be required to be performed on the MichCon distribution system for DTE Energy to comply with Subpart W.

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[121] 75 Fed. Reg. at 18625, Tables W-5 and W-6.

[122] EPA, Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions Under Subpart W Supplemental Rule (GHG Reporting), Final Report (Dec. 8, 2009) (Economic Analysis) at page 4-5.

DTE Energy (MichCon) owns and operates 467 city gates/custody transfer stations, approximately 600 above grade district regulators, and approximately 1,700 below grade district regulators. DTE Energy also employs a significant number of “farm taps” and industrial meter and regulator (M&R) stations which serve to lower the natural gas pressure to the level required to provide gas to the end user. As currently written, DTE Energy believes that the proposed rule would require all 467 city gates/custody transfer stations, 600 above grade district regulators, all farm taps, and potentially all the industrial M&R stations to perform leak detection by optical imaging equipment. These metering and regulating stations are located throughout the state of Michigan, including the Upper Peninsula.

Assuming that DTE Energy utilizes its own internal resources for conducting the required monitoring of the MichCon LDC, we anticipate the first year costs to exceed $100,000 alone for purchase of optical imaging equipment and training of personnel on the equipment. Furthermore, we estimate that we will need at least two full time equivalent (FTE) employees to conduct the required annual leak detection monitoring for the MichCon distribution system. This estimated level of effort includes the time to conduct leak tests at more than 1,000 locations, driving time, and data management activities required to inventory, record, and update leak records from thousands of components. The level of effort to comply with the rule for LDCs has been grossly underestimated by EPA and is not appropriate for measuring GHG emissions that account for less than 1% of total U.S. GHG emissions.

Response: EPA disagrees that the proposed rule’s costs were grossly underestimated. First, the requirements do not apply to customer meters (industrial, commercial, and residential meters) or to farm taps. See preamble Section II.F for a complete discussion about the meters EPA intended to include in the rule. EPA’s response to comment EPA-HQ-OAR-2009-0923-1016-11 discusses the costs associated with the meters EPA intended to include in the rule.

Similar to the commenter’s analysis, EPA assumed reporters would need to visit M&R stations, but unlike the commenter, did not estimate costs for visits to customer meters because they are not subject to the rule. Please see EPA-HQ-OAR-2009-0923-1016-11 for further details on EPA’s assumptions about component count requirements and discussion about sources covered under the rule.

EPA is unable to evaluate the commenter’s estimate of $100,000 for optical leak detection equipment and training because insufficient documentation was provided to explain how this figure was calculated. For example, the commenter did not specify their assumptions about the number of cameras required to monitor their sources, the cost of a camera, nor the duration and cost of training assumed. Also, EPA has annualized all costs over the life of the equipment (5 years in the case of an optical camera) and at a discount rate of 7 percent per annum. Finally, EPA has revised today’s final rule to allow alternative options for leak detection. See preamble Section II.F for details about the alternative leak detection options, such as the use of Method 21 to conduct leak detection surveys. This new option may potentially offer a less costly alternative for the commenter. See EPA’s response to EPA-HQ-OAR-2009-0923-1020-6 for details about EPA’s assumptions for the costs associated with optical leak detection equipment.

Furthermore, the commenter did not explain why at least two full time equivalent employees would be required to comply with the rule. See EPA-HQ-OAR-2009-0923-1016-11 for EPA's response to concerns about the costs for leak detection; see preamble Section II.F for details about permitted alternative leak detection options.

Comment Number: EPA-HQ-OAR-2009-0923-1306-5
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
Local Distribution Companies (LDCs) Should Not be Required to Report Under the Mandatory Greenhouse Gas Reporting Rule

According to EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, emissions of methane (CH_4) and non-combustion CO_2 from natural gas distribution systems account for less than 1% of U.S. total CO_2e emissions. The level of effort to measure natural gas local distribution company (LDC) emissions that is proposed in the rule is not commensurate with the magnitude of the expected emissions from natural gas LDCs. This level of effort translates into significant added resource costs for monitoring equipment (e.g. leak detection instrumentation), data-base management, training, and the cost of technicians to visit, inspect, log, and report fugitive emissions from components on a natural gas distribution system.

Response: As described in EPA's response to EPA-HQ-OAR-2009-0923-0837-9, EPA disagrees that it underestimated the compliance costs. Regarding the commenter's concerns about how the level of effort to monitor emissions compares to the value of the data, see EPA's response to EPA-HQ-OAR-2009-0923-1014-5.

Comment Number: EPA-HQ-OAR-2009-0923-1306-7
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
The costs to implement Subpart W for LDCs have been grossly underestimated by EPA and are not indicative of a reasonable cost to measure the small amount of GHGs emitted from natural gas LDCs The proposed rule requires significant additional effort to log and report leaks beyond current requirements for detecting and fixing leaks on distribution systems, and does not recognize that existing programs already minimize fugitive emissions from LDCs

Response: As described in the response to comment EPA-HQ-OAR-2009-0923-1152-4 above, EPA disagrees that the proposed rule's compliance costs were underestimated. For response to the commenter's concerns about how current leak detection practices relate to today's final rule, see comment EPA-HQ-OAR-2009-0923-1156-14.

10.4 ECONOMIC IMPACTS

Comment Number: EPA-HQ-OAR-2009-0923-1151-15
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Executive Order 12866

Finally, EPA neglected to include the full economic impacts of proposed Subpart W in the analysis required by EO 12866. EO 12866 directs EPA to submit to OMB new significant regulations under consideration by the Agency.[123] EPA states that it submitted proposed Subpart W to OMB for review under Executive Order 12866. However, the Agency failed to include anything close to the full costs of the rule in the Economic Impact Analysis and there is no indication that EPA included these costs in its submission to OMB. Without this key information, OMB could not fully review the impacts of the proposed rulemaking.

Response: EPA disagrees with this comment. As stated in the preamble Section IV and in the Economic Impact Analysis, EPA determined that this rulemaking is a "significant regulatory action" pursuant to Executive Order 12866 because it raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in EO 12866. Accordingly, EPA submitted the Economic Impact Analysis to the Office of Management and Budget (OMB) for review under Executive Order 12866 as part of the proposed and final rulemakings, thereby meeting all the requirements of this Executive Order.
EPA relied on best available data and methods to estimate the costs and economic impacts of the rulemaking and documented the analysis and results in the Economic Impact Analysis, thereby facilitating a complete OMB review. As discussed in the preamble Section III, EPA collected and evaluated cost data from multiple sources, thoroughly reviewed the input received through public comments, and weighed the analysis prepared for the proposal against this input. In finalizing the rule, EPA has determined that the Economic Impact Analysis provides a reasonable characterization of costs and that the documentation provides adequate explanation of how the costs were estimated.

For detailed responses to the cost and economic comments from this commenter, see EPA-HQ-OAR-2009-0923-1151-89 through EPA-HQ-OAR-2009-0923-1151-107 for further details. EPA-HQ-OAR-2009-0923-1151-107 identifies source categories discussed in each comment.

Comment Number: EPA-HQ-OAR-2009-0923-1196-7
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

Comment Excerpt Text:
If the required sources to report are aggregated by basin, the increased number of facilities requiring travel to remote areas has not been taken into consideration. The EPA's cost estimations also assume that staff exists on-site to assist with GHG reporting implementation: the

[123] Executive Order 12866 Section 6(a).

opposite is true. Many operators will be forced to hire additional temporary staff or utilize consultants to review and compile data from various divisions in order to determine if a company is in compliance with the proposed rule. Discussions with state regulators on this very point has demonstrated that a new cottage industry of greenhouse emissions auditors will need to be found and adequately trained to assist the hundreds of small businesses in need of reporting data. In the preamble to this rule, EPA notes that it completely changed the required methodologies and now requires more reporting from smaller sources that have limited or no emissions data. Direct measurement is required for transmission tanks, wet seal degassing, reciprocating rod packing venting, flare stacks. Requiring direct measurement of transmission tanks, wet seal degassing and reciprocating rod packing venting will require field personnel to visit each site to determine which sources must be reported, and to measure each of those sources. The direct measurement of the small sources is costly, time consuming and will require significant use of consulting sources to achieve compliance with the proposed rule.

Response: EPA disagrees that operators will need to hire additional temporary staff or use consultants to determine whether or not they have to comply with Subpart W; EPA also disagrees with the commenter's assumptions about travel costs. Please see EPA's response to EPA-HQ-OAR-2009-1060-1 and EPA-HQ-OAR-2009-0923-1151-89 for the complete response. Furthermore, EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. Accordingly, EPA has updated the Economic Impact Analysis to better account for reporting determinations and expected use of screening tools; see EPA's complete response in Section III.B.2 of the preamble to today's final rule.

This commenter also expressed concerns about the impact of the rule on small businesses. See EPA-HQ-OAR-2009-0923-1005-7 for EPA's response, which includes a discussion about the analysis supporting EPA's conclusion that the rule will not have a significant economic impact on a substantial number of small entities.

EPA agrees with the comment that the direct measurement of emissions from compressors and storage tanks in the onshore production sector is overly burdensome for the emissions covered. Please refer to Section II.E of the preamble (EPA-HQ-OAR-2009-0923) for changes EPA has made to the Rule with respect to storage tanks and reciprocating compressors.

However, EPA determined the direct measurement of emissions from condensate storage tanks, compressors, and flare stacks in natural gas transmission sector is necessary in order to obtain data of sufficient quality to inform policy. Please see the response to comment EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for complete discussion about why EPA selected direct measurement for these sources.

Comment Number: EPA-HQ-OAR-2009-0923-1303-2
Organization: Texas Department of Agriculture
Commenter: Todd Staples

Comment Excerpt Text:
Placing additional regulatory and reporting burdens on this industry will certainly increase the

cost of both agricultural production and consumer consumption of food and fiber.

Inelasticity and susceptibility to price volatility are defining characteristics of the agricultural marketplace. As the industries providing the basic inputs agriculture relies on (fertilizers, chemicals and fuels in this case), see increased costs due to the burden of greenhouse gas emission reporting, so will agriculture producers, and therefore all American consumers. According to the USDA, 13 percent of agricultural producers' costs of production result from these input costs. Unlike many other industries, however, agriculture has few options in curbing its demand for these inputs and only one option for passing along cost increases to third parties-to reduce supply.

Likewise, consumers are unable to curb demand for our basic life necessities-food and fiber. The resulting impact of this economic squeeze will likely be reduced food and fiber supply and increased consumer prices.

Response: EPA does not agree with the comment. EPA would like to reiterate that today's final rule collects information related to GHG emissions from the petroleum and natural gas industry to inform future policy; the rule does not regulate GHG emissions. See EPA-HQ-OAR-2009-0923-1010-2 for EPA's response to comments about its efforts to reduce the burden and costs of the rule, while still ensuring that the program yields high quality data and essential information.

Also, EPA disagrees with the commenter's conclusion that today's final rule will increase the price of fuels. Although the commenter did not provide documentation or information to substantiate the conclusions, EPA has nonetheless conducted an analysis to consider the potential impact of price increases. EPA determined that even if reporters were to pass all costs associated with today's final rule to consumers in the form of higher petroleum and natural gas prices, the marginal price change would be minimal. In sum, EPA estimates that this price increase would be less than one cent per barrel of oil or thousand cubic feet of gas, which is about 0.1 percent of 2006 oil and gas prices. (Please refer to the "Subpart W Greater Economic Impact" docket memo EPA-HQ-OAR-2009-0923). EPA considers that such a small burden is justified to collect necessary information that will help formulate cost-effective policies in the future. This analysis remains consistent with EPA's conclusion that the potential benefits of more comprehensive information about GHG emissions outweigh the costs of today's final rule.

10.5 IMPACTS FOR SMALL ENTITIES

Comment Number: EPA-HQ-OAR-2009-0923-0053-1
Organization: Cardinal Engineering, Inc.
Commenter: Kristine D. Baranski

Comment Excerpt Text:

The commenter is concerned about the expense of reporting for production. Basin level reporting would likely require reporting from small or marginal wells that might otherwise fall below a field or well level threshold. There are numerous marginal wells in existence, and this will have a large economic consequence to the profitability of each well. The environmental cost is additive to the well development cost, which may result in plugged and abandoned wells.

Response: EPA recognizes the commenter's concerns about costs associated with today's final rule and has made every effort to reduce the burden and costs of the rule, while still ensuring that the program yields high quality data and essential information. As discussed in Section II of the preamble, today's final rule includes alternative data collection methodologies to target major emitting equipment sources. While today's final rule will require reporting from some marginal wells, EPA has determined that the associated burden will be minimal. First, today's final rule requires reporters to inventory only major equipment to estimate emissions, not every well nor all equipment at a well. Please see response to EPA-HQ-OAR-2009-0923-1151-5 for discussion about changes EPA made to today's final rule to reduce burden for onshore production, such as requiring operators to count their major equipment instead of each individual component. Reporters will not need inventory most marginal wells because these wells typically do not have major equipment due to the small volumes of production. In other cases, multiple marginal wells will be connected to the same equipment; an operator would count the equipment but would not need to do an inventory at the attached marginal wells. Second, today's final rule has several equipment thresholds that in most cases result in insignificant burden on marginal wells; EPA expects most marginal wells to fall below the equipment threshold, thereby allowing the reporter to use an emissions factor based approach. See also EPA-HQ-OAR-2009-0923-1005-7, which summarizes EPA's analysis of today's final rule's economic impact on small entities and the basis for EPA's conclusion that today's final rule does not target marginal operators who own few wells and have small volumes of production.

While EPA notes that basin-level reporting may require reporting from some marginal wells, EPA has concluded that basin-level reporting will more directly and completely meet EPA's objective to collect accurate and comprehensive data on emissions across the petroleum and natural gas sector to better inform future public policy. In particular, EPA analyzed emissions coverage at different thresholds for the field- and basin-level options and found that basin-level reporting is the more cost-effective option. See the Chapter 5 of the Economic Impact Analysis for discussion of the analysis and results (EPA-HQ-OAR-2009-0923).
EPA agrees that the compliance costs—i.e., the "environmental cost" noted by the commenter—will be additive to well development cost. EPA has therefore selected the most cost effective reporting threshold and facility definition. Please see Section II.C of the preamble to the April 2010 proposal (EPA-HQ-OAR-2009-0923) for more details on the rationale for choosing basin-level reporting over field- and well-level reporting.

Comment Number: EPA-HQ-OAR-2009-0923-1005-7
Organization: Independent Petroleum Association of America
Commenter: Lee Fuller

Comment Excerpt Text:

Small Business Implications

EPA cavalierly asserts that this proposal "…will not have a significant economic impact on a substantial number of small entities." But, can this be true? Comparing numbers of wells that must report against the number of wells operated by small businesses shows a different result.

In creating its basin-level reporting approach, EPA indicates that it will capture 81 percent of the onshore petroleum and natural gas production GHG emissions. It also states – in rejecting the logical well pad facility definition – that individual well pad emissions were low. Consequently, we must conclude that EPA's definition must capture something close to 80 percent of the operating wells.

In 2008, there were 960,303 operating wells in the U.S. (525,287 oil wells and 435,016 natural gas wells, with about 7,000 of these in the federal offshore). The Energy Information Administration reports that 85 percent of these oil wells and 73.3 percent of these natural gas wells are marginal wells. Assuming a proportional distribution across wells, the following results would be produced:

	Wells Reported Under Rule	Marginal Wells Reported Under Rule
Oil Wells	417,300	354,815
Natural Gas Wells	345,213	253,041
Total	762,513	607,856

Clearly, there will be a pervasive burden borne by America's marginal well producers. EPA is well aware that the companies operating marginal wells are dominated by small businesses. To suggest that the proposed rule will not have a significant impact on small businesses is simply incorrect.

Response: EPA analyzed the economic impact of today's final rule on small entities in accordance with the Regulatory Flexibility Act and the Small Business Regulatory Enforcement and Fairness Act. This analysis revealed that the average ratio of annualized reporting program costs to receipts of establishments owned by model small enterprises was less than 1 percent for industries presumed likely to have small businesses covered by the reporting program, except for entities in onshore production with 1-20 employees, for which the ratio was between 1 and 2 percent. Although a majority of the enterprises in the petroleum and natural gas industry fall in the 1-20 employee range, most of the production, and therefore emissions, comes from large corporations. In fact, the top 20 large corporations in the U.S. account for 85 percent of the total oil and 77 percent of the total gas produced in the country. Small enterprises have very small operations (such as a single family owning a few production wells) that are highly unlikely to cross the 25,000 metric tons CO_2e reporting threshold.

In addition, EPA disagrees with the commenter's analysis of the number of wells subject to reporting; the percentage of GHG emissions covered under the rule does not equal the percentage of wells subject to reporting. Please see EPA's response to EPA-HQ-OAR-2009-0923-1151-89 for a discussion regarding the number of affected wells and the associated costs.

Furthermore, the operation of marginal wells is not limited to marginal operators; large operators own marginal wells. EPA's threshold analysis shows that today's final rule does not target marginal operators who own few wells and have small volumes of production. Using the HPDI database, EPA estimated that of the 19,876 marginal operators in the United States, only 2 percent (or 349 marginal operators) would meet the reporting threshold. (Marginal operators are facilities with an average petroleum production below 10 barrels per day per well and an average natural gas production below 75 thousand cubic feet per day per well.) Most marginal reporters do not typically operate equipment that exceeds the equipment thresholds for separators and dehydrators. In addition, any compressors at the marginal wellhead will use population emissions factors. Therefore, marginal operators that meet the reporting threshold would likely be able to report emissions primarily using population factors. See EPA-HQ-OAR-2009-0923-0053-1 for further discussion about final rule revisions that minimize burden associated with reporting from marginal wells.

Based on this analysis, EPA concluded that this action will not have a significant economic impact on a substantial number of small entities. The summary of the factual basis for the certification is provided in Section IV of the preamble for the rule. Complete documentation of the analysis can be found in the final Economic Impact Analysis (EIA), Section 5.2 (EPA-HQ-OAR-2009-0923). For further response to comments on owners of marginal wells, please see EPA-HQ-OAR-2009-0923-0053-1.

Finally, EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. In particular, the screening tools will assist marginal operators and other entities in determining whether or not they meet the threshold. See EPA's complete response in Section III.B.2 of the preamble to today's final rule.
In sum, this analysis is consistent with EPA's conclusion that today's final rule will not have a significant economic impact on a substantial number of marginal U.S. operators. Please see EPA's response to EPA-HQ-OAR-2009-0923-0053 -1 for further discussion about Subpart W's effect on marginal wells.

Comment Number: EPA-HQ-OAR-2009-0923-1010-2
Organization: Oklahoma Independent Petroleum Association
Commenter: Burckhalter

Comment Excerpt Text:
Impacts to small crude oil and natural gas businesses will be significant. Many oil and gas operators in Oklahoma are small businesses (similar to small family farms). These small independent oil and gas companies are ill-equipped to bear the costly burdens of GHG reporting requirements. The risk tolerance of these small independent producers is significantly different, and significantly less, as compared to large, integrated oil companies. In addition, most of these smaller oil and gas businesses operate marginal wells. Marginal wells are mature crude oil and natural gas producing properties that have lost their initial, high production rates and instead operate on the much lower, flat end of the natural production decline curve. Each well has its own unique economic hurdles that dictate whether the well is produced or not. The draft rule will require oil and gas companies to conduct very detailed inventories of all equipment that could emit GHGs even down to counting all threaded connections! These inventories would then be

required to be evaluated in detail to determine their leak potential and only then could the operator calculate the CO_2e emission rate. It is clear that small operators would have to hire consultants to do this work for them which would undoubtedly force many wells to be plugged due to their then uneconomic status. Our country will lose the much needed domestically produced energy and will lead to many small businesses failing.

The Interstate Oil and Gas Compact Commission define marginal wells as those that produce 10 barrels of oil per day or less, and less than 60 thousand cubic feet per day. In Oklahoma, marginal wells produce on the average 1.7 barrels of oil per day and 24.3 thousand cubic feet of gas per day. The emissions from these types of facilities are low, so low they are not required to have an air emission permit. Despite the low production rates and pressures of marginal wells, approximately 19 percent of the U.S. oil production and 8 percent of the natural gas produced in the lower 48 states comes from marginal wells. EPA must carefully analyze the impacts to marginal wells and ensure that any increased regulatory costs are clearly justified, especially in these difficult economic times.

We believe that EPA has underestimated the number of operators and wells impacted and the cost impacts on small crude oil and natural gas operators of marginal wells located in our state and around the country. We believe this is fundamentally inconsistent with efforts to protect and enhance national security by increasing domestic energy production and reducing dependency of foreign oil. We do not believe EPA has fully addressed Executive Order 13211, and request EPA reanalyze this issue.

Response: EPA understands the commenter's concerns and has made every effort to reduce the burden and costs of the rule, while still ensuring that the program yields high quality data and essential information. EPA also recognizes the importance of considering the rule's impacts on small entities and has analyzed the potential for such impacts; see EPA-HQ-OAR-2009-0923-1005-7, which summarizes EPA's analysis of today's final rule's economic impact on small entities and the basis for EPA's conclusion that today's final rule does not target marginal operators who own few wells and have small volumes of production. Furthermore, while today's final rule will require reporting from some marginal wells, the associated burden will be minimal. See EPA-HQ-OAR-2009-0923-0053-1 for further discussion about final rule revisions that minimize burden associated with reporting from marginal wells.

EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. In particular, the screening tools will assist small entities in determining whether or not they meet the threshold. EPA expects the screening tools will assist most small entities in their threshold determination.

Overall, this analysis is consistent with EPA's conclusion that today's final rule will not have a significant economic impact on a substantial number of marginal U.S. operators.
EPA disagrees that it did not fully address EO 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use," (66 FR 28355 (May 22, 2001)). This EO requires federal agencies undertaking certain regulatory actions to prepare a "Statement of Energy Effects" that describes the adverse effects of a "significant energy action" on energy supply, distribution and use, reasonable alternatives to the action, and the expected effects of the

alternatives on energy supply, distribution and use. EO 13211 applies only to regulatory actions leading to “significant adverse energy effects.” A significant adverse energy effect would occur under this action if today’s final rule were to increase the costs of energy production or cost of energy distribution by one percent.

EPA’s analysis, “Subpart W Greater Economic Impact,” (EPA-HQ-OAR-2009-0923), demonstrates that the rule will not have a significant, adverse impact on the supply (productivity), competition, or prices in the energy sector. Specifically, the analysis revealed that that even if all of the costs associated with complying with today’s final rule were passed on to consumers in the form of higher petroleum and natural gas prices, the marginal price change would be minimal. EPA estimates that the price increase would be less than 0.1 percent increase in natural gas price and a 0.01 percent increase in crude oil price. This is significantly lower than the one percent increase in fuel price (assuming a price of $7.70 per Mcf of natural gas[124] and $58.15 per Barrel of oil[125]) criterion as it applies to EO 13211. Given that the impact of the rule on fuel prices is minimal, EPA does not expect the rule to affect demand for fuels. Therefore, the rule will not affect current and future production from operators who build production capacity based on perceived demand. In addition, the rule does not require the operators to shut down either parts or entire operations for monitoring emissions sources that could lead to supply disruption.

In sum, EPA concluded that this rule would not have a significant, adverse impact on the supply (productivity), competition, or prices in the energy sector. As a result, EPA has determined that EO 13211 does not apply to today’s rule because it does not have any significant adverse impact on energy supply, distribution, or use.

Comment Number: EPA-HQ-OAR-2009-0923-1010-4
Organization: Oklahoma Independent Petroleum Association
Commenter: Burckhalter

Comment Excerpt Text:
Basin level reporting is not appropriate for onshore crude oil and natural gas production sites. EPA proposes that emissions from onshore crude oil and natural gas production sites be reported at the basin level. As previously stated, defining a "facility" to include many wells over a very large area is contrary to the Clean Air Act definition, and will subject many small businesses to the proposed GHG data collection and reporting requirements that is directly opposite of EPA's stated goal to limit the impacts to small businesses. We believe the proposed reporting rule will be unreasonably burdensome and costly. Operators hiring consultants will incur numerous mobilization fees as the consultants go from site to site across a basin. This will no doubt negatively impact most wells, especially marginal wells, such that many may become uneconomic to produce. In addition, EPA requests comments on reducing the reporting threshold

[124] EIA. (2008) *Annual Energy Review.* Table 6.7. Retrieved on July 28, 2010 at http://www.eia.doe.gov/emeu/aer/pdf/pages/sec6_17.pdf. A 5-year average from 2003 to 2008.

[125] EIA. (2008) *Annual Energy Review.* Table 5.18. Retrieved on July 28, 2010 at http://www.eia.doe.gov/emeu/aer/pdf/pages/sec5_45.pdf. A 5-year average from 2003 to 2008.

from 25,000 $mtCO_2e$ to 10,000 $mtCO_2e$ for onshore petroleum and natural gas production. This would be even more problematic for all operators, but especially for small businesses. EPA has the flexibility in determining who should be subject to the reporting requirements. We request EPA not use a basin level approach that will unnecessarily include many operators of wells (including marginal wells) in the reporting requirements for onshore petroleum and natural gas production industry.

Response: Please see comment EPA-HQ-OAR-2009-0923-1010-1 for a response to the comment on the definition of a "facility". For EPA's response to comments on the rule's impacts on small entities and on operators of marginal wells, see EPA's response to comment EPA-HQ-OAR-2009-0923-1005-7. Please see the response to EPA-HQ-OAR-2009-0923-1151-89 for a discussion regarding the number of affected wells and the subsequent burden. Please see EPA's response to EPA-HQ-OAR-2009-0923-1196-7 for discussion about why EPA disagrees that operators will need to hire contractors to comply with Subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1014-3
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:

Indeed, USEPA acknowledges in the Preamble to its proposal that its novel basin-level aggregation approach was adopted precisely because individual production wells generally will fall below the very threshold that USEPA selected, after careful evaluation and analysis, as representing the most appropriate balance between the amount of GHG emissions to be reported and the burden on small emitters. See 75 Fed. Reg. at 18615. As intended, the basin-level approach will require operators to report emissions from small or marginal wells that emit GHGs in quantities far below 25,000 tpy CO_2e[126] Not surprisingly, the burden associated with the proposed basin-level approach will be considerable, as the costs associated with monitoring and reporting the emissions from these marginal wells will add to the existing development and operational costs, resulting in substantial economic consequences for the profitability of such wells. Indeed, IOGA-WV harbors serious concerns that the significant costs associated with conducting this monitoring---even if only for purposes of determining Subpart W's applicability-will result in the premature capping, plugging and abandonment of these small or marginal wells, despite the fact that they remain viable energy resources that should be a vital part of this country's movement towards "green" energy development. Further, the economic impact of abandoning these wells will extend far beyond the individual well owners to employees and contractors of those companies, their families, affected mineral owners, and the broader local communities, which will lose tax revenues and other benefits associated with the continued operations of these wells-all consequences that should be avoided in the nation's still-struggling economy. Such outcomes directly contradict USEPA's stated goal to "balance the rule coverage to maximize the amount of emissions reported while excluding small emitters. 74 Fed. Reg. 16448, 16456 (April 10,2009).

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[126] IOGA-WV refers USEPA to the statistics set forth in EPA's comments, which represent that approximately 85% of oil wells and 74% of natural gas wells are marginal wells producing less than 15 barrels/day of oil and 90 mcf/day of natural gas, respectively.

Response: For EPA's response to comments on the rule's impacts on small entities and on the operators of marginal wells, see EPA's response to comment EPA-HQ-OAR-2009-0923-1005-7. Please see the response to EPA-HQ-OAR-2009-0923-1151-89 for a discussion regarding the number of affected wells and the subsequent burden. Finally, see the memo on "Subpart W Greater Economic Impact" (EPA-HQ-OAR-2009-0923) for discussion about the Final Greenhouse Gas Reporting Rule's impact on the greater U.S. economy and its citizens.

Comment Number: EPA-HQ-OAR-2009-0923-1029-4
Organization: Western Business Roundtable
Commenter: Holly Propst

Comment Excerpt Text:
EPA's Approach Would Cause Significant Burden on Small, Independent Producers

We are particularly concerned about the potential impact of this rule on onshore oil and gas producers in the West. The vast majority of the onshore facilities that would be forced to report under the rule are marginal wells. Entities operating such marginal wells -- particularly in our region -- are predominately small businesses. The regulatory burden on such enterprises would be significant. EPA seems to inappropriately minimize these impacts in its analysis.

Response: For EPA's response to comments on the rule's impacts on small entities and the burden for operators of marginal wells, see EPA's response to comment EPA-HQ-OAR-2009-0923-1005-7 and EPA-HQ-OAR-2009-0923-0053-1.

Comment Number: EPA-HQ-OAR-2009-0923-1080-49
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
EPA makes the following conclusion in the preamble to the proposed Subpart W.

…[The rule would] requir[e] only a small fraction of total facilities to report. 75 Fed. Reg. at 18619.

The proposed Subpart W in fact increases coverage of gas gathering and processing facilities to nearly 100% regardless of facility size, which is unduly burdensome and neither reasonable nor appropriate.

Response: The statement identified by the commenter described the fraction of entities from all covered segments subject to reporting, not the coverage of entities from a particular segment. Under today's final rule, EPA expects a small fraction of entities in the domestic oil and gas industry to be subject to reporting; see Section 4.4 of the Economic Impact Analysis (EIA)

(EPA-HQ-OAR-2009-0923) for complete details on the number and share of entities and emissions covered. As discussed in the EIA, EPA analyzed various reporting thresholds to identify one that would ensure maximum emissions reporting coverage with minimal burden on the industry

Regarding the commenter's conclusion that 100 percent of entities in the gas gathering and processing segment would be covered, today's final rule does not include gathering lines and boosting stations as an emissions source in subpart W at this time, see comment response EPA-HQ-OAR-2009-0923-1206-13 and Section II.F of the preamble for full details. Of the remaining processing facilities that could be candidates to report based on source definition, only 289 or 51 percent of all processing facilities are expected to meet or exceed the 25,000 Mt CO2e threshold. As such, EPA disagrees with the commenter's conclusion that nearly 100 percent of gathering and processing facilities must report.

Comment Number: EPA-HQ-OAR-2009-0923-1100-1
Organization: Linn Energy
Commenter: Paul M. Espenan

<u>Comment Excerpt Text:</u>
LINN Energy believes that EPA has not matched the rigor and cost of proposed emission-estimating methods to potential emissions. As a result, the regulatory burden and associated costs to operators, in particular smaller companies, of stripper wells, is disproportionate to the benefit. As proposed, EPA makes no adjustment to estimation methods so that the amount of effort is appropriate given the potential emissions.

Response: EPA is unable to evaluate the comment regarding the rigor of the Agency's cost estimates because the commenter did not provide any specific information to explain their conclusion. Please see EPA-HQ-OAR-2009-0923-1005-7 for EPA's response to comments on the rule's impacts on small entities; EPA-HQ-OAR-2009-0923-0053-1 for EPA's response to comments on rule's impacts on operators of marginal wells; EPA-HQ-OAR-2009-0923-1010-2 and EPA-HQ-OAR-2009-0923-1080-49 for EPA's response to comments regarding the rule's costs and steps the agency took to minimize the burden while ensuring the program will yield high quality data.

Comment Number: EPA-HQ-OAR-2009-0923-1151-14
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Regulatory Flexibility Act (RFA)

The RFA 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.[127] A small entity is defined as a small business, small organization and/or a small governmental jurisdiction, which include many small owners and operators of onshore and offshore petroleum and natural gas facilities.[128] EPA failed to conduct a regulatory flexibility analysis of the proposed Subpart W, because it "certifi[es] that this action will not have a significant economic impact on a substantial number of small entities."[129] However, EPA dramatically undercounted the burdens to small businesses who own and/or operate petroleum and natural gas systems, who will be dramatically impacted by the rule's unprecedented monitoring, recordkeeping, and reporting requirements for small entities. EPA is obligated to at least repeat its analysis using more accurate economic impact data in order to truly determine whether the proposed rule impacts small businesses.

Response: EPA disagrees with this comment. First, EPA analyzed the economic impact on small entities using the revised cost estimates discussed in preamble Section III and in the EIA. These cost estimates reflected improvements made in response to comments as well as changes to the monitoring requirements in today's final rule. See preamble III.D for further discussion about EPA's compliance with the Regulatory Flexibility Act; Section IV of the preamble and Sections 5.2 and 6.3 of the Economic Impact Analysis document in detail the analysis EPA conducted in accordance with the Regulatory Flexibility Act. .

In addition, EPA determined that screening tools would facilitate reporting determinations and plans to make such tools available. In particular, the screening tools will assist small entities in determining whether or not they meet the threshold. EPA expects the screening tools will assist most marginal operators in their threshold determination. See EPA's complete response in Section III.B.2 of the preamble to today's final rule.

Overall, this analysis is consistent with EPA's conclusion that today's final rule will not have a significant economic impact on a substantial number of marginal U.S. operators. Please see EPA's response to EPA-HQ-OAR-2009-0923-0053-1 for further discussion about Subpart W's effect on marginal wells. In short, EPA has thoroughly analyzed the rule's potential impact on small entities and determined that the impact on small businesses will not be significant.

Comment Number: EPA-HQ-OAR-2009-0923-1151-78
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
W17. (Preamble p. 118) We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.
To minimize a competitive disadvantage targeting larger entities, the API does not object to implementing the rule on small entities.

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[127] 5 U.S.C. Sections 603(a) & 605(b).

[128] 5 U.S.C. Section 601(6).

[129] 75 Fed. Reg. 18,631.

Response: EPA appreciates the commenter's interest in the rule's potential impacts on small entities. The Economic Impact Analysis (Sections 5.2 and 6.3) document EPA's analysis of such impacts.

10.6 BENEFITS FOR SOCIETY

Comment Number: EPA-HQ-OAR-2009-0923-1074-18
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
What are the benefits of the proposed rule for society?

Comment: WBIH takes exception to EPA's statement: "A mandatory reporting system for petroleum and natural gas systems will benefit the public by increased transparency of facility emissions data."

Air quality permitting and compliance programs are in place, and specific facility emissions information is already available for public review

Response: EPA disagrees with this comment. GHG emissions were not required to be measured or reported under any federal Clean Air Act regulatory program until promulgation of 40 CFR part 98. Although the GHG Reporting Program (40 CFR part 98) is unique, EPA considered other federal and state programs during development of both the GHG Reporting Rule (74 FR 56260) and Subpart W, and how these existing programs treat the petroleum and natural gas industry. EPA concluded that the addition of Subpart W to 40 CFR part 98 will supplement rather than duplicate other U.S. government GHG programs. Preamble Section I.B discusses EPA's authority to collect these data and the potential uses for the data, including informing both improvements in sector based non-regulatory strategies and technologies for preventing or reducing air pollutants, and potential policy and regulatory actions to address greenhouse gas emissions. See Section 2 of the Economic Impact Analysis for a detailed discussion about EPA's consideration of other federal and state GHG reporting programs.

Section III.E of the preamble summarizes the anticipated benefits of today's final rule, which include providing the government with sound data on which to base future policies and providing industry and the public independently verified information documenting firms' environmental performance.

Comment Number: EPA-HQ-OAR-2009-0923-1082-3
Organization: MidAmerican Energy Holdings Company
Commenter:

<u>Comment Excerpt Text:</u>
It is necessary and appropriate to consider the underlying objectives of the requirement to measure and report greenhouse gas emissions in the development of the underlying reporting requirements. MidAmerican is concerned about EPA's suggestion that societal benefits of the proposed rule include allowing citizens, community groups and labor unions to "negotiate directly with polluters to lower emissions, circumventing greater government regulation" and that "publicly available emissions data also will allow individuals to alter their consumption." As

an initial matter, emission reductions are an issue that should be subject to transparent debate and should reflect the informed policy decisions of elected lawmakers and reporting should serve these policy objectives, not the objectives of citizens, community groups and labor unions outside the recognized legislative and regulatory processes.

Response: This comment provides an incomplete quote from the rule and therefore mischaracterizes EPA's discussion about the rule's anticipated benefits. As discussed in Section VII.E of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) and in Section III.E of the preamble to today's final rule for Subpart W, EPA considered the benefits of reporting. These Sections present the results of EPA's systematic literature review of existing studies about the benefits of a reporting system. One example of the benefits identified by the literature review is that a "mandatory reporting system will benefit the public by increased transparency of facility emissions data. Transparent, public data on emissions allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers."

Please refer to Section III.E of today's final rule for a complete discussion about the anticipated benefits for industry, government, and the public; EPA's response to EPA-HQ-OAR-0923-1074-18 for further details about the benefits.

10.7 GENERAL COMMENTS ON COSTS AND ECONOMIC IMPACTS

Comment Number: EPA-HQ-OAR-2009-0923-0061-2
Organization:
Commenter: A. Potts

Comment Excerpt Text:
The problems that I see with this proposed rule are that it does nothing to tackle what is truly at issue, imposes additional costs on business that will be passed along to the consumer, relies on an assumption that these GHG emissions are behind the recent climate change and lack of cooperation with business.

Response: EPA does not agree with the comment. Please see EPA-HQ-OAR-2009-0923-1303-2, for EPA's response to the comment regarding compliance costs and pass through of these costs to consumers. Regarding the comment about the science of climate change, this rule is not the appropriate forum for that discussion. EPA finalized findings that GHG emissions from new motor vehicles and engines contribute to air pollution which may reasonably be anticipated to endanger public health and welfare (74 FR 66496; December 15, 2009, "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act") (see Docket EPA-HQ-OAR-2009-0171). Prior to finalizing the endangerment finding, EPA received over 380,000 public comments, covering the issues raised by the commenters on this reporting rule and many others. EPA published responses to these comments in the Response to Comments documents, available at http://www.epa.gov/climatechange/endangerment.html. Finally, EPA disagrees that the data collected under this rule would not be useful. Data collection serves as the first step in developing sound policy. For a complete discussion about the benefits of the rule and expected to use of the data, see EPA's response to EPA-HQ-OAR-2009-0923-1074-18.

Comment Number: EPA-HQ-OAR-2009-0923-0061-3
Organization:
Commenter: A. Potts

Comment Excerpt Text:
The EPA should work in conjunction with business to come up with viable solutions for inexpensive and effective ways to monitor the CO2 output. Over-regulation and the cost of compliance has driven many businesses overseas seeking less stringent regulations causing Americans lost jobs while the earth is becoming more and more polluted.

Response: This final action does not regulate GHG emissions; rather it gathers information to inform EPA's evaluation of various CAA provisions. See Section I.C of this preamble for complete discussion about the legal authority for the rule.

In addition, EPA has conducted extensive outreach with industry and other stakeholders to develop reliable and cost-effective methods to monitor GHG emissions. EPA evaluated the requirements of existing GHG reporting programs, obtained input from stakeholders, analyzed reporting options, and developed the general reporting requirements and specific requirements for each of the GHG emitting processes listed in Subpart W. EPA also considered public comments it received on the April 2009 (74 FR 16448; April 4, 2009) and April 2010 (75 FR 18608; April 12, 2010) proposed rulemakings as it determined the reporting requirements issued in today's final rule. See Section 2 of the Economic Impact Analysis for a detailed summary of EPA's proactive communications outreach program and solicitation of stakeholder input (EPA-HQ-OAR-2009-0923). Finally, see EPA-HQ-OAR-2009-0923-1010-2 for EPA's response to comments about its efforts to reduce the burden and costs of the rule, while still ensuring that the program yields high quality data and essential information.

Comment Number: EPA-HQ-OAR-2009-0923-1016-1
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
Natural Gas Distribution and Storage Are a Vital Part of the Solution for Reducing GHG Emissions; Reporting Burdens Should be Assessed in that Context

Natural gas is the most efficient of the fossil fuels, especially when used directly by residential and commercial consumers. Approximately 90% of the energy value of natural gas is delivered to consumers. In contrast less than 30% of the primary energy involved in producing electricity reaches the consumer.

Natural gas is clean, efficient, abundant, and domestic. When burned, natural gas is the most environmentally-friendly fuel because it produces low levels of unwanted byproducts (SOx, particulate matter, and NOx) and less carbon dioxide (CO_2) than other fuels. Upon combustion natural gas produces 43% less CO_2 than coal and 28% less than fuel oil.

Natural gas is also an abundant fuel. Recent prodigious discoveries of shale gas have significantly added to this abundant resource base. Changes in economics and technology will continue to increase our resource base estimates in the future, as they have consistently done in the past.

Natural Gas is a domestic resource. Almost all of the natural gas that is consumed in America is produced in North America, either in the United States or Canada, with the vast majority of that being produced in the United States. Only a small portion—1 to 2%— is imported from abroad as liquefied natural gas.

Natural gas is an essential fuel for America. The natural gas delivered by AGA members to residential and commercial customers is consumed almost entirely to meet essential human needs—space heating, water heating, and cooking.

America's natural gas utilities and residential customers have led the nation in reducing the emission of greenhouse gases over the last 40 years and can continue, with appropriate policies, to reduce those emissions. It takes less natural gas to serve 65 million homes today than it took to serve about half that number in 1970. Natural gas is more than just a "bridge" to a low carbon future; rather, it is part of the climate change solution now and in the future, because it uses existing technology and offers an immediate carbon reduction benefit since it has the smallest carbon footprint of all fossil fuels.

It is important in crafting the reporting rules in Subpart W not to lose sight of this important context for energy and environmental policy. In June 2009, AGA filed detailed comments on EPA's April 2009 Proposed Rule for Mandatory Reporting of Greenhouse Gases (MRR),[130] including comments on proposed Subparts, A, C, NN and W. As we said then, when crafting GHG reporting rules, it is important that EPA not inadvertently impose barriers that could keep society from reaping the full benefit of using clean, efficient, abundant and domestic natural gas to reduce our nation's carbon footprint. Greenhouse gas reporting rules should not create disincentives to lowering US GHG emissions by imposing unnecessary costs on the storage and distribution of natural gas to customers, thereby raising gas utility bills and discouraging the use of natural gas. Instead, sound public policy should encourage the efficient, direct use of natural gas by customers to reduce overall greenhouse gas emissions.

Response: EPA disagrees that today's final rule imposes unnecessary costs on the storage and distribution of natural gas to customers. EPA documents its assumptions and methods to

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[130] EPA Proposed Rule, Mandatory Reporting of Greenhouse Gases – 40 CFR Parts 86, 87, 89, et al. 74 Fed. Reg. 16448 (April 10, 2009).

demonstrate industry burden in the Economic Impact Analysis of the rule making docket (EPA-HQ-OAR-2009-0923) and clarifies several requirements related to natural gas distribution that reduce the burden to much lower than many commenters assumed; please see Sections II.F and III.B of the Preamble; EPA-HQ-OAR-0923-1016-11 also discusses EPA's analysis of costs for the distribution segment. In addition, see EPA-HQ-OAR-2009-0923-1010-2 and EPA-HQ-OAR-2009-0923-1080-49 for EPA's response to comments regarding the rule's costs and steps the agency took to minimize the burden while ensuring the program will yield high quality data. Furthermore, EPA has considered the potential impact of the rule on natural gas consumers; see EPA-HQ-OAR-2009-0923-1010-2 and EPA-HQ-OAR-2009-0923-1303-2 for complete discussion.

Finally, see today's preamble Section III.E for the benefits of this rule to society.

Comment Number: EPA-HQ-OAR-2009-0923-1082-1
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
MidAmerican's experience with reporting greenhouse gas emissions suggests that the requirements and level of detail associated with a particular reporting scheme will dramatically impact the time spent on measurement and report preparation, as well as the costs associated with reporting. Requiring entities to focus on emissions calculations and reporting of extremely small potential sources of emissions disproportionately impacts the costs of the reporting requirement with very insignificant benefits.

MidAmerican's experience also suggests that mandatory reporting results in higher costs. While EPA has not proposed to require third-party verification of emissions data (a position supported by MidAmerican), it is important to note that given the compliance certification requirements, additional time and resources are likely to be necessary to satisfy corporate reporters and their stakeholders that the reported data is accurate. This added burden arises not only from the direct activities associated with reporting, but also from the indirect activities associated with maintaining compliance management systems and auditing compliance with the reporting program.

As noted by EPA, the initial cost of reporting (which MidAmerican believes is severely underestimated) is significant--$56.0m in the first year. This initial $56.0m cost and subsequent annual cost, estimated by EPA to be $21.0m, will do nothing to reduce greenhouse gas emissions particularly when, as admitted by EPA, the "benefits are very difficult to quantify and monetize." MidAmerican supports transparent and consistent reporting; however, the level of detail should not be so burdensome that it dramatically increases costs or risks to the reporting entity that fail to take into account the associated benefit.

Response: EPA disagrees that the Agency significantly underestimated the costs of reporting. See Section III.B.2 of the preamble for EPA's response to this comment and others that said the Agency underestimated the costs; see EPA's response to EPA-HQ-OAR-2009-0923-1074-18 for a complete discussion about the benefits of the rule and expected to use of the data. Also, Section 5 of the Economic Impact Analysis (EPA-HQ-OAR-2009-0923) presents the updated national compliance cost estimates for today's final rule and a summary of the benefits. In addition, see EPA-HQ-OAR-2009-0923-1010-2 for EPA response to comments about the need to consider the burden and costs of the rule as well as the benefits.

Regarding the comment on the time and cost for a facility to comply with the rule, EPA has in substantially reduced burden of today's final rule by simplifying the requirements for reporting of emissions. Please see preamble Section II, for further details on the changes in the rule that will result in significantly lower burden to reporters.

EPA appreciates the comments on third-party verification and note that today's final rule relies on EPA verification; see Section II.D of the preamble. See also preamble Section II.N to today's final rule promulgating 40 CFR part 98 for details about the basis for EPA verification (74 FR 56260; October 30, 2009).

Finally, EPA does not agree with the comment about GHG reductions and benefits to society. In particular, the comment misrepresents EPA's statement that the rule "benefits are very difficult to quantify and monetize." EPA's statement refers to the challenges associated with quantifying and monetizing the benefits, but these challenges do not mean that there are *no* benefits expected from the rule. Data collection serves as the first step in developing sound policy. For a complete discussion about the benefits of the rule and expected to use of the data, see EPA's response to EPA-HQ-OAR-2009-0923-1074-18.

Comment Number: EPA-HQ-OAR-2009-0923-1174-1
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text:
Devon Energy Corporation (Devon) has serious concerns about the U.S. Environmental Protection Agency's ("EPA") proposed rule entitled Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, published at 75 Fed. Reg. 18608 (April 12, 2010) and therefore appreciates the opportunity to provide these comments. Our concerns are focused on the unnecessarily high cost to comply with this complex rule.

Response: EPA does not agree with the comment. Please see EPA's response to EPA-HQ-OAR-2009-0923-1174-4 for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1174-4
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text: Devon has elected to submit these separate comments because we are convinced of the importance of emphasizing our concern that this proposed rule will impose significant and unnecessary cost on our industry that will ultimately have negative natural gas supply impacts at a time when US climate policy demands this low carbon fuel.

Response: EPA does not agree with the commenter. The commenter has not provided any information regarding why or how it believes that gas supply will be impacted. Please see the memo "Subpart W Greater Economic Impact" under docket EPA-HQ-OAR-2009-0923 and EPA's response to EPA-HQ-OAR-2009-0923-1303-2 and EPA-HQ-OAR-2009-0923-1010-2 for further discussion.

Comment Number: EPA-HQ-OAR-2009-0923-1300-1
Organization: Texas Oil and Gas Association
Commenter: Deb Hastings

Comment Excerpt Text:
TxOGA concurs with the detailed comments submitted by the American Petroleum Institute (API) and agrees that the U.S. EPA has significantly underestimated the burden and cost of the proposed new mandatory reporting requirements of greenhouse gases for petroleum and natural gas systems.

Response: EPA does not agree with the comment. Please see EPA's response to EPA-HQ-OAR-2009-0923-1151-107.

Comment Number: EPA-HQ-OAR-2009-0923-1300-5
Organization: Texas Oil and Gas Association
Commenter: Deb Hastings

Comment Excerpt Text:
When re-structuring the rule for re-proposal, EPA should take all opportunities to simplify the requirements and reduce burden.

Response: EPA has simplified reporting requirements in today's final rule to reduce burden. Please see preamble Section II, for more details.

VOLUME 11: DESIGNATED REPRESENTATIVE AND DATA COLLECTION, REPORTING, MANAGEMENT, AND DISSEMINATION

11.0 DESIGNATED REPRESENTATIVE AND DATA COLLECTION, REPORTING, MANAGEMENT, AND DISSEMINATION

No Comments Received.

11.1 DESIGNATED REPRESENTATIVE (AUTHORIZATION AND RESPONSIBILITIES)

Comment Number: EPA-HQ-OAR-2009-0923-1151-11
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Reporting Contractor Emissions

i. EPA Lacks the Authority to Require Subpart W Facilities to Report Contractor Emissions

On its face, CAA Section 114 does not provide EPA with the authority to require owners or operators of facilities, including the facilities covered by proposed Subpart W, to report GHG emissions generated by contractors. CAA Section 114 plainly states that the Administrator may only require monitoring, reporting, and recordkeeping submissions from any person who "may have the information necessary for the purposes set forth in [CAA Section 114(a)(1)]." 42 U.S.C. Section 7414(a)(1). The intent of Congress is clear—CAA Section 114(a)(1) requirements only extend to those who may actually possess such information necessary for the purposes listed in that provision. Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc., 467 U.S. 837, 842-43 ("If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress."). As a general principle, owners and operators of facilities often do not have access to the records of independent contractors. In particular, reporting entities will often be unable to obtain from independent contractors the detailed and often confidential information required to be reported under proposed Subpart W, including emissions and equipment data. Therefore, EPA lacks the authority to broadly mandate that all facilities produce and certify emissions data from contractors.

ii. Requiring Reporting of Contractor Data is Unreasonable and Impractical

As a practical matter, EPA's concept of a "designated representative" and the requirement that the designated representative "certify" contractor GHG emission reports is unreasonable and impractical. The designated representative may have limited or no knowledge of the contractor's operations, the contractor's potential GHG sources and associated data collected for reporting, the quality and completeness of the data collected, quality and completeness of the verification, and/or the environmental matters of the contractors. The proposed rule sets an unrealistic expectation for the role of the designated representative. 40 CFR Section 98.4(e)(1) includes a certification statement containing the following language:

"...I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete…"

This language sets an inappropriate standard for the owner or operator of a facility, or his/her "designated representative" in terms of managing contractor data. No high-level management official has the authority, time, or expertise to "personally examine" emissions information from contractors, which is necessary to prepare the emissions report. This is particularly the case with regards to onshore and natural gas production facilities, which may contain thousands of sources, operated often by contractors, scattered across an entire geologic basin.

Response: With respect to comments regarding EPA's authority to require reporting of contractor emissions, please see the response to EPA-HQ-OAR-2009-0923-1151-10.
With respect to comments about the designated representative certifying contractor emissions, please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-1060-3
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
General Comments – Certification by a "Designated Representative"

As proposed, this rule will require owners (i.e. Yates) of a site to report GHG emissions resulting from rental and portable equipment located at a well head. Often, the owner (Yates) of the site does not have emission information, or relies on information provided by a rental company (i.e., Compressor Systems, Inc.) that may or may not be accurate or acceptable by EPA standards. 98.4(e) requires that emissions reports be certified by a "Designated Representative." Yates' Designated Representative must therefore ultimately certify emissions for units they do not control, and there is no guarantee those emissions are auditable, verifiable, etc. Yates requests that the EPA clarify that emissions from equipment that is on-site, but not under common ownership, does not need to be reported by the site owner.

Response: The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final Rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-16.

11.2 PROCESS FOR DATA COLLECTION/REPORTING, MANAGEMENT, AND DISSEMINATION

Comment Number: EPA-HQ-OAR-2009-0923-1039-36
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Reporting, Recordkeeping and Missing Data Provisions include Requirements that Are Infeasible, Costly, or Not Warranted to Support Mandatory Reporting Rule Objectives

Reporting and recordkeeping requirements are identified in §98.236 and §98.237. Missing data procedures are identified in §98.235. INGAA recommends revisions or clarification to these sections to eliminate requirements that are not practical or do not add substantive value while incurring.

Response: EPA does not agree that the reporting and recordkeeping requirements, nor the missing data provisions, are infeasible or impractical. See response to comment EPA-HQ-OAR-2009-0923-1151-5 and the preamble of today's final rule, Section II.F for more information.

Comment Number: EPA-HQ-OAR-2009-0923-1298-76
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
Annual Report Due Date: Given the vast amount of information that must be collected and compiled, IPAMS does not believe that three months is sufficient time to collect, calculate and QA/QC the data needed to develop and submit a report. In addition, many industries are already obligated to submit several data-intensive reports to various agencies, including EPA, in the first quarter of the year. These include Title V semi-annual monitoring reports and annual certifications under the CAA; quarterly deviation reports under the CAA; Discharge Monitoring Reports under the Clean Water Act; and Tier II reports under the Emergency Planning and Community Right-to-Know Act. IPAMS requests that EPA require annual reports to be submitted by June 30th of each year. This date would be consistent with other registry programs, such as that established by The Climate Registry.

Response: EPA will allow the application for the use of best available monitoring methods for certain sources. Please see the preamble Section II.F. EPA expects reporters to meet the annual reporting due date, which is consistent with the reporting dates in The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98); , preamble Section II.J. In addition, EPA has modified certain methodologies for specific emission sources that will reduce burden. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1011-1
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>

Preamble Section II.(A.) on page 18612.—(KEY ISSUE) El Paso requests the EPA establish a June 30 submittal deadline for all emission reports related to Subpart W.

Response: EPA disagrees with a June 30 reporting deadline, please see the response to comment EPA-HQ-OAR-2009-0923-1298-76. EPA will allow the application for the use of best available monitoring methods for certain sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1098-4
Organization: Southern Union Company
Commenter: Charles Wait

Comment Excerpt Text:
Of additional concern with the proposed schedule is the data warehousing of fugitive and vented emissions. SU has a team focused on developing a GHG database; however, the focus is primarily on combustion emissions through 2010. SU may be hard pressed to complete an inventory of vented and fugitive sources and install these sources in a database by year's end. EPA must realize that all source categories listed in the proposed Subpart W have no current regulatory requirement to be considered in an emission inventory. Adding these sources to the database will require a resource intensive ground up effort that may produce a less than accurate inventory if full implementation is required in the first year.

Response: In certain cases, EPA is allowing for additional time to follow all of the methods in the rule, please see Section II.F of the preamble for information on use of best available monitoring methods. In addition, EPA has taken a number of other steps to reduce the reporting burden (while sustaining the necessary quality of data). Please see the Section II.F of the preamble. With the revision of the rule to allow the use of best available monitoring methods and other reduced reporting requirements, and the use of standard spreadsheets and databases that are readily available at retail stores, EPA does not anticipate that reporters will bear excessive costs to complete an inventory of GHG emissions in time to record and report this inventory by March 31, 2012, please see the Section III.B of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1151-62
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.236(c) Data reporting requirements for (17) compressor wet seal degassing vents and (18) reciprocating compressor rod packing. The total throughput of the compressor whose emissions are reported is required under this section. This throughput is not part of the emission estimation methods under Section 98.233 (o) and (p). In addition, Section 98.236 makes no reference to flow meters under Section 98.234(b). As a result, API interprets the requirements under Section 98.236(c) to allow the use of engineering estimates for determining these throughputs. API requests confirmation from EPA that engineering estimates may be used under Section 98.236(c).

Response: Regarding the comment on compressor throughput meters, please see EPA-HQ-OAR-2009-0923-1206-63.

Comment Number: EPA-HQ-OAR-2009-0923-1074-42
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.236:
WBIH requests clarification on any reference to component "counts." When referencing component counts, WBIH requests the addition of the word "leaking", i.e. 98.236(c)(19)(i) should read, "component count for each leaking fugitive emission source."

Response: EPA has clarified the data reporting requirements for leak detection and emission factors, to require the "total number of this type of emission source found to be leaking."

Comment Number: EPA-HQ-OAR-2009-0923-1305-34
Organization: BP America, Inc.
Commenter: Karen St. John
Comment Excerpt Text:
Section 98.233(e) and Section 98.236(c)

Glycol Dehydrators: BP supports EPA's approach of restricting calculation of emissions to those dehydrators without thermal control or vapor recovery on the overhead vent stream. However, Section 98.233 (e)(2) appears to directly conflict with this approach by specifying how to calculate emissions if the dehydrator overhead is routed to a flare or burner (thermal control). In addition, the reporting requirements for glycol dehydrators under Section 98.236(c)(5) do not explicitly contain an equivalent limitation or limit reporting to only those dehydrators for which emissions must be calculated. BP requests that EPA address the conflict between Section 98.233(e) and Section 98.233(e)(2) along with making the appropriate limitation on dehydrators would be required to report explicit in 98.236(c)(5) .

Response: EPA has reviewed the comment, and in today's final rule has clarified the Section outlining the calculation of GHG emissions from dehydrator vents and includes calculation of emissions from dehydrator vents without vapor recovery or thermal control devices.

Comment Number: EPA-HQ-OAR-2009-0923-1015-35
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
General Comments – Data Reporting Requirements

98.236(f) requires operators to report emissions separately for portable equipment such as drilling rigs, dehydrators, compressors, electrical generators, etc. However, as this rule (at this time) is only for the reporting of GHG emissions, the types of equipment emitting the GHGs is irrelevant. Furthermore, this requirement would require installation of fuel meters on equipment that otherwise would be included in the site-wide fuel usage. PAW proposes that all fuel use at a site be provided to the EPA as a single figure and not separate out portable equipment.

98.237(f) requires calibration reports for detection and measurement instruments used. Would calibration reports for detection and measurement instruments also require companies to retain records for every single pressure gauge? That is a tremendous amount of information that does not impact GHG emissions from a site.

Response: EPA disagrees, as the primary intent of the Mandatory Reporting Rule is to inform future policy, and EPA deems it appropriate to require separate reporting for emissions from portable equipment. It is estimated that portable non self-propelled equipment is responsible for over 45 percent of total emissions from onshore petroleum and natural gas production, please see "Portable Combustion Emissions" docket EPA-HQ-OAR-2009-0923. In addition, the commenter made assumptions which were not consistent with the proposed rule's intent. One was the assumption that portable equipment would need a meter to determine the volume of fuel combusted. Reporters are not required to install a fuel meter. EPA has clarified this in today's final rule and allows reporters to use engineering calculations based on best available data to determine the amount of fuel combusted. EPA will also allow for certain sources best available monitoring methods. Please see the preamble Section II.F. Finally, EPA has conducted a review of the emissions contribution relative to reporting burden and has modified today's final rule for onshore production and natural gas distribution, and does not include emissions from external combustion equipment that have a rated heat capacity equal to or below 5 mmBtu/hr, please see "Equipment Threshold for Small Combustion Units" docket EPA-HQ-OAR-2009-0923. However, equipment that are at or fall below the specified mmBtu/hr level will be required to report activity data by type of combustion equipment. With regard to retention of records for every single pressure gauge, please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98); October 2009 response to comment EPA-HQ-OAR-2008-0508-0504.1 excerpt 20 in the Content of the Annual Report Section.

Comment Number: EPA-HQ-OAR-2009-0923-1060-10
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
General Comments – Data Reporting Requirements

98.236(f) requires operators to report emissions separately for portable equipment such as drilling rigs, dehydrators, compressors, electrical generators, etc. However, as this rule (at this time) is only for the reporting of GHG emissions, the types of equipment emitting the GHGs is irrelevant. Furthermore, this requirement would require installation of fuel meters on equipment that otherwise would be included in the site-wide fuel usage. Yates proposes that all fuel use at a site be provided to the EPA as a single figure and not separate out portable equipment.

98.237(f) requires calibration reports for detection and measurement instruments used. Would calibration reports for detection and measurement instruments also require YPC to retain records for every single pressure gauge? That is a tremendous amount of information that does not impact GHG emissions from a site.

Response: EPA disagrees that all fuel use at a site be reported to the Agency as a single figure and not separate out portable equipment. Please see the response to comment EPA-HQ-OAR-2009-0923-1015-35.

Comment Number: EPA-HQ-OAR-2009-0923-1027-17
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.237: In addition to the information required by § 98.3(g), you must retain the following records:
(a) Dates on which measurements were conducted.
(b) Results of all emissions detected and measurements.
(c) Calibration reports for detection and measurement instruments used.
(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

OOC Comment: The rule should clarify what, if any, additional information must be retained under 98.237 for offshore platforms. In the preamble, the term "'measurements" seems to refer to direct emissions measurements. However, the GOADS process is centered around reporting activity data to MMS for emissions calculations and not direct emissions measurements.

Response: With regard to recordkeeping requirements, offshore reporters must retain the information required under 98.3(g). Offshore petroleum and natural gas production must also retain the records as set forth by MMS in compliance with 30 CFR 250.302 through 304. Not all methods in today's final rule require data collection such as measurement, emissions detection, or instrument calibration. Therefore reporters do not need to retain such records where not required by methods. However reporters in state and non-Gulf of Mexico waters must calculate their emissions using GOADS methodologies, and therefore must also retain the inputs and outputs of those calculations. In addition, reporters subject to GOADS and reporters in state and non-Gulf of Mexico waters must also retain the inputs and outputs of calculations required to adjust emissions in years between GOADS cycles.

Comment Number: EPA-HQ-OAR-2009-0923-1024-49
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
SECTION 98.237 Records that must be retained.

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

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements. Video records of optical imaging surveys are not required to be retained.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

Response: Regarding the suggestion on video records, EPA has clarified the rule, such that video records of leak detection surveys with optical gas imaging instruments are not required to be made or retained. Please see the data reporting requirements in today's final rule in Section 98.236.

Comment Number: EPA-HQ-OAR-2009-0923-1024-37
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

<u>Comment Excerpt Text:</u>
Retention of Video Records. The preamble to the rule suggests that video records of optical leak surveys showing emissions must be retained;[131] however, this requirement is not expressed in the text of the rule itself. Moreover, it is not clear whether EPA intends for reporting entities to keep records of all optical gas images taken at each facility, or only those images that reveal leaking components. Kinder Morgan believes that this provision should be omitted from today's final rule, given the space requirements for the video data and the fact that many optical imaging devices lack a recording feature. Kinder Morgan's experience is that video images from an optical gas imaging instrument require on the order of over 3 megabytes of space per minute of video. Video records of entire optical leak surveys will be in the gigabyte size range. Keeping complete survey video records for multiple years at multiple facilities will require exceptionally large electronic storage space. If EPA rejects this recommendation and elects to require retention of optical gas imaging records, EPA should amend the text of the rule to clarify that only images that reveal leaks need to be kept.

Response: EPA has clarified the rule, such that video records of leak detection surveys with optical gas imaging instruments are not required to be made or retained.

Comment Number: EPA-HQ-OAR-2009-0923-1040-22
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

<u>Comment Excerpt Text:</u>
98.236(c)(7)-(8): Consistent with the preceding comment, there is no need to track well completions and workovers based on whether a well is "conventional" or "'unconventional." We

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[131] Proposed Subpart W, 75 Fed. Reg. at 18,625.

request that EPA remove the sub-bullets (i) and (ii) from both paragraphs.

Response: EPA disagrees, and has clarified today's final rule to continue to include data reporting requirements for well completions and workovers as identified as "with and without hydraulic fracturing." The emissions profile from these two sources is very different, and this data is needed to inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-1018-23
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (b): CAPP noticed that the EPA has requirements for low bleed device venting referenced in two sections: 98.233(r) and 98.233(b). Based on the redundancy of this requirement and to guard against double reporting of emissions CAPP recommends that the requirements only be reported in one section.

Response: EPA has clarified today's final rule such that natural gas driven pneumatic devices have been consolidated to all report under Section 98.233(a).

Comment Number: EPA-HQ-OAR-2009-0923-1018-37
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
CAPP also proposes the following rewording of 98.233(n)(8): "Any emissions calculated under this source are excluded from other emission sources in 98.233" and that if a source is covered elsewhere but is sent to flare, reporters be given the choice of where / how to report it, based on ease of reporting.

Response: EPA has reviewed the comment and has clarified Section 98.233(n) of today's final rule such that flare emissions determined under paragraph (n) must be corrected for flare emissions calculated and reported under other paragraphs to avoid double counting of these emissions.

Comment Number: EPA-HQ-OAR-2009-0923-0963-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
Reporting: Will the EPA be sending out standardized report forms for operators to fill out

Response: No, EPA will not be issuing reporting forms. The reports must be submitted electronically. Please see The Mandatory Reporting of Greenhouse Gases Rule, ("Final MRR"), (40 CFR part 98) preamble Section II.A.

Comment Number: EPA-HQ-OAR-2009-0923-1080-53
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Aka recommends deleting § 98.236(d). This paragraph (d) requests "minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section." This is a very vague request and has no apparent meaning for most of the operations described in (a)(1) through (a)(8). In addition, this information does not appear to be useful in determining or understanding the GHG emissions information that is otherwise reported.

Response: EPA has revised 98.236(d) in today's final rule to only require reporting of annual throughput, as determined by engineering estimates based on best available data.

11.2.1 DATA COLLECTION METHODS (COMMENTS ON SECTION VI.B OF THE PREAMBLE)

Comment Number: EPA-HQ-OAR-2009-0923-1171-6
Organization: Western Resource Advocates
Commenter: Robert Harris

Comment Excerpt Text:
Source data on federal and state public lands should be aggregated by the relevant management area, or disaggregated, so as to be useful to land management agencies.

EPA should collect information on the GHG emissions of onshore production facilities located on public lands in a form that may be useful to other agencies conducting relevant analyses, including under the National Environmental Policy Act ("NEPA"), 42 U.S.C. §§ 4321 to 4370f.

The American Association of Petroleum Geologist's definition of a "basin" may not adequately assist land management agencies in meeting their statutory obligations. For example, the basin boundaries may not match Bureau of Land Management ("BLM") field office boundaries or the boundaries of national forests. Because the Proposed Rule would require reporting only aggregated emissions data, land management agencies may not be able to readily divide the data for an accurate estimate of GHG emissions occurring on only part of a basin within the relevant national forest or management area. Therefore, emissions reports may not be helpful for conducting or evaluating resource management plans or forest plans prepared under the Federal Land Policy and Management Act, 43 U.S.C. §§ 1701 to 1785, or the National Forest Management Act, 16 U.S.C. §§ 1600 to 1614, respectively.

To remedy this problem, EPA could require aggregated reporting of GHG emissions from oil and gas facilities on federal public lands to match the boundary of the relevant BLM field office or national forest. Alternatively, the Proposed Rule could require operators to "show their work" by attaching disaggregated well pad data as an appendix to the aggregated basin-wide report.

According to EPA, the agency did not reject the well pad option because it was infeasible, but rather because the considered reporting thresholds would result in either too many or too few reporters. 75 Fed. Reg. at 18615.

Other agencies could use the disaggregated location-specific well pad data to help quantify GHG emissions in the relevant BLM field office, national forest, or other geographic area. EPA's maintenance of a publicly accessible and searchable database, capable of providing flexible data outputs, would further maximize the utility of information collected by the EPA under the Proposed Rule by minimizing inefficient and duplicative efforts by government agencies and members of the public.

Response: Regarding the comment on EPA collection and sharing of data with other Federal, State, and regional programs, please see the Mandatory Reporting of Greenhouse Gases Rule, ("Final MRR"), (40 CFR part 98), preamble Section II.O. The petroleum and natural gas systems monitoring and reporting requirements in today's final rule, are being added to the GHG RP and will gather data to inform future policy and programs. EPA's decision to use American Association of Petroleum Geologist's definition of a basin, the EIA field definition, and data reporting level are discussed in the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). Today's final rule requires reporting at the basin level in order to manage burden and maintain consistency of the data received, and therefore cannot introduce additional facility definitions such as the suggested BLM field office boundaries, due to the additional burden and it will not increase the quality of data nor can EPA possibly take into account all possible reporting configurations that various parties desire and therefore basin-level reporting is the most appropriate option.

11.2.1.1 ELECTRONIC SIGNATURES

No Comments Received.

11.2.1.2 USE OF UNIQUE IDENTIFIERS

No Comments Received.

11.2.1.3 METRIC UNITS

No Comments Received.

11.2.1.4 DELEGATION OF AUTHORITY TO STATES FOR DATA COLLECTION

No Comments Received.

11.2.1.5 USE OF AN ELECTRONIC REPORTING SYSTEM

Comment Number: EPA-HQ-OAR-2009-0923-1010-8
Organization: Oklahoma Independent Petroleum Association
Commenter: Burckhalter

Comment Excerpt Text:
Report submittal. EPA proposes that all reports will be submitted electronically. This may be burdensome on some small businesses that don't have the staff, expertise or access to submit the data electronically. EPA should allow small businesses to submit a hard copy of the required information.

Response: Please see Section V.B of the preamble of The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98), promulgated on October 30, 2009, for a response to this comment.

11.2.2 DATA QA AND FEEDBACK BY EPA TO REPORTERS

No Comments Received.

11.2.3 DATA DISSEMINATION

No Comments Received.

11.2.3.1 DATA DISSEMINATION TO THE PUBLIC

Comment Number: EPA-HQ-OAR-2009-0923-0116-1
Organization:
Commenter: J. Andes

Comment Excerpt Text:
Clearly, the oil and gas industry will not voluntarily report this information to the American public. Therefore, the industry must be obligated by federal regulation and enforcement to make public the information

Response: For a response to this comment, please see the response to EPA-HQ-OAR-2009-0923-1015-27.

Comment Number: EPA-HQ-OAR-2009-0923-0803-1
Organization:
Commenter: C. Taylor

Comment Excerpt Text:

I further urge that the industry's reported emissions are made public as soon as possible, and that the combination of greenhouse gas emissions and pollution from accidents and spills be made public so that all the necessary changes in the regulation of this industry can be made NOW!

Response: For a response to this comment, please see the response to EPA-HQ-OAR-2009-0923-1015-27.

Comment Number: EPA-HQ-OAR-2009-0923-1448-2
Organization:
Commenter: K. Wolney

Comment Excerpt Text:
Your data collection methods should be unimpeachable and the results should be reported to the public so we can see the consequences of our dependence on oil.

Response: For a response to this comment, please see the response to EPA-HQ-OAR-2009-0923-1015-27.

11.2.3.2 SHARING OF DATA WITH OTHER STATE AND FEDERAL AGENCIES

Comment Number: EPA-HQ-OAR-2009-0923-0064-1
Organization:
Commenter: Anonymous

Comment Excerpt Text:
Public Citizen has noted that the Federal Energy Regulatory Commission; formerly the Natural Gas Act; illegally ruled in March 2004 that states have limited jurisdiction over the permitting and siting of Liquified Natural Gas facilities inside their borders. Since state and local governments already have inadequate input into these projects, how does a (proposed) federal regulation that will not require control of greenhouse gases; only requiring sources above “certain” threshold levels, to monitor and report emissions help local and state governments?

Response: For a response to this comment, please see Sections I.E, II.O, and V of the preamble to The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98); promulgated on October 30, 2009.

Comment Number: EPA-HQ-OAR-2009-0923-1171-7
Organization: Western Resource Advocates
Commenter: Robert Harris

Comment Excerpt Text:
GHG emissions data collected under the Proposed Rule should be in a format that can readily assist agency efforts to reduce GHG emissions.

Proper GHG emission data reporting on public lands could also assist sister agencies in their efforts to reduce GHG emissions. For example, on September 14, 2009, Department of Interior ("DOI") Secretary Ken Salazar announced the creation of the DOI Carbon Footprint Project ("Project"). The Project will "develop a unified greenhouse gas emission reduction program, including setting a baseline and reduction goal for the Department's greenhouse gas emissions and energy use." U.S. Dept. of Interior, Sec. Order No. 3289.3 By tailoring the Proposed Rule's reporting requirements with respect to facilities on public lands, EPA could help DOI establish an accurate baseline for existing GHG emissions on public lands as well as track progress toward accomplishing DOI's emission reduction goals.

Response: For a response to this comment, please see Sections V.A and V.B of the preamble of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), promulgated on October 30, 2009.

VOLUME 12: MONITORING AND QA/QC REQUIREMENTS

12.0 MONITORING AND QA/QC REQUIREMENTS

Comment Number: EPA-HQ-OAR-2009-0923-1024-10
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
As EPA has acknowledged, fugitive and vented GHG emissions from the petroleum and natural gas sector are inherently difficult to monitor and quantify. This difficulty is a function of both the facilities themselves, which are extremely complex and contain thousands of disperse and difficult-to-access components, and of the elusive nature of the emissions. Kinder Morgan described these problems in its comments on the original Subpart W proposed in spring 2009, noting that direct measurement of fugitive and vented emissions is inaccurate and unreasonably costly.[132]

Kinder Morgan appreciates EPA's consideration of industry comments on the original Subpart W proposal, and its attempt to address some of the problems with that original proposal in the newly proposed rule. As a general matter, Kinder Morgan supports EPA's proposal to require reporting only from those components of petroleum and natural gas facilities that are responsible for 80% of GHG emissions.[133] Compared to the original Subpart W, this streamlined approach should reduce the amount of effort and cost wasted on quantifying relatively trivial emission sources. In addition, Kinder Morgan strongly supports EPA's proposal to make use of engineering estimation and emission factors where possible.[134] These methods generally provide reliable emissions, are well-understood and widely used within the industry to create GHG emission profiles, and are far more practical and cost-effective than individual direct measurement at millions of individual components.

Response: EPA has reviewed and considered this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1024-46
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
SECTION 98.234 Monitoring and QA/QC requirements.

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[132] See Comments of Kinder Morgan on the original Subpart W, Document ID No. EPA-HQ-OAR-2008-0508-0370 (filed June 9, 2009).

[133] See Proposed Subpart W, 75 Fed. Reg. at 18,614.

[134] See Proposed Subpart W, 75 Fed. Reg. at 18,620 (noting that direct measurement is called for only where "no credible engineering estimation methods or emissions factors exist that can accurately characterize the emissions.").

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

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, SECTION 60.18 (i)(1) and (2) of the Alternative work practice for monitoring equipment leaks. ~~In addition,~~ You must operate the optical gas imaging instrument to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. In addition to the optical gas imaging instrument, alternative technologies may be used for fugitive emissions detection in accordance with a testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, GPA, etc.) and instrument manufacturer recommendations. These include, but are not limited to, organic vapor analyzers, portable hydrocarbon gas detectors, ultrasonic leak meters, ultrasonic acoustic detectors, and soap solution.

(2) [Reserved]

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

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

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1305-29
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Section 98.234 Monitoring and QA/QC requirements

In reviewing the scope of the GHG Monitoring Plans, we are concerned about the workload associated with developing and maintaining the GHG Monitoring Plans. The scope of the monitoring plans make sense at the traditional CAA facility level, however the burden associated with keeping them up to date, coupled with their diminished value as their size increases could make them essentially useless at the hydrocarbon basin level. We would support breaking the geographic extent of the monitoring plan scope down to a lower, more operationally relevant basis, such as the sub-basin groupings described previously.

Response: EPA disagrees with the comment regarding the monitoring plan. Please see the Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.I.

12.1 METHODOLOGY USED TO DETECH GHG EMISSIONS

Comment Number: EPA-HQ-OAR-2009-0923-1008-2
Organization:
Commenter: J. Sizelove

Comment Excerpt Text:
EPA should require direct measurement of emissions. Using equations to estimate emissions is inaccurate. We need direct measurements to ensure the data is accurate to develop the best policy.

Response: EPA disagrees that direct measurement is appropriate for all emissions sources or the most cost-effective way to inform future policy. Each source in today's final rule has a carefully considered methodology that is sufficiently accurate and cost-effective to provide the information EPA needs for future policy. In some cases, engineering models or calculations are more accurate than spot direct measurements, and continuous measurement on the enormous number of individual emission sources is not at all practical or necessary. For further information please see the response to EPA-HQ-OAR-2009-0923-1155-10.

Comment Number: EPA-HQ-OAR-2009-0923-1039-18
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Alternatives to the Optical Gas Imaging Instrument Should Be Allowed for Leak Screening

As discussed in Comment XII, the current lack of trained and experienced infrared camera operators and GHG fugitive emissions survey companies required to complete the annual leak inspections necessitates a phased-in approach. Furthermore, limited camera technology options exist, severely limiting the options for compliance. INGAA recommends the acceptance of alternatives.

Leak screening and detection can be accomplished using a variety of lower cost tools and methods. The Proposed Rule prescribes an optical camera to identify leaks during the annual facility leak survey. INGAA recommends allowing alternatives to the optical camera for leak detection. Standard methods are available, including methane detectors, ultrasonic/acoustical instruments, soap solution, etc. In most applications, these methods have been used in practice for a longer period than the optical gas imaging camera technology and are equal to or better than infrared optical imaging camera technology for locating accessible leaking components.

INGAA requests that the Final Rule include all demonstrated technologies and alternatives that are used in practice. Limiting the technology choice to optical infrared cameras is unreasonably restrictive, and unintentionally implies favoritism or endorsement of a single technology by precluding proven, less expensive leak detection and measurement instruments and/or methods. It is also important to note that the optical infrared camera only indicates the presence of a leak. Therefore, the optical camera, Method 21, and soap solution perform the identical function of identifying leaks. The camera does provide the advantage of surveying difficult to access (e.g., elevated) components, as other methods require direct access to the component.

A rule that allows alternative methods, with consensus methods validated separate from the rule and industry practices used in the interim, provides the most expedient path to support rather than preclude innovation and technology advancement. Limiting instrumentation or prescribing hierarchy for monitoring and measurement introduces unnecessary restrictions which preclude knowledgeable professionals from implementing the “right” technical approach for leak monitoring.

It is INGAA’s understanding that the FLIR GasFindIR camera is currently the primary optical infrared camera technology manufactured in commercial quantities. With limited market competition, EPA has inappropriately endorsed a technology vendor and created a demand that will preserve or even raise the cost of this technology. Alternatives based on industry standard practices in the near-term and peer-reviewed, consensus (e.g., ASTM) methods in the long-term should be allowed.

In addition to substantial instrument cost, camera technology performance is susceptible to environmental factors. The camera is not intrinsically safe within an enclosed environment (e.g., compressor building) and typically requires a hot work permit to conduct a leak survey. The expertise required to operate the camera involves significant training and experience with imaging at similar industry sources, whereas other technologies and methods such as soap solution can be easily applied and observed by less-experienced personnel. EPA should not select and promote a single preferred technology when suitable and viable alternatives are available and used in practice.

EPA has funded field studies that have employed all of the recommended technologies and leak detection methodologies discussed in these comments. These “tools” provide the necessary flexibility to screen leaking components through use of accepted and practiced techniques that may be more suitable based on environmental conditions, available tools, and/or survey team experience level.

Similar to the October 2009 Final Rule, “industry practices” or consensus standard should be permissible. For example, the 2009 Final Rule references industry practices in many subparts, such as Subpart MM for Suppliers of Petroleum Products which indicates at §98.394(a)(1)(ii):

“(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.”

Since methods are not consistently available for leak surveys of natural gas systems, similar language should be added to Subpart W. EPA should allow emissions detection and measurement methods developed and relied on in practice, including use in EPA-sponsored projects and for emissions reported under the Natural Gas STAR program. INGAA recommends adding language in §98.234(a)(2) [currently reserved] to include the following:

"In addition to the optical gas imaging instrument, alternative technologies may be used to conduct annual leak detection of fugitive emissions in accordance with industry standard practices, consensus-based standards, or manufacturer recommendations. These include, but are not limited to, organic vapor analyzers, portable hydrocarbon gas detectors, ultrasonic leak meters, ultrasonic acoustic detectors, and soap solution."

As discussed in these comments, the optical gas imaging instrument has limitations that are best resolved through the inclusion of alternative technologies, practices, and standards.

Optical Gas Imaging Instrument Procedures and References to the AWP Should Be Revised

§98.234(a)(1) specifies the use of an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, Subpart A, § 60.18(i)(1) and (2) of the Alternative Work Practice (AWP) for monitoring equipment leaks. INGAA supports EPA's decision to limit and minimize the AWP requirements listed in §60.18. However, this AWP was not intended to address methane or GHG leaks and contains many provisions and requirements that are inappropriate or too restrictive for natural gas transmission and storage component leak screening.

For example, §60.18(i)(1) specifies the optical gas imaging instrument specifications. This section precludes the use of the commercially available Remote Methane Leak Detector (RMLDTM) because it does not provide an "image" of the potential leak as defined in (1)(i) or video records as defined in (1)(ii).

§60.18 (i)(2) provides a detailed procedure for daily instrument checks that was intended to address mixed hydrocarbon streams and varied flow rates from refinery processes. This process scenario is not applicable to natural gas transmission and storage sources. Natural gas composition is well defined, and is not subject to the significant composition variability considered under this section. Furthermore, the mass flow rate determination [paragraph (i)(2)(i)(B)] using monitoring frequency and mass fraction of detectable chemicals is also inappropriate for natural gas transmission and storage sources.

INGAA recommends that reference to §60.8(i)(2) be replaced with an alternative calibration approach that is more appropriate for application to natural gas sector sources for methane leak surveys. For example, flow could be modulated using a rotameter selected to provide a three-point check over a range of flows using a 100 percent methane standard. In addition, a calibration check could be completed using the available high volume sampler calibration standards per §98.234(d)(4) and this section should be cited under §98.234(a)(1). The calibration criteria under §98.234(d)(4) indicates the following:

"Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration."

The Proposed Rule referenced only certain sections of the AWP and eliminated the AWP leak practice procedure. INGAA recommends instrument operation in accordance with the manufacturer's recommendations or industry standard practices. In addition, the General Provisions under 40 CFR Part 60 Subpart A, Section 18, Paragraph (a) should be revised to include reference to leak screening under 40 CFR Part 98.

The Rule Should Include Provisions for Eliminating or Decreasing the Frequency of Leak Screening

The requirement for an annual survey is basically an arbitrary decision since data are not available to support the proposed frequency required for surveys of natural gas transmission and storage facilities. In addition, portions of the facility that are not in vibration or heat-cycle service may be amenable to much less frequent surveys. Thus, the Proposed Rule should include provisions for eliminating or decreasing the frequency of annual leak screening should data and/or EF advances meet accuracy needs and leak screening data indicate that intervals can be relaxed. Since data gathering for reporting will provide a significant influx of information on leaks from natural gas systems, fugitive leak detection should not be adopted in perpetuity. Annual leak surveys should be phased out over time as data are collected and assessed, alternatives such as improved equipment- or component-based emission factors are identified, and reasonable data quality and inventory accuracy objectives are met.

This could be implemented through text additions to the rule, or citations to procedures in the EF reference document discussed above that could be used to identify alternative approaches (e.g., population-based emission factors that preclude a leak survey and identification of facility systems (e.g., yard piping) that do not warrant annual surveys).

Response: Concerning the availability of equipment or trained operators, for certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F.

EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F.

EPA disagrees with the comment to allow reporters to choose methods for leak detection that are not specified in subpart W. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section L. EPA's analysis of leak detection methods is outlined in the April 2010 Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027), and in the April 2010 preamble Section II.E.

EPA disagrees that it has inappropriately endorsed a technology vendor. Today's final rule allows for the use of any vendor of optical gas imaging technologies that meet leak detection specifications of the Alternative Work Practice to Method 21, any other Method 21 leak detection technologies, infrared laser beam illuminated instruments, or acoustic leak detection instruments.

EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.
EPA disagrees with the commenter that instrument specifications in the Alternative Work Practice to Method 21 for 40 CFR part 60 are inappropriate for the natural gas sector. EPA 40 CFR part 60 regulations are also applicable to the natural gas processing sector, and today's final rule will continue to use these standards.

EPA disagrees with eliminating or decreasing the minimum annual leak detection survey to calculate emissions. Annual reports must be calculated and submitted each year. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble, Section II.H. EPA disagrees with the comment on how to update emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Concerning manufacturer's recommendations, please see the response to EPA-HQ-OAR-2009-0923-1042-27.

Comment Number: EPA-HQ-OAR-2009-0923-1168-7
Organization: Delmarva Power a PHI Company
Commenter: Wesley L. McNealy

Comment Excerpt Text:
Leak Survey Requirements

In addition to DPL's concerns that Subpart W's proposed leak survey requirements would be duplicative, EPA's proposal prompts other concerns. Specifically, Subpart W requires the use of optical scanning through the use of infrared cameras for leak detection purposes. Such equipment is costly ranging from $80,000.00 - $100,000.00 per camera. In light of the fact that most LDCs would require more than one camera for EPA's proposed leak detection requirements, LDCs would not only be forced to incur the cost of multiple cameras but would also incur Significant costs associated with employee training and maintenance. In contrast, PHMSA allows LDCs to utilize a full range of leak detection equipment and materials for each circumstance such as gas detection wands and leak detection solutions; DPL recommends that the EPA consider this option.

Response: EPA disagrees that the rule is duplicative of DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1171-4
Organization: Western Resource Advocates

Commenter: Robert Harris

Comment Excerpt Text:

In light of EPA partners' recommendations under the Natural Gas STAR Program, including for the use of ultrasound to detect valve leaks at production facilities,[135] EPA's pessimistic characterization of measures to detect and fix leaks at production facilities in this rulemaking, 75 Fed. Reg. 18608, 18623, appears contrary to the facts before the agency.

Estimating fugitive emissions of production facilities solely through population count and emission factors is unlikely to meaningfully aid operators in reducing GHG emissions and conserving hydrocarbons. Proposed section 98.233(r) would generically calculate fugitive emissions from production facilities using EPA's "default" estimates provided in proposed Table W-1. Entirely divorced from site-specific conditions, this calculation amounts to little more than a paperwork exercise. Instead, EPA should mandate annual leak detection at relevant onshore production source types listed in section 98.232(c) as a common-sense measure to help operators improve efficiency and reduce their GHG footprint.

Response: EPA disagrees with the comment to require leak detection for onshore production, as population emission factors result in reduced burden on industry while maintaining the necessary quality of data to inform policy. Please see the preamble Section II.F. EPA's analysis of the use of population emission factors is outlined in the Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027), and in the April 2010 preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1099-20
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:

Section 98.233.q requires a leak detection survey of connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines using an optical gas imaging instrument at compressor stations. The leak detection survey as proposed is time consuming and expensive. For a detail of issues on leak surveys please see above comment #2 under General Comments on Subpart W. If leak surveys are required, NMGC proposes that alternative methods of detecting leaks, such as the soap bottle, be allowed. They are more effective than infrared cameras and much less costly to employ.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-1099-8 and the preamble Section III.B.

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[135] PRO Fact Sheet No. 602 (Natural Gas STAR partner Texaco estimated that using ultrasound to identify valve leaks will generally pay for itself in less than a year).

Comment Number: EPA-HQ-OAR-2009-0923-1152-13
Organization: Consumer Energy Company
Commenter: Amy Kapuga

<u>Comment Excerpt Text:</u>
Allow Broader Range of Leak Detection Equipment for Leak Surveys at Underground Storage Facilities.

Similarly, EPA should not require the use of optical gas scanning equipment (infrared FLIR cameras) but should allow a broader range of effective leak detection equipment for leak surveys at underground storage facilities, as we argue elsewhere in these comments. Consumers appreciates the opportunity to comment. We look forward to working with you to make the reporting rule for natural gas utilities practical and effective. If you should have any questions, please call me at 517-788-2201.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1152-7
Organization: Consumer Energy Company
Commenter: Amy Kapuga

<u>Comment Excerpt Text:</u>
Allow Broader Range of Leak Detection Equipment---

To reduce costs and to improve results, Consumers urges EPA not to require the use of optical gas scanning equipment/ infrared cameras, and instead to allow the use of a full range of available leak detection equipment, allowing the operator to select the tool that is most effective for a given situation. The best way to do this may be to reference existing federal and state leak detection regulations and relevant portions of the industry standard guidance for leak surveys.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1151-74
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
(Preamble p 75) EPA is seeking comments on allowing the OVA/TVA to be used as another option to the optical imaging camera in this proposed rule.

API supports the use of OVA/TVA as an alternative option to the optical imaging camera. The leak detection requirements should also be consistent with existing leak detection and repair

(LDAR) regulations for onshore natural gas processing facilities to minimize additional burden required to collect data on these components. In addition, other alternatives should be allowed for leak detection. Limiting leak detection to the optical camera alone is too restrictive and will result in increased costs, as it will immediately create a shortage of qualified personnel due to the large number of entities required to perform this leak monitoring. Existing leak detection and repair (LDAR) programs using OVA's should explicitly be allowed for Subpart W. Additional accepted alternatives such as methane detectors, ultrasonic / acoustical methods, and soap solution are available, are already used in practice, and provide better or equivalent data in many cases. These methods should also be included in Section 98.234(a), and where standard methods are not readily available, industry standards or best practices should be allowed to accommodate those entities that cannot obtain the required equipment or manpower resources within the implementation timeline of this rule.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Concerning the availability of equipment or trained operators, for certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F. EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B.

Comment Number: EPA-HQ-OAR-2009-0923-1200-1
Organization: The Dow Chemical Company
Commenter: Robert Rouse

<u>Comment Excerpt Text:</u>
Dow Supports Allowing the OVA/TVA to be Used as Another Option to the Optical Imaging Camera in this Proposed Rule.

Dow operates a natural gas storage facility that is associated with a larger petrochemical facility. Therefore, proposed 98.233(q) requires the use of the methods described in proposed 98.234(a) to conduct an annual leak detection of fugitive emissions from the fugitive sources that are listed in the proposed rule. Rule 98.234(a)(1) requires the use of an optical gas imaging instrument in accordance with 40 CFR 60, subpart A sections 60.18(i)(1) and (2) Alternative work practice for monitoring equipment leaks.

Dow generally supports the use of an optical gas imaging instrument on a voluntary basis to detect leaks. However, as solicited by EPA on Page 18623 of the April 12, 2010 Federal Register proposal, Dow comments that allowing the use of an OVA/TVA to be used as another option should be included in the final rule for the following reasons:

1. A number of OVA/TVA instruments are readily available to our on-site fugitive emission monitoring personnel for annual monitoring and any desired follow-up monitoring.

2. The OVA/TVA instrument is capable of measuring a concentration of a leak, if detected, and Dow suggests that an instrument reading > 10,000 ppmv as methane should be treated as a leak for the purpose of this reporting rule.

3. The alternative work practice contains burdensome recordkeeping provisions (Reference 40 CFR 60.18(i)(4)(vi) where a video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. In addition, the video record must show that each regulated fugitive emission source can be identified. All video records must be kept for five years. Dow has previously expressed concerns with this burden of video records in our comments on the proposed rule to establish the Alternative Work Practice. In support of using an existing OVA/TVA instrument, the recordkeeping requirements are easier to implement and can be readily added to existing recordkeeping systems.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA has revised the rule and videos are not required. Please see response to comment EPA-HQ-OAR-2009-0923-1024-49.

Comment Number: EPA-HQ-OAR-2009-0923-1200-3
Organization: The Dow Chemical Company
Commenter: Robert Rouse

Comment Excerpt Text:
In addition, the Alternative Work Practice associated with the use of an optical gas imaging instrument requires that the regulated equipment also be monitored annually using a 40 CFR Part 60, Appendix A-7, Method 21 monitor at the leak definition required in an applicable subpart (Reference 40 CFR 60.18(h)(7)). Thus, the Alternative Work Practice technically requires annual monitoring with an OVA/TVA instrument. If EPA's intent in this proposed rule is to only require an annual survey of impacted sources with an optical gas imaging instrument, then the final rule should clearly reflect this intent with respect to the AWP.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA disagrees that subpart W annual leak detection surveys conducted with an optical gas imaging instrument must also be surveyed annually using Method 21, as this is not specified in subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1099-5
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
We assume EPA means infrared cameras which are very expensive to purchase at nearly $100,000 each, or that rent for upwards of $2,900 per week. Use of this camera on this number of stations in our system would be burdensome. New Mexico Gas Company rented one of these cameras last year to investigate their potential for identifying leaks when this rule was first proposed. Our company found that the results obtained are very dependent on the skill of the operator and how the camera is utilized plus the ambient conditions at the time of use. Our

experience with this equipment leads us to believe that traditional leak detection methods yield far better and consistent results.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1099-20.

Comment Number: EPA-HQ-OAR-2009-0923-1099-9
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Leak Detection Survey - Section 98.233.q requires a leak detection survey using an optical gas imaging instrument for sources listed in 98.232.e.7 and 98.232.i.1 (fugitive emissions at compressor stations and LDC's). The leak detection survey as proposed is time consuming and expensive. First, optical gas imaging instruments are not necessarily more effective than other methods of leak detection. In fact our tests show them to be vary [*sic*] susceptible to the operator and ambient condition changes. The preamble states (pg 18623) that optical gas imaging instruments are "able to scan hundreds of source types quickly". In our experience with infrared cameras this is not true. We had to stop at each piece of equipment individually to determine if there was a leak. For the camera to provide useful results one must be within 3ft of the source and have little to no wind. Second, despite EPA referencing methods for performing the leak survey in "Alternative work practice for monitoring equipment leaks", the results will vary widely since some parameters are not specifically defined.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1099-20.

Comment Number: EPA-HQ-OAR-2009-0923-1151-131
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
In addition, API requests that alternatives to the optical camera be allowed for leak detection from reciprocating compressor rod packing. Limiting leak detection to the optical camera alone is too restrictive and will result in increased costs, as it will immediately create a shortage of qualified personnel due to the large number of entities required to perform this leak monitoring. Accepted alternatives such as methane detectors, ultrasonic / acoustical methods, and soap solution are available, are already used in practice, and provide better or equivalent data in many cases. These methods should be included in Section 98.234(a), and where standard methods are not readily available, industry standards or best practices should be allowed to accommodate those entities that cannot obtain the required equipment or manpower resources within the implementation timeline of this rule.

There should also be additional metering and monitoring technologies made available for measuring the leaks from reciprocating compressor rod packing other than those currently identified in Section 98.234(c) and (d). There are a variety of monitoring devices that could be used to measure flow and emissions that would still meet the accuracy requirements of the proposed rule.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1151-74.
EPA has revised the rule to allow acoustic leak detection and quantification for compressor venting (through valve leakage). EPA's analysis of direct measurement methods is outlined in the Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027), and in the April 2010 preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1074-41
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.234(2):
This section should provide flexibility for leak detection monitoring through the use of any industry accepted practices, such as soap solution, instead of optical gas imaging instruments.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1079-1
Organization: Auburn Environmental
Commenter: Jim Riffle

<u>Comment Excerpt Text:</u>
I strongly agree with the Alternate Work Practice (AWP) outlining the usage of optical gas imaging equipment for leak detection. I have found that optical gas imaging greatly expedites leak detection surveys and allows hundreds of components per shift to be evaluated due to the elimination of the need for aerial man-lifts, fall protection, and ladders to reach elevated components. I have personally witnessed projects where large VOC emissions were completely overlooked by TVA, OVA, and bubble solutions methods as part of Leak Detection and Repair (LDAR) programs.

I strongly disagree with public comments that the usage of optical gas imaging cameras would be cost prohibitive. Many contractors are now offering leak detection service including optical gas imaging at very affordable prices that would eliminate the need for companies to purchase cameras and train individual in the proper usage. In addition, the amount of man-hours required to perform a leak detection survey is greatly reduced by implementing optical gas imaging as part of an LDAR program.

I believe that the usage of the optical gas imaging camera will reduce overall operating costs associated with leak detection, enhance safety, reduce fire risk, and promote Greenhouse Gas (GHG) reduction.

Response: EPA has reviewed and considered this comment. Regarding the comment on costs, please see the preamble Section III.B and the Economic Impact Analysis Section 5.

Comment Number: EPA-HQ-OAR-2009-0923-1065-10
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Measurement Methods

As noted above, we support EPA's proposal to scale back the number of sources that are required to conduct direct emissions measurement, and agree with the following technologies that EPA proposes to be used for direct measurement of those large sources: high volume samplers, meters (such as rotameters, turbine meters, hot wire anemometers, and others), and/or calibrated bags.

However, the Clean Energy Group is concerned with the cost burden associated with EPA's proposed technology for fugitive emissions detection (e.g., optical gas imaging instrument) for processing, transmission compression, underground storage, LNG storage, LNG import and export terminals, distribution, and above ground M&R and gate stations. The proposed rule requires that on an annual basis, the entire population of fugitive emissions sources proposed for reporting in this rule would be surveyed at least once. EPA should provide more flexibility by allowing the use of population emission factors for these facilities. Where population emission factors cannot be used, EPA should allow the use of Organic Vapor Analyzers (OVA) or Toxic Vapor Analyzers (TVA).

EPA states that the OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. EPA also notes that the OVA/TVA range is limited to the reach of an operator standing on the ground or fixed platform, thus excluding all emissions out of reach.

The Clean Energy Group disagrees with the proposed exclusion of OVA/TVA from use in the MRR. Industry has experience with and currently uses OVA/TVA to identify fugitive emissions. The industry finds OVA/TVA reliable and accurate. Given the fact that most equipment is at ground level, the majority of the fugitive emissions are always within reach. The Clean Energy Group recommends that EPA allow the use of OVA/TVA as another option to the optical imaging camera.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1082-16
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
The OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. In addition, the OVA/TVA range is limited to the reach of an operator standing on the ground or fixed platform, thus excluding all emissions out of reach. However, EPA is seeking comments on allowing the OVA/TVA to be used as another option to the optical imaging camera in this proposed rule. (page 75)

MidAmerican supports allowing the use of OVA/TVA. Both OVA/TVA and optical gas imaging instruments are capable of detecting leaks. There may be circumstances where one instrument is preferred over another. MidAmerican believes that providing companies' flexibility will produce the most accurate results.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1065-5
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
If leak surveys are required, allow the use of OVAs and TVAs.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1059-16
Organization: Montana-Dakota Utilities Co.
Commenter: Abbie Krebsbach

Comment Excerpt Text:
The leak detection requirements in §98.233(q) and §98.234(a) of the Subpart W Rule state that optical gas imaging instruments must be used to inspect for fugitive emissions annually at natural gas distribution meter and regulator stations. Optical imaging instruments are expensive and cost between $30,000 and $100,000 per device depending on what the EPA defines as an optical gas imaging instrument. Many instruments would need to be purchased and additional staff hired to conduct the required annual leak detection tests at all company meter and regulator stations. A quick estimate indicated that each MDU LDC may need to potentially purchase 50 instruments to conduct annual tests at all meter and regulator stations. Also, 20 to 30 additional employees per MDU LDC may be needed to conduct the annual testing. The optical gas imaging instruments and additional staffing would cost each MDU LDC approximately $6.5 million which is too high a cost for our customers to bear, especially since there is no benefit.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1059-17
Organization: Montana-Dakota Utilities Co.
Commenter: Abbie Krebsbach

Comment Excerpt Text:
The cost to implement leak detection in this manner is excessively burdensome to the industry and is not required by other programs. For instance, the DOT accepts soap solution leak detection and leak detection wands for conducting leak inspections and less than annual inspection frequencies. Again, MDU references AGA's comments which contain greater detail on the projected costs and labor, as well as additional information AGA provides regarding potential inaccuracy in measurement that occurs with optical imaging instruments due to wind and interference from nearby emitting sources. Even if the EPA were to only include city gate and district stations, MDU believes using optical imaging instruments for determining whether fugitive emissions are occurring would still be too costly and not more accurate than other approved leak detection methods.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1059-16.
Leak detection surveys as prescribed by DOT are not applicable to subpart W. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7.

Comment Number: EPA-HQ-OAR-2009-0923-1045-1
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

Comment Excerpt Text:
OGI is the Most Effective System of Emissions Detection for Petroleum and Natural Gas Systems

EPA has invited comment on allowing organic vapor analyzers ("OVA") or toxic vapor analyzers ("TVA") to be used as an alternative to OGI for detecting fugitive methane emissions. In our view, any leak detection program that does not incorporate OGI (or any comparably effective leak detection technology) will miss large numbers of significant leaks and result in reports that completely mischaracterize the magnitude and sources of GHG emissions.

The reason for this is quite simple: OVAs and TVAs (as well as the use of "soap bubble" techniques) are only capable of detecting leaks when applied by a skilled operator at extremely close range, along every square inch of a potentially leaking component. In our experience, these methods are impractical for large, complex facilities such as petroleum and natural gas systems, many of which have emitting components that cannot be safely or conveniently accessed by an OVA/TVA operator.

Since the time we built and placed our first OGI camera on the market, our customers have found thousands of substantial leaks in petroleum and natural gas systems that were completely overlooked by well-trained, well-equipped operators using OVA/TVA and soap bubble inspection techniques. OGI technology found leaks on components that were not tagged or were in areas of the facility considered “too difficult to monitor” under EPA’s VOC regulations. Inspectors equipped with OGI routinely find large leaks that are the largest contributors to a facility’s overall emissions. Examples of emission sources frequently identified with OGI but not included on the list of “tagged” components routinely inspected by OVA/TVA technology include weld connections, cracked welds, and open-ended lines.

The link below illustrates a common occurrence whenever OGI technology is demonstrated to a customer currently using TVAs. The video was collected with an OGI system in April of this year on an offshore oil platform. The video clearly demonstrates how a trained technician equipped with TVAs can easily miss a significant leak by placing the TVA probe in the wrong area or upwind from the precise location of the leak source. On the leak survey depicted in the video, two out of the three leaks identified by OGI were not detected with the company’s TVAs.

http://www.flir.com/thermography/americas/us/OGI/offshoreplatforms/

In addition to being the most technically effective technology for detecting fugitive emissions, OGI has other important benefits that EPA should consider. First, OGI enhances the safety of petroleum and natural gas facilities by avoiding the need for operators to use OVAs/TVAs in hazardous or inaccessible areas of facilities. In addition, OGI is capable of detecting potentially explosive leaks that would otherwise pose serious safety risks at facilities.

Second, OGI can and does yield considerable economic savings for facilities that use the technology to identify losses of natural gas. Unlike CO2, methane is a valuable product whose loss in the form of fugitive emissions is a significant cost for natural gas facilities. One study performed by Conoco Philips Canada at 9 gas plants and 13 compressor stations identified 144 leaking components that collectively accounted for 58.26 million cubic feet of methane per year, or $358,012.10 USD/year in lost product. The company estimated that 92% of the 144 fugitive sources are economical to repair, yielding savings with a net present value of $2,002,602.72 USD[136] FLIR Systems believes that such savings should be offset against the cost of OGI in the Economic Impact Analysis accompanying the proposed Subpart W, and considered in EPA’s ultimate analysis of leak detection methods.

The above benefits have been quickly recognized by companies that have adopted OGI technology. For example, an official from Shell has remarked:

[U]sing the camera for testing offers many advantages over more conventional technologies. The camera is a quick, non-contact measuring instrument that can also be used in hard-to-access locations. It also offers benefits in terms of safety and the environment - Rutger Zoutewelle,

[136] (PILOT STUDY: Optical Leak Detection & Measurement, 2006).

Shell Nederland Raffinaderij in Pernis (Rotterdam)[137].

Unfortunately, despite the clear benefits of OGI, our experience has shown that allowing facilities to choose between OGI and OVA/TVA techniques does not lead to sound regulatory results. In practice, many petrochemical and petroleum refineries have opted to avoid OGI entirely – perhaps because of cost concerns or a fear of incurring penalties for finding previously undiscovered leaks – and instead use the technologies that miss large leaks from untagged and uninspected components.

These components include equipment such as tanks (storage tank and condensate tank vents), compressors (the compressor units themselves, as well as the compressor blow-down vents), flares, and pressure relief valves. In addition, emissions from other components that are not usually tested in leak detection and repair (LDAR) programs, such as weld connections, cracked welds, and open-ended lines, can be the source of a facility's largest leaks and will go undetected because these areas are not on the list of tagged components.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Regarding the comment on costs, please see the preamble Section III.B and the Economic Impact Analysis Section 5.

Comment Number: EPA-HQ-OAR-2009-0923-1026-15
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
The proposed rule requires an annual leak detection of fugitive sources for each of the source categories listed in the proposed subpart. The prescribed methodology for performing these annual detection surveys requires the use of optical gas imaging equipment. Due to the combustible nature of natural gas, some locations within a facility may require equipment to be intrinsically safe. Much of the optical gas imaging equipment currently in use is not classified as intrinsically safe and therefore cannot be used within these areas for leak detection. Requiring the use of this equipment will further reduce the commercial availability of the necessary equipment, as facilities will need intrinsically safe equipment to complete the annual detection on all components at a facility. Dominion requests that the agency consider the use of other detection methodologies, such as organic vapor analyzers, which are already commonly used in the industry.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

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[137] (Lahaut, Tracing gas leaks - Maintenance and safety problems highlighted, Maintenance Magazine, 2008).

Comment Number: EPA-HQ-OAR-2009-0923-1024-29
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Fugitive Emissions Detection. The proposed Subpart W permits only one method of detecting fugitive emissions from leaking components, storage tanks, and reciprocating compressor rod packing cases: optical gas imaging used according to 40 C.F.R. SECTION 60.18(i)(1) and (2) of the "Alternative Work Practice." [138] EPA should not bind the petroleum and natural gas industry to a single fugitive emissions detection technology. The inclusion of only optical gas imaging would stifle innovation in emissions detection, and make the oil and gas industry captive to the relatively small collection of manufacturers and contractors that produce and operate gas imaging equipment. Indeed, Kinder Morgan and other members of our industry are concerned that the proposed requirement would create an immediate surge in demand for optical gas imaging services, which the industry may not be able to meet.

In addition, EPA's proposed optical imaging requirement would prevent members of our industry from taking advantage of potentially more efficient and effective technologies that are either close to being commercialized or could be developed in the future. For example, EPA mentions laser technology (presumably the infrared laser leak detector) in the preamble to the proposed rule, but does not appear to seriously consider this technique even though, as in optical gas imaging, it permits remote detection of methane emissions within an operator's line of sight.[139,140] It is reasonable to expect that consensus standards for these new methods will soon be developed, but only if EPA actually encourages the development of such standards by allowing detection technologies other than optical gas imaging. Accordingly, Kinder Morgan recommends that the proposed 40 C.F.R. SECTION 98.233(q) be modified to allow appropriate standard methods of detection to be used – including but not limited to optical gas imaging.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1024-7
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
EPA should allow the use of other standard methods for leak detection in addition to optical gas imaging such as organic vapor analyzers, portable hydrocarbon gas detectors, ultrasonic meters

[138] Proposed 40 C.F.R. SECTION 98.233(q).

[139] Proposed Subpart W, 75 Fed. Reg. 18,623.] Partners in EPA's Natural Gas STAR program have also reported the use of ultrasound techniques to detect gas escaping from valves and similar components.

[140] Natural Gas STAR, Partner Reported Opportunities (PRO) Fact Sheet No. 602.

and detectors and soap solution. Binding the petroleum and natural gas industry to a single detection technology will stifle innovation.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1018-48
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
CAPP believes the prescriptive nature of 98.234(a) is unnecessarily burdensome and has chosen a very specific instrument which is not widely used or accessible. There are a limited number of consultants that offer this form of leak detection services. CAPP recommends that the EPA allows other leak detection methods to be used for all source types listed in §98.233(p)(3)(i) and (q) in operation or on standby mode that occur during a reporting period.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1018-16
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
Pre-amble-page 75, "EPA is seeking comments on allowing the OVA/TVA to be used as another option to the optical imaging camera in this proposed rule." ·

- Since emission estimation from fugitive equipment leaks is based on identification of leaking components and the use of appropriate leaker emission factors, CAPP supports the flexibility to use OVA/TVA as another option to optical imaging cameras. If OVA/TVA were used, EPA would have to adopt a leak definition consistent with that used to derive the leaker emission factors (probably 10,000 ppm).

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. In addition, in today's final rule EPA specifies an instrument reading of 10,000 ppm or greater as a leak using Method 21 instruments. The Clearstone emission studies referenced in the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923); used 10,000 ppm or greater as a leak using Method 21 instruments.

Comment Number: EPA-HQ-OAR-2009-0923-1016-13
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:

Optical Scanning/ Infrared Camera is Costly and Not Effective for Small Leaks; Therefore It Should Not be Required

EPA explains in the preamble to the 2010 Proposal that "EPA proposes conducting fugitive emissions detection and then applying leaking component (or leak only) emissions factors for processing, transmission, underground storage, LNG storage, LNG import and export terminals, and LDC gate stations."[141] Proposed section 98.233(q) requires LDCs and other facilities subject to Subpart W to use the methods described in 98.234(a) to conduct an annual leak detection of fugitive emissions" from the relevant list of components in §98.232.[142] Section 98.234(a) in turn requires the use of an "optical gas imaging instrument" for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) Alternative work practice for monitoring equipment leaks." There is no definition of "optical gas imaging instrument" in proposed Subpart W. However, the referenced work practice in Part 60, defines the term in 40 C.F.R §60.18(g)(4) as:

"(4) Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye."

Section 60.18(i)(1) and (20, as referenced in Subpart W proposed section 98.234(a) further provides:

"i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section..."

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[141] 75 Fed. Reg. at 18622.

[142] 75 Fed. Reg. at 18642.

Although we are not entirely certain, we believe this means that the optical gas scanning equipment required to be used for Subpart W leak surveys refers to what is known as an infrared camera.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. In addition, the optical gas imaging instrument is defined in the Alternative Work Practice to Method 21, and requires no further definition in subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1016-19
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
Allow Broader Range of Leak Detection Equipment---

In the 2010 Proposal, EPA is apparently requiring the use of infrared (FLIR) cameras for the annual leak surveys under Subpart W. This costly option is not necessarily the best option. In fact, one of our member companies performed a leak survey using a FLIR camera recently to assess whether it might improve leak detection for purposes of a potential project for the EPA Natural Gas STAR program. First the LDC used normal, commonly used leak detection methods in use for purposes of complying with existing federal and state leak survey requirements. Then the LDC followed up with the FLIR camera to see if the camera could detect additional leaks that were missed by the traditional leak detection equipment. The results were disappointing. When used at a natural gas distribution city gate, the FLIR camera did not perform as EPA assumes in the 2010 Proposal – it could not scan hundreds of source types at the station quickly. The FLIR did not find any additional leaks. In fact, the FLIR camera did not even find the small leaks that the LDC had already located using normal leak detection methods – even when one of the field personnel pointed at the location of the leak so the person holding the camera could point the FLIR directly at that location. They still could not see the leak with the FLIR. It appears that the FLIR may be useful in some settings -- such as high pressure facilities where leaks tend to be larger when they occur – but it does not appear as useful for finding the small leaks in tight LDC facilities.

In addition, EPA proposes to prohibit the use of Organic Vapor Analyzers (OVA). We disagree with EPA's assumption about the accuracy of this equipment. Our members have demonstrated that OVAs are a proven technology for which extensive operating procedures and trained employees already exist.

Accordingly, to reduce costs and to improve results, AGA urges EPA not to require the use of optical gas scanning equipment/ infrared cameras, and instead to allow the use of a full range of available leak detection equipment, allowing the operator to select the tool that is most effective for a given situation. The best way to do this may be to reference existing federal and state leak detection regulations and relevant portions of the GPTC industry standard guidance for leak surveys.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA disagrees that optical gas imaging instruments are inferior to alternative leak detection methods. Please see EPA's analysis of the optical gas imaging instrument in EPA's preamble to the Alternative Work Practice to Method 21, and in docket EPA–HQ-OAR-2003-0199-0005.

Comment Number: EPA-HQ-OAR-2009-0923-1016-36
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
Allow Broader Range of Leak Detection Equipment for Leak Surveys at Underground Storage Facilities

Similarly, EPA should not require the use of optical gas scanning equipment (infrared FLIR cameras) but should allow a broader range of effective leak detection equipment for leak surveys at underground storage facilities, as we argue elsewhere in these comments.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1011-45
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Section 98.233(q) Leak detection and leaker emission factors

Currently, Section 98.233(q) requires surveying standard components (such as connectors and valves, as opposed to vented components) with an IR camera and then applying a "leaker" emission factor to the number of leaks found for each component type. It's clear that EPA's intent was to reduce labor costs in this area. However, this approach still requires a substantial amount of effort that does not provide a large improvement in the accuracy of the reported emissions. It would also distract from collecting accurate data from the vented components that make up the majority of non-combustion emissions.

The contribution of leakage from standard components averages about 20% of the total leakage at transmission compressor stations (Howard et al., 1999 – this was a joint study sponsored by

PRCI, GRI, and EPA)[143]. Because the proposed method uses an emission factor as opposed to a measurement, there will still be uncertainty in this method. The EPA Natural Gas Star program has previously developed emission factors for compressor stations based on the number of compressor units at the site (EPA, 2000)[144]. These factors include both standard and vented components but could easily be recalculated to assess only standard components.

Although the proposed method of using leak detection combined with leaker emission factors would be expected to give better results than applying a facility emission factor, this improvement only applies to approximately 20% of the total facility leak rate. Consequently, the improvement in the reporting accuracy for the entire facility is probably less than 5%, while the effort involved might require as much as 50% of the total leak survey effort.

Allowing a facility emission factor for standard components as an option to leak screening lets facilities focus on making measurements at the vented components that account for 80% of the total emissions. This full focus should improve the accuracy of the data collected from these key sources.

Should EPA still feel that leak surveys of standard components are essential, it would be better to allow more options than just the IR camera to conduct these surveys. Although these cameras are useful tools, screening with flame ionization detectors, catalytic oxidation/thermal conductivity detectors, and soap solutions have been proven to be effective (Howard et al., 1999; EPA, 2002; KSU, 2006) and should not be excluded.

It’s possible that EPA felt that the IR cameras would be the most cost effective approach, and for some companies, that may be true. However, other companies might want to have in-house personnel conduct leak screening with techniques that they already know how to use. Clearstone’s 2006 study (KSU, 2006)[145] notes that a 2 person crew with an IR camera can survey approximately 6,400 components per day. The PRCI study (p. A-1-14) found that experienced personnel could survey transmission station components using a combination of soap and catalytic oxidation/thermal conductivity detectors at a rate of 350 components per person per hour, or 5,600 components per two person crew per eight hour day. During this time study, the personnel found 99.6% of combined leaks found by using this method and a Foxboro TVA – 1,000, so these methods are clearly still effective.

Facilities that have access to IR cameras and trained personnel could apply the IR camera if they so desired. Other facilities without these resources could rely on past experience and conduct the leak screening on a flexible time schedule without necessarily acquiring more equipment or

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[143] Howard, T., R. Kantamaneni, and G. Jones, 1999. Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations. PR-246-9526. PRCI, 1515 Wilson Boulevard, Arlington, VA22209.

[144] EPA, 2000. Natural Gas STAR Default Value Analysis Project. 7th Annual Natural Gas STAR Implementation Workshop, October, 2000.

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

hiring contractors.

Contribution of Standard Components to Total Leakage

There may be an overemphasis on the importance of standard components at facilities due to Clearstone Engineering's studies at gas plants in 2002 and 2006. Although these studies were detailed and well executed, gas processing plants have a much larger ratio of standard components per compressor unit than is found at transmission compressor stations. For instance, in the PRCI study done at thirteen transmission compressor stations, the number of components per compressor unit was a little over 400. The Clearstone studies don't list a complete inventory of compressor units, but if there were twenty units at each site, the ratio of components to compressor units would be approximately 1,000, about two and one half times greater than at transmission sites. Additionally, standard components at processing plants may be subjected to greater heat and vibration in some areas than at transmission compressor stations.

The 2002 Clearstone study (EPA, 2002)[146] indicated that connectors and valves accounted for over 50% of the total leakage (Figure 10 of that study), whereas at transmission stations that number is more likely to be 20% (Howard et al, 1999). Additionally, the 2006 Clearstone study (KSU, 2006) indicates that connectors and valves were down to approximately 32% (Figure 13 of that study). Open ended lines contributed another 30%, but this category apparently includes compressor blow down valve leakage which would probably dominate the leakage.

It is understood that for the purposes of the proposed rule that different leaker emission factors have been developed for transmission as opposed to processing. However, the key point is that standard components in transmission don't contribute to the total leakage as much as the Clearstone studies might be interpreted to suggest.

Response: Please see response to comments EPA-HQ-OAR-2009-0923-0055-8 and EPA-HQ-OAR-2009-0923-0055-14.

Comment Number: EPA-HQ-OAR-2009-0923-0955-4
Organization: American Public Gas Association (APGA)
Commenter: Bert Kalisch

<u>Comment Excerpt Text:</u>
The Final Rule should allow other leak detection equipment for LDCs in addition to optical gas imaging equipment.

By operation of Section 98.233 (q), all LDC facilities identified by Section 98.232(i)(1) are required to be leak surveyed annually. Section 98.234(a)(1) requires that such surveys use an optical gas imaging instrument. APGA appreciates that EPA's intent is to allow LDC operators to use equipment that can detect and count leaking components from a distance and thus reduce

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

the burden of conducting these surveys. APGA supports allowing utilities to use this method, but does not support requiring its usage. EPA should allow LDCs to use the equipment which they currently use for leakage surveys and all of which are at least (and in many cases are much more) accurate than the optical imaging equipment that would be required by the Proposed Rule. In addition to optical gas imaging equipment, leakage surveying equipment used by gas distribution operators includes:

Flame-ionization Detector (FID)

Catalytic Combustion / Thermal Conductivity Combustible Gas Indicator (CGI)

Optical

Laser

APGA stresses that the cost of purchasing an optical gas imaging device or hiring a contractor to leak survey with such a device would be entirely unnecessary as an optical imaging device would provide no better results that the leak detection equipment listed above, at least one of which LDCs already own and use effectively. Moreover, optical imaging devices are much more costly than many of the leakage detection equipment listed above.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-0837-5
Organization: Canadian Gas Association
Commenter: Michael Cleland

<u>Comment Excerpt Text:</u>
We do not see how the requirement to limit leak detection technologies solely to optical gas imaging instruments can be justified, at least in the LDC context. This overly restrictive requirement is a disincentive for further innovation, and in the case of LDC's, requires additional costs and training that cannot be economically justified. As the Technical Support Document (TSD) (p. 25) notes, "traditional technologies like Toxic Vapor Analyzer (TVA) and Organic Vapor Analyzer (OVA) are appropriate for use in small facilities with few pieces of equipment". The TSD further notes that "the main disadvantage of an IR camera is that it involves substantial capital investment ... therefore, these cameras are most applicable in facilities with large number of equipment and multiple potential leak sources or when purchased at the corporate level, and then shared among the facilities."

While an LDC might "share" a single optical gas imaging device as the TSD notes, it is still questionable whether this would truly reduce costs once the need for specially trained staff and travel costs to survey geographically dispersed sites are factored in. In the Canadian context, an LDC's facilities can span significant areas within a province. On the other hand, company employees within each region can use existing, on-hand leak detection equipment such as OVA's to achieve the same objective of leak detection.

We therefore suggest that EPA remove the equipment specification related to leak detection, leaving the choice of technology to reporting companies to choose the monitoring method most appropriate to their operations.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1305-42
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
OVA/TVA Monitoring

EPA is seeking comments on allowing the OVA/TVA to be used as another option to the optical imaging camera in this proposed rule.

BP supports the use of OVA/TVA as an alternative option to the optical imaging camera – particularly where a current LDAR program is in place under Subpart KKK.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1306-10
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
Alternatives to the proposed methods for leak detection should be considered to provide more flexibility in meeting the requirements of the proposed rule

EPA should allow alternatives to the "optical gas imaging instrument" described in Sec. 98.234(a) for detecting fugitive emissions from each source category. Limiting the fugitive emissions leak detection method to one technology does not recognize the numerous tools that are already used by the industry to detect fugitive leaks and will potentially create shortages of instruments or trained technicians in the first year or two of the program. Restricting the types of leak detection that can be used does not allow for technology improvements that could be made to existing gas detectors and does not take into account the limited number of vendors that provide this product or its high cost. EPA indicates that contractors could be used to do this leak detection, and it is our understanding that a very limited number of contractors are available with optical gas imaging instruments. DTE Energy believes that EPA should provide maximum flexibility in the rule for allowing the use of existing or yet to be developed methods for fugitive leak detection. We support the use of IR Laser Detectors, Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) for fugitive leak detection.

Flexibility in evaluating fugitive leaks should also be provided for detecting leaks from inaccessible or out of reach sources, including situations where safe working conditions cannot be met by using an approved leak detection device or method. DTE Energy requests that EPA allow for the use of population emission factors or use of manufacturer's specification in these special situations.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1306-3
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
In addition, we are concerned about the lack of flexibility allowed for leak detection methods in the proposed rule. The remainder of this letter explains our concerns in more detail.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1306-6
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
Alternatives to the proposed methods for leak detection should be considered to provide more flexibility in meeting the requirements of the proposed rule

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-0132-4
Organization:
Commenter: Michael Webb

Comment Excerpt Text:
Locating Fugitive Emissions (§98.234 Monitoring and QA/QC requirements)

I propose that §98.234 (a) (2) be worded:

Method 21 approved methodologies or other monitoring techniques with a methane and/or CO_2 minimum sensitivity limits equal to or less than the lowest value given in Table 1 to Subpart A of Part 60 -Detection Sensitivity Levels (grams per hour) for the Optical Gas Imaging Instrument.

There are several methodologies current in use by the oil & gas and chemical industries that locate very small leaks (such as sonic testing, volumetric displacement, etc.). 40 CFR Part 98 would be stronger if it included all of these proven methods.

Allowing the use of other methods that are at least as sensitive as the Optical Gas Imaging Instrument will be “technology-forcing”. It will motivate companies to develop new equipment now and in the future that can detect low emissions of methane and/or CO_2.

For example, the Bacharach, Inc. Hi Flow® Sampler, referenced in Appendix K of the Background Technical Support Document for Subpart W, lists a minimum sensitivity level of 0.05 scf/min. This is approximately 57 grams/hr of methane. Therefore, the Hi Flow® Sampler might be useful for monitoring as well as quantifying leaks.

In the early 1990’s, I developed an experimental quantification system, the High Volume Collection System (HVCS), which was tested by the EPA both in the laboratory and in the field in 1994. EPA reported on the success of the HVCS in Document EPA-600/R-95-167, Evaluation of the High Volume Collection System (HVCS) for Quantifying Fugitive Organic Vapor Leaks.

A consumer version of the HVCS will be available later this year. It will locate and quantify both carbon dioxide and hydrocarbon fugitive emissions. The minimum detection limits for methane and CO_2 will be less than 1 gram/hr. The new version will weigh 3 pounds, will be fully automatic, and can be operated by anyone after a short training session.

As written, §98.234 (a) will prohibit the use of this and other new technologies. I recommend that §98.234 (b) include language that will allow new technologies to be used.

Response: EPA has revised today’s final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-0132-2
Organization:
Commenter: Michael Webb

Comment Excerpt Text:
In §98.234 (a) (2), allow the use of other techniques for locating fugitive leaks such as: Method 21 approved methodologies or other monitoring techniques with a methane and/or CO_2 minimum sensitivity limits equal to or less than the lowest value given in Table 1 to Subpart A of Part 60 -Detection Sensitivity Levels (grams per hour) for the Optical Gas Imaging Instrument.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-0050-3
Organization: Southwest Gas Corporation
Commenter: Jim Wunderlin

Comment Excerpt Text:
Costly and Ineffective Technology

In this Proposed Rule, Southwest is concerned that EPA has not appropriately considered the costs associated with gathering proposed information, let alone considered whether or not the technology and/or information on which estimated emission rates is based is anywhere near reasonably accurate.

Technology that is proposed to be used, such as IR laser detector instruments, Toxic Vapor Analyzers (TVA) or Organic Vapor Analyzers (OVA) may have applicability in the future, but they cost approximately $80,000 each. Southwest estimates that it would have to purchase at least 25 of them in order to complete leak surveys within the two month time period envisioned by the new rule. Even if there were enough instruments manufactured in time to comply with the initial reporting deadline, it is unlikely that they could be deployed in the field in any reasonable time frame to survey and collect information on literally thousands of possible, but unlikely, emission sources.

In addition, Southwest's experience with these instruments is that while the technology works for large leaks, Southwest employees had to identify smaller leaks by traditional methods, such as a soap solution, before the instrument operator could recognize the leak through the instrument viewer. These instruments also do nothing to quantify any leakage found

Response: EPA disagrees with the comment on costs. Please see response to comments EPA-HQ-OAR-2009-0923-1020-6 and EPA-HQ-OAR-2009-0923-0049-7, and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA disagrees that optical gas imaging instruments are inferior to alternative leak detection methods. Please see EPA's analysis of the optical gas imaging instrument in EPA's preamble to the Alternative Work Practice to Method 21, and in docket EPA–HQ-OAR-2003-0199-0005.

Comment Number: EPA-HQ-OAR-2009-0923-1020-3
Organization: Southwest Gas Corporation
Commenter: James F. Wunderlin

Comment Excerpt Text:
Costly Ineffective Technology

Southwest highly recommends that the regulations allow the use of industry standard leak detection methods that have been demonstrated to be accurate, highly effective and efficient over the past decades.

Optical scanning technology that is proposed to be used may have applicability in the future, but they cost approximately $80,000 each and Southwest alone would have to purchase 25 of them in order to complete the leak survey within the two month time period envisioned by the new rule. Even if there were enough instruments manufactured in time to comply with the initial reporting deadline, it is unlikely that they could be deployed in the field in any reasonable time frame to survey and collect information on literally thousands of possible emission sources.

In addition, Southwest's experience with these instruments is that while the technology works for large leaks, Southwest employees had to identify smaller leaks with a soap solution before the instrument operator could recognize the leak through the instrument viewer. These instruments also do nothing in terms of volume released or even atmospheric concentration to quantify any leakage found.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-0050-3.

Comment Number: EPA-HQ-OAR-2009-0923-0053 -6
Organization: Cardinal Engineering, Inc.
Commenter: Kristine D. Baranski

Comment Excerpt Text:
Additionally, more flexibility regarding the integration with existing leak detection and repair (LDAR) programs would be appreciated. Most facilities currently subject to LDAR regulations utilize OVA methods. Please consider allowing a combination of methods such as OVA/TVA for components that are already being monitored through these methods and optical gas imaging for other components.

Please consider allowing multiple alternate methods such as a "bubble test" method . This method would be much more cost-effective and provide the same qualitative information as compared to the optical gas imaging method.

Please consider allowing facilities to use alternate methods (other than optical gas imaging) in the event that the facilities are capable of monitoring all components (including components that may be considered "difficult to monitor" and are currently not being monitored as part of the existing facility LDAR program). When faced with the high cost of optical gas imaging, facilities may prefer to erect scaffolding or use fall protection harnesses or otherwise safely access "difficult to monitor" components. The added benefit of facilities choosing this option is that while personnel are accessing the component, some leaks may be repaired during the inspection process.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1305-31
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.234(b) Monitoring and QA/QC requirements

Subpart W Section 98.234(b) does not reference Section 98.3(i). Do the calibration and accuracy requirements in Subpart A - General Provisions Section 98.3(i) apply to Subpart W; including but not limited to the 5% accuracy and delay of calibrations until the next scheduled shutdown if a shutdown is needed to conduct the calibration? (The monitoring and QA/QC requirements in other subparts such as Subpart C - Combustion Section 98.34(b) and Subpart Y - Petroleum Refineries Section 98.254(b) reference Section 98.3(i).)

Section 98.234(b) Monitoring and QA/QC requirements

Applicability of Section 98.234(b) - Paragraph 98.234(b) provides the monitoring and QA/QC requirements for flow meters, composition analyzers and pressure gauges. For monitoring methods in Section 98.233 for emissions sources where EPA specifies in Table W-4 of the preamble (75 FR 18619) the monitoring method is direct measurement, Section 98.234(b) is referenced. For example the flow monitoring method for transmission tanks, centrifugal compressor wet seal degassing vents, and reciprocating compressor rod packing vents in Section Section 98.233(k)(2)(i), 98.233(o)(1) and 98.233(p)(2)(ii), respectively, all reference Section 98.234(b). Conversely, the flow or volume value used to calculate emissions for gas well venting during conventional well completions and workovers, well testing venting and flaring, and associated gas venting and flaring in Section 98.233(h), 98.233(l) and 98.233(m), respectively, do not reference Section 98.234(b). Thus, BP interprets Section 98.233(h), 98.233(l) and 98.233(m) to mean that the flowrate or volume values can be determined from flow meters that do not meet Section 98.234(b), engineering estimates or company records. EPA should confirm that the monitoring and QA/QC requirements in Section 98.234(b) do not apply to flow rate, pressure, and composition values when Section 98.234(b) is not specifically referenced in Section 98.233(a) through (z).

Response: Subpart A, and its instrument calibration procedures, applies to subpart W unless otherwise specified in subpart W. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section L. EPA has revised today's final rule Section 98.234(b) to clarify this. EPA has proposed amendments to subpart A calibration requirements, please see the MRR proposal August 2010.

Comment Number: EPA-HQ-OAR-2009-0923-1151-57
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.234(b) Monitoring and QA/QC requirements. Subpart W Section 98.234(b) does not reference Section 98.3(i). Do the calibration and accuracy requirements in Subpart A - General Provisions Section 98.3(i) apply to Subpart W; including but not limited to the 5% accuracy and delay of calibrations until the next scheduled shutdown if a shutdown is needed to conduct the calibration? (The monitoring and QA/QC requirements in other subparts such as Subpart C - Combustion Section 98.34(b) and Subpart Y - Petroleum Refineries Section 98.254(b) reference Section 98.3(i).) API interprets Section 98.234(b) to mean that Section 98.3(i) does not apply to Subpart W. If this interpretation is correct, API recommends EPA add the requirements in Section 98.3(i)(5) and (6) regarding previous calibrations that are still active and deferring calibrations to the next scheduled shutdown if a shutdown is needed to conduct the calibration into Subpart W Section 98.234(b).

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1305-31.

Comment Number: EPA-HQ-OAR-2009-0923-1151-58
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.234(b) Monitoring and QA/QC requirements. Applicability of Section 98.234(b) - Paragraph 98.234(b) provides the monitoring and QA/QC requirements for flow meters, composition analyzers and pressure gauges. For monitoring methods in Section 98.233 for emission sources where EPA specifies in Table W-4 of the preamble (75 FR 18619) the monitoring method is direct measurement, Section 98.234(b) is referenced. For example the flow monitoring method for transmission tanks, centrifugal compressor wet seal degassing vents, and reciprocating compressor rod packing vents in Section 98.233(k)(2)(i), 98.233(o)(1) and 98.233(p)(2)(ii), respectively, all reference Section 98.234(b). Conversely, the flow or volume value used to calculate emissions for gas well venting during conventional well completions and workovers, well testing venting and flaring, and associated gas venting and flaring in Section 98.233(h), 98.233(l) and 98.233(m), respectively, do not reference Section 98.234(b). Thus, API interprets Section Section 98.233(h), 98.233(l) and 98.233(m) to mean that the flowrate or volume values can be determined from flow meters that do not meet Section 98.234(b), engineering estimates or company records. API requests confirmation from EPA that the monitoring and QA/QC requirements in Section 98.234(b) do not apply to flow rate, pressure, and composition values when Section 98.234(b) is not specifically referenced in Section 98.233(a) through (z).

Response: The monitoring and QA/QC requirements detailed in Section 98.234(b) apply to all monitoring requirements in the rule, unless otherwise specified in subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1018-49
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
98.234 (b):
CAPP does not support the requirement for the re-calibration of ALL meters, analyzers and pressure gauges annually. Although CAPP agrees that calibration is necessary, the frequency of calibration should be based on manufacturers' recommendations. Scheduling of required calibrations should be left to the operator, since coordination with plant shutdowns might be required.

Response: All aspects of Subpart A, including instrument calibration procedures, apply to subpart W unless otherwise specified in subpart W. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section L EPA has revised today's final rule Section 98.234(b) to clarify this.

Comment Number: EPA-HQ-OAR-2009-0923-0847-10
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

<u>Comment Excerpt Text:</u>
Page 18645, §98.234. Monitoring and QC/QA requirements. paragraph (b): This requires all flow meters to use methods and calibration practices published by consensus organizations (e.g. ANSI and API). It further states that if a consensus based standard is not available, the manufacture's instructions must be used to calibrate a meter. This regulation may conflict with the recently approved MMS regulations in 30 CFR 250, Subpart K. In Subpart K, MMS requires operators to calibrate flare meters per the manufacture's recommendation or at least once per year, whichever is shorter. ANSI, API, etc. recommendations could require a shorter, or allow a longer, calibration frequency than Subpart K. Also, each time a consensus organization revises a recommended standard, conflicts with Subpart K requirements would need to be assessed. We recommend adding an additional sentence to paragraph (b) that would require offshore Outer Continental Shelf operators to install, maintain and calibrate flare/vent meters in accordance with 30 CFR 250, Subpart K.

We did not see any mention of flare/vent meter accuracy requirements in this proposed rule. By adding the above recommended sentence to §98.234(b), however, the accuracy and calibration requirements for meters installed on facilities in federal waters would be consistent with MMS requirements (30 CFR 250, Subpart K requires 5% accuracy).

Response: Regarding offshore production methodologies under subpart W, please see response to comment EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1156-23
Organization: Laclede Gas Company
Commenter: Steve Donatiello

<u>Comment Excerpt Text:</u>

Monitoring and QA/QC requirements at 40 CFR 98.234:

As stated in comment number 2 above, Laclede suggests that programs currently in place at LDCs to minimize the leakage of natural gas already provide strict, functional regulation in this area, and we recommend EPA abandon this course altogether. If EPA does proceed with requiring the counting of LDC components and annual leak surveys, EPA should ensure that subpart W expressly recognizes and accepts the use of all standard leak detection methods, technologies, and instruments approved now or in the future by PHMSA/DOT pipeline safety regulations for LDCs to identify leaks at above and below ground M&R stations, valves, compressor stations, wellheads, etc. The proposed rule is far too prescriptive with respect to the leak detection methods and equipment allowed, and seems to indicate insufficient understanding on EPA's part of the wide array of cost effective techniques at the natural gas distribution industry's disposal for locating and identifying leaks.

Response: EPA disagrees that the rule is duplicative of DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1306-12
Organization: DTE Energy
Commenter: Gregory L. Ryan

<u>Comment Excerpt Text:</u>
The proposed rule requires significant additional effort to log and report leaks beyond current requirements for detecting and fixing leaks on distribution systems and does not recognize that existing programs already minimize fugitive emissions from LDCs

Current regulations promulgated by the Department of Transportation (DOT) Pipeline and Hazardous Substances Administration (PHMSA) under Title 49 of the U.S. Code of Federal Regulations (CFR) and the Michigan Gas Safety Standards require utilities to perform leakage surveys on distribution systems and to follow up with leak repair on a schedule that is appropriate to the potential hazard of the leak to the public or to buildings. The implementation of this existing compliance program continually identifies and reduces emissions of GHGs from natural gas distribution systems.

In addition, a final order from the Michigan Public Service Commission (MPSC) to MichCon requires MichCon to prepare and submit a long term plan to significantly reduce the amount of cast iron main in MichCon's distribution system. The MPSC order, dated June 3, 2010, was part of a response to a rate case filing. Since cast iron natural gas piping has the highest emission factor for leaks among the various gas main construction materials, this order will have the effect of significantly reducing fugitive emissions of GHGs from MichCon's distribution system.

DTE Energy is concerned that the leak detection requirements for distribution systems under proposed Subpart W will add significant additional regulatory burden to a leak detection program that is already successful in identifying and fixing leaks. The proposed rule would require that all leaks detected will be recorded into a centralized system to be able to be reported to EPA. If optical imaging is used as the detection method, then the imaging video will be used as the record and identified leaks will be input directly into a database by the technician reviewing the camera footage. Technicians will require training to comply with EPA rules and in properly citing and reporting all leaks detected and/or repaired. DTE Energy does not currently employ such a system for leak detection and repair and would require significant time to adjust to such a procedure. If a rule is finalized in late 2010, only a few months will be available to implement the full procedure for performing inspections and documenting leaks identified by current procedures.

Response: EPA disagrees that the rule is duplicative of DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA has revised the rule and videos are not required. Please see response to comment EPA-HQ-OAR-2009-0923-1024-49.

Comment Number: EPA-HQ-OAR-2009-0923-1168-4
Organization: Delmarva Power a PHI Company
Commenter: Wesley L. McNealy

<u>Comment Excerpt Text:</u>
Furthermore, LNG storage facilities, under the US Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) are required to have leak and flammable gas detection systems. The PHMSA also mandates the monitoring of such systems and the repair of any leaking component or equipment. Also, LNG storage facilities typically vaporize fewer than 15 times annually during times of cold-weather peak gas demand. Such infrequent operations limit the probability and amount of fugitive emissions.

Response: EPA disagrees that the rule is duplicative of DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA disagrees with the comment on LNG facilities, and is including the LNG facilities in today's final rule. Please see the response to comment EPA-HQ-OAR-2009-0923-1025-1.

Comment Number: EPA-HQ-OAR-2009-0923-1065-9
Organization: The Clean Energy Group
Commenter: Michael Bradley

<u>Comment Excerpt Text:</u>
EPA's proposed rule would require natural gas LDCs to report fugitive emissions from the following sources: 1) above grade M&R and gate stations, 2) below grade M&R stations and vaults, 3) pipeline mains, and 4) service lines. The Clean Energy Group generally agrees with the sources identified by EPA for inclusion in the emission reporting program. However, the proposed rule provides no differentiation regarding the size, pressure, or purpose of above grade

M&R stations, so it is unclear which stations should be surveyed. The Clean Energy Group contends that emission reporting from these sources should be based on physical attributes such as size, pressure, or capacity, and that customer meters should not be included, with the possible exception of high capacity industrial meters, as this would make the process unmanageable due to the sheer number of customer meters.

The Clean Energy Group also finds that the requirement to annually survey M&R stations using an optical gas imaging instrument (i.e., camera) is unreasonable. It is unclear what benefit if any this technology provides relative to other methods more widely used by the industry to detect leaking equipment that are far more cost effective. Furthermore, most LDCs do not own these cameras and have no experience using them. As a result, companies would have to purchase these cameras, develop procedures and train staff to conduct these annual surveys and/or pay outside firms to conduct the surveys.

The Clean Energy Group believes the costs associated with this requirement renders it infeasible, as detailed below, and recommends that EPA allow the use of population emission factors to estimate the emissions from this source, or to allow leak surveys to be conducted less frequently – perhaps in alignment with current leak survey requirements specified by 49 CFR 192.723 Distribution systems: Leakage surveys.

Also, many LDCs operate a large number of small to very small distribution sub-systems in rural and remote areas in addition to large integrated distribution sub-systems in metropolitan areas. The costs for special leak surveys of these small, remote sub-systems are extremely high relative to the benefits of conducting them. If the use of population emission factors to report emissions from above-ground M&R stations is not allowed, the Clean Energy Group suggests that distribution facilities be redefined to exclude small, remote sub-systems in order to reduce reporting costs. Alternatively, the rule should include language that addresses the very high cost of special surveys for small, remote sub-systems.

Response: Today's final rule clarifies that only aboveground M&R city gate stations at custody transfer require leak detection. Please see the preamble Section II.F. EPA disagrees with the comment on DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1009-3
Organization: Xcel Energy Inc.
Commenter: Eldon Lindt

<u>Comment Excerpt Text:</u>
The proposed rule will place limitations on the leak survey technology used for annual leak surveys in city gate stations, metering and regulating (M&R) stations, valve sets, processing plants, storage fields and compressor stations. The proposed technology may not be the best or

most effective equipment for a particular situation. The proposed requirements also will require the LDCs to perform additional leak surveys, above those required by DOT Code. Performing these annual leak detection surveys using only the specified technology would likely overwhelm the market for such equipment and strain company resources since LDC's could be performing leak surveys on millions of stations. Xcel Energy supports allowing LDCs to use any leak detection equipment accepted by current industrial standards and/or practices. At the very least, use of Best Available Monitoring Methods (BAMM) should be allowed for the first reporting year.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Concerning the availability of equipment, for certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-0049-10
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Fourth, EPA should delete the requirement to conduct annual leak surveys at city gates and above ground M&R stations and the requirement to use infrared cameras or other types of optical gas scanning equipment. This duplicates existing leak survey requirements imposed at the federal and state level by DOT PHMSA and state utility commissions. In addition, leak surveys are unnecessary for GHG estimation purposes if EPA uses a facility level – rather than a component level - emission factor for city gates and M&R stations.

Response: Today's final rule clarifies that only above ground M&R city gate stations at custody transfer require leak detection. Please see the preamble Section II.F. EPA disagrees with the comment on DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Regarding the comment on facility level emission factors for M&R stations, please see response to comment EPA-HQ-OAR-2009-0923-1065-4.

Comment Number: EPA-HQ-OAR-2009-0923-0049-5
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Proposed Leak Surveys with Optical Scanning Are Not Necessary or Useful; They Duplicate Current Federal/ State Requirements

There is also no need for the annual leak surveys called for under Subpart W. EPA proposed these leak surveys in order to identify leaking components in city gate stations and above ground M&R stations. The proposed rule then would require LDCs to apply special emission factors for “leaking” components to calculate fugitive methane emissions. There are several problems with this proposal. First, infrared cameras are often not the best choice for locating leaks in distribution facilities. Second, infrared cameras are far more expensive than other reliable, effective leak detection methods. They cost between $80,000 and $100,000 each, compared to other options that cost as little as a few hundred dollars each. Third, federal and state agencies with many years of experience and expertise already require LDCs to perform regular leak surveys. EPA’s proposal would duplicate and potentially conflict with those federal and state leak detection requirements.

Response: EPA disagrees with the comment on DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. EPA disagrees that optical gas imaging instruments are less useful than alternative leak detection methods. Please see EPA’s analysis of the optical gas imaging instrument in EPA’s preamble to the Alternative Work Practice to Method 21, and in docket EPA–HQ-OAR-2003-0199-0005. EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today’s final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-0049-6
Organization: American Gas Association
Commenter: Pamela Lacey

<u>Comment Excerpt Text:</u>
DOT’s Pipeline and Hazardous Substance Safety Administration PHMSA already requires utilities to conduct leak surveys of gas distribution systems:

1. Once per year in business districts annually and

2. Once every 5 years outside business districts.

The PHMSA natural gas pipeline safety rules direct LDCs to use any effective “leak detector equipment.” See 49 C.F.R. §192.723. This rule allows LDCs to use the best, most effective equipment for the particular situation, choosing from the full range of available options, such as soap solution, gas detection wands, and various types of optical scanning equipment. This approach is less burdensome and frankly more effective than EPA’s duplicative proposal to require the use of optical scanning equipment – which we believe refers to infrared cameras. Our members have conducted field tests recently to compare the effectiveness of infrared cameras and other types of leak detection. They found infrared cameras (the most expensive of these options) can be useful for some purposes, but the cameras often fail to detect leaks in natural gas distribution facilities even after the operator has already located the leaks using less costly, normal methods for leak detection – such as soap solution and leak detection wands.

In addition, while some states adopt the PHMSA leak detection requirements by reference, many state public utility commissions (PUCs) impose more stringent standards for leak survey frequency and/or specify a range of acceptable, alternative leak detection methods. Some states require LDCs to conduct annual leak surveys of all distribution facilities regardless of where they are located, whereas PHMSA allows less frequent surveys for facilities located outside business districts.

Finally, there is no need to apply emission factors for "leaking" components to arrive at an estimate of methane emissions from city gate stations and above ground M&R stations. Subpart W proposes to apply a facility-level emission factor to below ground M&R stations. EPA has provided no reason for not using a similar approach for above ground M&R stations and city gates. This would eliminate the need to visit hundreds of thousands of industrial and commercial customer meters and regulators – or millions of residential meter & regulator sets – to count specific types of components (such as couplings and valves) or to perform duplicative leak detection using scarce and expensive infrared cameras.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-0049-5. Regarding the comment on facility level emission factors for M&R stations, please see response to comment EPA-HQ-OAR-2009-0923-1065-4. EPA's analysis of using population emission factors for below ground M&R stations is in the April 2010 preamble Section II.E. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18

Comment Number: EPA-HQ-OAR-2009-0923-0050-1
Organization: Southwest Gas Corporation
Commenter: Jim Wunderlin

<u>Comment Excerpt Text:</u>
PHMSA's regulations, which are found in Title 49 Code of Federal Regulations (49 CFR) Parts 192 and 193, establish the minimum requirements that all pipeline operators must meet. Notably, the leak survey provisions of 49 CFR §§192.721 and 192.723 and the gas and fire detection requirements of 49 CFR Part 193 apply. It is Southwest's opinion that EPA apparently has not considered the above referenced rigorous pipeline safety regulations under which both interstate and intrastate pipelines operate with regard to leak detection.[147] In so doing EPA appears to be ignoring the records of stringent leak survey and repair procedures that have been used by gas transmission, distribution and LNG operators for over 50 years, and for over 30 years as required by federal and state pipeline safety regulations, all of which demonstrate that gas pipelines use pipeline components that contain their product very well

Response: EPA disagrees with the comment on DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7.

[147] For an example of state regulations, see Arizona Administrative Code, Section R 14-5-202(R).

Comment Number: EPA-HQ-OAR-2009-0923-1206-53
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
We request that a minimum component size for leak survey should be defined (i.e., line size). We suggests [*sic*] that components associated with line size or tubing less than 2-inch diameter should be excluded consistent with other regulations for leak detection and repair programs. Other alternatives in addition to optical imaging cameras should be allowed for leak detection. Limiting leak detection to the optical camera alone is too restrictive and would result in increased costs and it would immediately create a shortage of qualified personnel due to the large number of entities required to perform this leak monitoring. Accepted alternatives such as methane detectors, ultrasonic / acoustical methods, and soap solution are available, are already used in practice, and provide better or equivalent data in many cases. These methods should be included in §98.234(a), and where standard methods are not readily available, industry standards or best practices should be allowed to accommodate those entities that cannot obtain the required equipment or manpower resources within the implementation timeline of this rule.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Today's final rule specifies that tubing systems equal to or less than one half inch in diameter needn't be monitored for equipment leaks or reported under subpart W. Please see the response to comment EPA-HQ OAR-2009-0923-1152-8.

Comment Number: EPA-HQ-OAR-2009-0923-1151-43
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(q)(2) Leak Detection and Leaker Emission Factors (Onshore Natural Gas Processing Facilities. API requests that a minimum component size for leak survey should be defined. API suggests that components associated with line size or tubing less than 2-inch diameter should be excluded because these components are expected to have minimal leakage while significantly adding to the burden on industry for collection of data associated with this smallest category of components. The leak detection and component count requirements should also be consistent with existing leak detection and repair (LDAR) regulations for onshore natural gas processing facilities to minimize additional burden required to collect data on these components. In addition, other alternatives to optical imaging cameras should be allowed for leak detection. Limiting leak detection to the optical camera alone is too restrictive and would result in increased costs, as it would immediately create a shortage of qualified personnel due to the large number of entities required to perform this leak monitoring. Accepted alternatives such as methane detectors, ultrasonic / acoustical methods, and soap solution are available, are already

used in practice, and provide better or equivalent data in many cases. These methods should be included in Section 98.234(a), and where standard methods are not readily available, industry standards or best practices should be allowed to accommodate those entities that cannot obtain the required equipment or manpower resources within the implementation timeline of this rule.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Today's final rule specifies that tubing systems equal to or less than one half inch in diameter needn't be monitored for equipment leaks or reported under subpart W. Please see the response to comment EPA-HQ-OAR-2009-0923-1152-8.

Comment Number: EPA-HQ-OAR-2009-0923-1039-16
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Vent Measurement – Subpart W Should Allow Continuous Direct Measurement of Manifolded Vent Lines as an Alternative that Operators Can Elect to Employ

The previous sections discuss emission estimation methods for vented sources and INGAA comments on these vented emissions. In addition to those source-specific comments, the Proposed Rule should allow continuous direct vent flowrate measurement as an approved alternative, with that option selected at the discretion of the owner/operator. In general, INGAA recommends that "direct measurement" alternatives should not be precluded from Subpart W, and flexibility should be provided to apply demonstrated methods with similar or higher accuracy. Specifically, INGAA recommends that continuous direct measurement of vented lines, including manifolded lines, should be allowed as an operator option under Subpart W. In this case, the annual vented emissions would be measured and reported, and the report would identify the sources addressed by the vent measurement. For a transmission compressor station, this could include more than one of the seven sources (or more than one reciprocating compressor operating mode).

Some facilities are equipped with existing manifolded vent lines, but this type of configuration is not prevalent in the natural gas transmission and storage segments. At other facilities, vent access issues discussed above may increase interest in developing alternative vent line configurations. In the long term, issues with conducting annual measurements may result in some facilities migrating to continuous direct measurement. A direct measurement approach for manifolded lines would provide accurate annual data rather than projection of a one-time snapshot to annual emissions. However, the Proposed Rule precludes this option. INGAA recommends rule revisions to allow continuous direct measurement as an optional approach that the owner/operator may elect to use. This alternative is consistent with data quality and inventory accuracy objectives. In addition, the alternative will provide near-term options while providing the flexibility to adapt and implement new technology.

For manifolded vent lines, the vent measurement would co-mingle streams from multiple sources (e.g., multiple compressors), such that mode-based or source-specific emissions (e.g., compressor vent versus compressor unit blowdown) would not be available. However, the tradeoff for lack of this particular information for a facility is a more accurate annual report of cumulative facility vented gas emissions. It appears that mode-based and source-specific information is of interest to help inform policy objectives, and EPA may be concerned by aggregation resulting from manifolded lines. However, the vast majority of existing facilities will not employ continuous vent measurement, so source-specific data will be broadly available from those facilities. Complementing such information with total vent volume measurements at other facilities should actually provide EPA with more compelling and complete information on facility GHG emissions to help inform future policy decisions.

In addition, measurement of manifolded vents is analogous to EPA provisions for general stationary combustion sources that allow aggregate reporting of common flows – i.e., §98.36(c)(2) and (3) allow combustion sources to use aggregated volumes from common stacks and common fuel lines.

INGAA recommends that EPA add another paragraph (i.e., subsection) to §98.233 to indicate that direct, continuous measurement of vent lines, including manifolded lines, is an acceptable alternative to the source-specific procedures identified in §98.233.

Requirements for this alternative measurement approach should include the following:
•Owners and operators can elect to use continuous direct vent measurement as an alternative to other estimation methods defined in §98.233.
•Meters should be accurate to within 5%, as defined in Subpart A, §98.3(i).
•As with vent measurement under §98.233(p), the use of any acceptable measurement device should be allowed. For example, §98.233(p)(2)(ii) indicates, "Use a temporary meter such as, but not limited to, a vane anemometer or a permanent meter such as, but not limited to, an orifice meter…". [emphasis added] Any measurement device should be allowed that meets the accuracy criteria in Subpart A, §98.3(i).
• For manifolded vents that measure multiple sources, the company GHG Monitoring Plan would identify the sources emitting gas through the common vent and ensure that all applicable sources are addressed. The aggregated sources would also be identified in the annual report.
• To address aggressive schedule implementation, operators should be allowed to start continuous monitoring by October 1 of the first year – i.e., 3 months of data would be used to estimate annual emissions for the first reporting year.

INGAA recommends the following addition as §98.233(aa) to add this option to the Rule:

"(aa) Alternative Continuous Monitoring of Common Vent Lines. In lieu of the methods defined in §98.233, the owner or operator can elect to continuously monitor a vent line or lines that includes emissions from one or more sources identified in §98.232 for the industry segment, including common or manifolded vents lines that combine more than one source. The following requirements apply.
(i) The GHG Monitoring Plan and annual report shall identify the §98.232 sources addressed. The GHG Monitoring Plan shall describe the venting system, measurement basis, and data acquisition system.

(ii) The meter shall meet the requirements of §98.3(i).
(iii) Annual emissions shall be reported based on continuous monitoring throughout the year or upon facility startup with the exception of the initial reporting year, when continuous monitoring must be initiated no later than October 1 with annual emissions estimated based on three months of continuous monitoring data."

Response: EPA disagrees with the comment on compressor manifolded vent measurement. Please see response to comment EPA-HQ-OAR-2009-0923-1041-3. EPA has revised today's final rule to allow permanent meters on compressor vents, but not manifolded vents. Subpart A, and its instrument calibration procedures, applies to subpart W unless otherwise specified in subpart W. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section L. EPA has revised today's final rule Section 98.234(b) to clarify this.

Comment Number: EPA-HQ-OAR-2009-0923-0066-1
Organization: CMC Solutions and CMC Support
Commenter: Brian Swanson

Comment Excerpt Text:
Where continuous emission monitoring systems (CEMS) are required or may be required in the future we would offer that as an alternative predictive emission monitoring systems (PEMS) can be used as an alternative monitoring system. We are requesting that PEMS be written into the rule as an alternative wherever CEMS are required.

PEMS are a very cost effective and robust alternative to a CEMS and has proven itself in many 40 CFR Part 60 and 40 CFR Part 75 applications

Response: Subpart W does not require the use of CEMS, so this comment regarding PEMS does not apply.

Comment Number: EPA-HQ-OAR-2009-0923-0066-2
Organization: CMC Solutions and CMC Support
Commenter: Brian Swanson

Comment Excerpt Text:
PEMS as an Alternative to CEMS

U.S. regulations require continuous emissions monitoring systems (CEMS) and allow for the use of predictive approaches as an alternative providing the installed predictive emissions monitoring system (PEMS) meets rigorous performance specification criteria and the site performs ongoing quality assurance tasks such as periodic audits with portable analyzers and annual accuracy testing. PEMS have been used in the U.S. for gas turbine compliance monitoring under 40 CFR Part 60 for more than 20 years.

Prior to the promulgation of CEMS requirements in the U.S., process emissions were verified using simple parametric equations or manual stack test procedures (U.S. EPA Reference

Methods). Modern empirical PEMS have also evolved to meet the need for continuous monitoring of process emissions at the lowest possible cost. There are performance specification tests and periodic audits such as the annual relative accuracy test audit that are equivalent in cost as those required of compliance CEMS, however, PEMS can provide years of service with little or no ongoing operational or maintenance cost with a robust model developed and in place.

PEMS used for compliance are certified according to the rigorous standards specified using PS-16 (Part 60) or Subpart E (Part 75). These certifications require the PEMS to pass a relative accuracy test audit (RATA). In addition to these tests, SmartCEM™ provides additional quality assurance through EPA mandated performance tests. These include online input validation, drift analysis, input failure analysis, statistical analysis, model operating envelope analysis, and other automated procedures and tests as specified in 40 CFR Part 75, Subpart E and in 40 CFR Part 60, Appendix B, PS-16. The test results are used to evaluate a SmartCEM™ PEMS model prior to deployment and are presented to regulatory agents as part of the certification process. All performance tests are completed prior to RATA testing, such that the reference method RATA test witnessed by the regulatory agency is the final step in the procedure to achieve certification of a 40 CFR Part 60 compliance PEMS or for a 40 CFR Part 75 Subpart E application with the exception of the required report submittal and petition to U.S. EPA Administrator

Response: Please see response to comment EPA-HQ-OAR-2009-0923-0066-1.

Comment Number: EPA-HQ-OAR-2009-0923-1167-57
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Attachment C. Safety Issues Associated with GHG Reporting Rule Data Collection for Onshore Petroleum and Natural Gas Production

Test methods/procedures and job hazards assessments need to be completed to evaluate safe monitoring and measurement from Subpart W sources. EPA has not adequately contemplated the costs or time required to implement source measurements further discussed below. Noble requests that any source deemed unsafe to measure be placed on a list and accompanied with an explanation of the specific safety concerns. In the absence of measured data, Noble suggests using published emission factors or engineering estimates to be used in lieu of unsafe to monitor sources. Alternatively EPA should provide a method or procedure that allows the safe access and measurement of such sources.

Reciprocating Compressor Rod Packing Vents

Safety is a very significant issue when attempting to collect measurements from roofline vents at onshore natural gas processing facilities or gathering compressor stations. Safe access to and sample collection from leaking reciprocating compressor rod packing vents are mandatory. At these existing facilities, the majority of vents are routed outside the compressor building and elevated above the roof line to disperse potentially flammable gas vapor. In addition to gaining safe access to the elevated vent source, these vents are frequently manifolded with other vents or adjacent to blowdown vents that may automatically discharge to relieve pressure. Any measurement requirement that results in placing test personnel in a potentially dangerous environment is deemed unacceptable.

Resolution would likely require modifications to provide vent access from a safer location. However, line accessibility may not be readily available as the facilities were not constructed considering access. Engineering evaluations and analysis would be necessary to identify possible sample port locations. Due to the proposed schedule, this would put operators at risk of failing to comply with the annual survey requirement, or placing test personnel would be exposed to an immediate danger defying safety procedures. Therefore, additional time is required to implement the vent measurement program so that modifications can be made to accommodate measurement from a safer location than the vent exhaust from these elevated sources.

The majority of building roofline vents would be deemed inaccessible under conventional LDAR programs, as such components would be considered unsafe-to-monitor (UTM) or difficult-to monitor (DTM) in a typical LDAR program (i.e., components that cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface). In addition, a manlift is typically required to gain access over high pressure yard piping further complicating access and safety concerns for elevated vents. Under a typical LDAR program, monitoring can be deferred due to unsafe or difficult-to-monitor components. In response, the facility must maintain documentation that explains the conditions under which the components become safe to monitor or no longer difficult to monitor. For vent lines at most gathering compressor stations, typical conditions under which these vents would be “safe” would preclude normal engine operations or pressurized scenarios where the potential for a vented release is possible.

Leak detection and repair (LDAR) programs are required as part of 40 Code of Federal Regulations (CFR) Part 60 (NSPS), 40 CFR 61 (NESHAP), 40 CFR 63 (MACT), and 40 CFR 264 (Hazardous Waste Handling). LDAR requirements provide allowances for identification and explanation for any equipment that is:

- unsafe to monitor (UTM) – Exposing test personnel to an immediate danger as a consequence of monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, high pressure piping, proximity to heated, sharp, or rotating equipment, or would risk damage to equipment.

- difficult to monitor (DTM) – obstructed access (e.g. insulated), elevated access > 2 meters required, limited access to component

- inaccessible - Obstructed by equipment, piping, or insulation that prevents access to the connector by a monitor probe; Buried or confined space entry prohibits access to measurements.

DTM and UTM provisions for accommodating safety related concerns or measurement or monitoring access need be considered and allowances for estimating these sources provided.

Pressurized Vessel Liquid Sample Collection

Care must be taken to safely obtain liquid samples from pressurized vessels. These pressure vessels have a wide range of operating temperatures and pressures. When mishandled, samples taken from high-pressure systems can cause serious injury, or even death. Even a small pinhole in a high-pressure line can cause serious injury. Whenever a sample is drawn, every precaution necessary must be taken to ensure the safety not only of the sample collector, but also of those working around the system. As with all high-pressure sampling systems, appropriate safety precautions must be followed. Sampling procedures and taps must be properly sighted and installed to reduce safety concerns. The cost and burden for safely accessing these samples has not been considered or addressed.

Other Related Safety Concerns

Safety training for fall protection and hydrogen sulfide (H2S) or respirator certification will be required for most test personnel to allow safe measurement from vents and component population counts. Unlike the downstream sector, field natural gas may contain higher levels of hydrogen sulfide (highly toxic and flammable gas) and higher quantities of nitrogen or carbon dioxide (potential asphyxiants). Potential exposure to these high concentrations of these compounds requires training, safety awareness, proper certifications, and field/facility overviews prior to conducting any measurement activities. In addition, hot work permits are required for any equipment or instrument that is not intrinsically safe. This permit adds to the cost and implementation burdens and has not been considered by EPA in the cost analysis.

Response: EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11. For certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1074-12
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
75 FR 18621: 1. Direct Measurement

Comment: WBIH strongly requests EPA to consider flexibility with monitoring and measurement methods of vents to ensure the safety of personnel conducting these tasks.

WBIH's number one priority is the safety of our employees and contractors providing service at our facilities. This proposed rule requires very prescriptive requirements for monitoring and measurement of components requiring access to vents located outside, in high locations, both on tanks and building roofs. Each WBIH comment has been developed with safety at the forefront of the process

Response: EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.

Comment Number: EPA-HQ-OAR-2009-0923-1026-14
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
Safety Concerns

The proposed rule does not allow exemption's [*sic*] for difficult or unsafe to monitor components. Under the previously proposed Subpart W "component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded." EPA had acknowledged that some of the components included in the inventory would be located at areas that are either unsafe to access or located such that gaining accessibility would require additional and costly measures such as cranes or lifts. The unsafe difficult to monitor provisions should be incorporated into the currently proposed Subpart W to ensure the safety of personnel and limit the undue burden of reporting

Response: EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.

Comment Number: EPA-HQ-OAR-2009-0923-1024-1
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
EPA should not require reporting from individual components that cannot be monitored without placing employees' safety at risk, or that are physically inaccessible.

Response: EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.

Comment Number: EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
Direct measurement is not appropriate for any sources.

GPA feels that direct measurement is not appropriate for any sources for the purposes of GHG emission inventories, consistent with other emission inventory practices. Although EPA has reduced direct measurement requirements in the current proposal for Subpart W, EPA continues to employ methods that ignore longstanding and accepted international protocols for emission inventory calculations. The API Compendium in particular has been accepted as an international standard for estimating GHG emissions across the oil and gas industry. For example, Australia NGERS, EU-ETS, and Alberta emission inventories are all based on the API Compendium. EPA is assuming that a significant increase in overall accuracy will result by requiring more complex and costly estimation of GHG emissions from even the smallest sources within the natural gas gathering and processing industry. This assumption is made while overlooking the EPA's own data that indicates the natural gas gathering and processing industry emits only a very small fraction of the total US GHG emissions annually. In addition, the currently proposed Subpart W ignores the standards of statistical averaging.

While GPA supports the full use of the API Compendium to calculate GHG emissions for all sources covered by the proposed Subpart W, at a minimum we suggest the application of the API Compendium in place of any direct measurement methods. For the gas gathering and processing sector, direct measurement is generally proposed to be limited to compressor wet seal vents and rod packing venting. The current proposal potentially requires direct measurement of compressor rod packing vents from every cylinder of a compressor in cases where the vent lines are not tied to a common line, which is a common practice in gathering compression facilities and production facilities. The prescribed methods for these sources is flawed by assuming a snapshot measurement applied across an entire year is more accurate than an emission factor based on well documented and controlled studies.

Response: EPA disagrees with the comment that direct measurement is not appropriate for any source. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) Section II.L, and the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees that the API Compendium is suitable for all sources covered by subpart W. Please see response to comment EPA-HQ-OAR-2009-0923-1206-47.

Comment Number: EPA-HQ-OAR-2009-0923-1061-9
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
Direct measurement requirements should be eliminated from the rule. TPA objects to any requirement for direct measurement of emissions from equipment covered by Subpart W. Direct measurement of fugitives is the most cost-intensive component of the proposed rules. In addition, EPA should consider the fact that there would be significant greenhouse gas emissions associated with the burdensome efforts required to implement and perform direct measurement protocols, e.g. emissions caused by sending crews all across the State of Texas to perform the direct measurement required by the rule. Further, direct measurement of emissions only shows the emissions levels that exist at a single point in time, meaning that data collected by direct measurement methods is not representative of ongoing annual emission from the sources at issue.

Simpler and much more efficient data collection may be obtained through the use of methodologies such as those presented in the Compendium of Greenhouse Gas emissions Estimation Methodologies for the Oil and Gas Industry, developed by the American Petroleum Institute, dated 2004, or as subsequently revised ("API Compendium"). TPA strongly urges EPA to revise Subpart W to allow for the estimation and calculation of fugitive emissions through the use of approved factors in place of the onerous detection and measurement provisions that are being proposed. Methodologies such as are provided in the API Compendium are used in connection with permits and emissions inventories, and as such they should be sufficient for use in connection with a reporting rule such as Subpart W.

Response: Please see response to comment EMAIL-0002-9 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1018-5
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
Pre-amble, page 21, "In this supplemental proposal, EPA is requiring the use of direct measurement of emissions for only the most significant emissions sources where other options are not available, and proposing the use of engineering estimates, emissions modeling software, and leak detection and publicly available emission factors for most other vented and fugitive sources."

- Given the sheer number of sources for which emission estimates are required, CAPP supports the use of engineering estimates, emission modeling software and publicly available emission factors as an alternative to direct emission measurement. Direct measurement of GHG emissions is technically challenging and impractical for the scale of reporting that is envisioned due to the basin level reporting approach. In addition, the direct measurement of some emission sources results in safety issues. While the proposed emission estimation methods represent a much more feasible approach, the required volume of data gathering, sampling and analysis is still daunting.

Response: EPA disagrees with the comment that direct measurement is not appropriate. Please see The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98); preamble Section II.L, and the Technical Support Document (TSD) for today’s final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees with the comment regarding onshore production cost. Please see response to comment EPA-HQ-OAR-2009-0923-1011-29 and the preamble Section III.B. EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.

Comment Number: EPA-HQ-OAR-2009-0923-1029-5
Organization: Western Business Roundtable
Commenter: Holly Propst

Comment Excerpt Text:
There Are Other Means to Get Meaningful Data

We agree with the suggestion posed by oil and gas sector organizations: there are other emissions estimating tools available to assist EPA in gauging the impact of oil and gas-related emissions. EPA's own Natural Gas Star program is one such tool. Industry is also developing methodologies and tools to calculate GHG emissions for the sector.[148] These approaches seem a better path to pursue than expansive regulatory requirements that will fall disproportionately on small businesses.

Response: EPA disagrees that the API Compendium is appropriate for all sources; please see the response to comment EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923). EPA's Natural Gas STAR Program, while valuable, is a voluntary tool and would not provide the comprehensive data across industry segments and encompassing emissions sources as would be received through the GHG reporting program. Also, Gas STAR data is not based on set data collection and measurement methodologies and the data reported by partners are emissions reduced, not total emissions as will be collected under the MRR. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section I.D.

Comment Number: EPA-HQ-OAR-2009-0923-1039-35
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
The Rule Should Include Alternative Tools for Vent Measurement and Vent Emissions Detection

To provide flexibility, the Final Rule should allow all reasonable technologies and methods for measuring leaks from reciprocating compressor rod-packing vent using a suite of technologies and methods to provide flexibility. Alternative tools (e.g., high volume sampler) for vent measurement should also be included provided that the vent rate is within the acceptable range of the instrument. Thus, §98.233(p)(2) should reference §98.234(c) to allow use of calibrated bags and §98.234(d) to allow use of a high volume sampler. The Proposed Rule should also reference §98.234(a)(1) within §98.233(p)(2)(i) to allow optical camera screening of elevated vents prior to measurement.

INGAA requests that EPA broaden the list of allowed detection and measurement tools to include all demonstrated technologies and alternatives that are used in practice. EPA studies have employed all of the recommended measurement and leak detection technologies discussed below in previous field studies. These "tools" provide the necessary flexibility to screen leaking components via alternative techniques that may be more suitable to ambient conditions, available equipment, or survey team experience level.

[148] See, for example, the American Petroleum Institute's Gas Emissions Estimation Methodologies for the Oil and Gas Industry.

Since EPA proposes to require optical gas imaging for fugitive component screening and natural gas transmission condensate tank vent monitoring, INGAA is curious why EPA elected to exclude this technology for detecting leaks from elevated vent sources. Screening the compressor rod-packing vent using an optical gas imaging instrument would provide a safer method for detecting leakage through roofline vents and eliminate the need to measure non-leaking, difficult-to-access vents. Unsafe or difficult-to-monitor compressor rod-packing vents with visible leaks could be measured using conventional sampling or metering – if the vent can be accessed at an alternative location in the line.

Safe access to measure roofline vent lines and condensate tank vents, or alternative sampling locations, will need to be integrated into existing facilities. Thus, during the initial year, INGAA recommends phasing in these measurements (see Comment XII). INGAA recommends reporting combustion and some vented emissions starting in year one and phasing in measurement and monitoring over three years. Other phase-in options include precluding inaccessible vents from reporting during initial years, or allowing vent screening using optical imaging. In the latter case, if the camera detects vented emissions, a measurement would be completed if the vent is safely accessible. If not accessible, vent status would be noted in the report and measurement would be initiated in the second or third year after safe access has been established.

EPA should be familiar with these alternative "tools" and methods as all been have been used to identify, quantify, and/or report venting losses under other EPA programs including Natural Gas STAR.

Response: EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA agrees that the reciprocating compressor rod packing monitoring method Section 98.233(p)(2)(i) should include references to Section 98.234 for both calibrating bagging and high volume sampler methodologies, and today's final rule has been revised. However, EPA disagrees that it should require optical gas imaging leak detection in Section 98.233(p), as all vents must be measured. EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11. EPA disagrees with the comment regarding a phased-in approach. However, EPA has determined that for specified emissions sources for certain industry segments, some reporters may need more time to comply with the monitoring and QA/QC requirements of Subpart W by January 1, 2011. For certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1040-2
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

<u>Comment Excerpt Text:</u>
The reporting burden can be significantly reduced without compromising data quality by: (1) establishing de minimis cutoffs for certain operations; (2) allowing emissions estimates based on the API Compendium for upstream production sites with emissions of less than 3,000 metric tons

per year ("tpy") CO_2e; (3) providing more flexibility in determining emissions for upstream production sites with emissions of more than 3,000 tpy CO_2e; (4) eliminating reporting of emissions from portable non-self-propelled equipment because EPA can develop a reasonable estimate based simply on the number and type of wells completed; and (5) eliminating direct measurements, which would be inordinately costly and would not provide better data quality than existing, widely accepted estimating techniques.

Response: Regarding the comments on de minimis and revised methodologies in today's final rule, please see response to comment EPA-HQ-OAR-2009-0923-1018-2. EPA disagrees with the comment on a threshold for onshore production sites. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees with the comment that direct measurement is not appropriate. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.L, and the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees with the comment regarding onshore production cost. Please see response to comment EPA-HQ-OAR-2009-0923-1011-29 and the preamble Section III.B. EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11. EPA disagrees with the comment on combustion emissions from portable equipment. Please see the Technical Support Document EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-1206-24
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Additionally, the API Compendium in particular has been accepted as an international standard for estimating GHG emissions across the oil and gas industry. For example, Australia NGERS, EU-ETS, and Alberta emission inventories are all based on the API Compendium. EPA is assuming that a significant increase in overall accuracy will result by requiring more complex and costly estimation of GHG emissions from even the smallest sources within the natural gas gathering and processing industry. This assumption is made while overlooking the EPA's own data that indicates the natural gas gathering and processing industry emits only a very small fraction of the total US GHG emissions annually. In addition, the currently proposed Subpart W ignores the standards of statistical averaging.

While GPA supports the full use of the API Compendium to calculate GHG emissions for all sources covered by the proposed Subpart W, at a minimum we suggest the application of the API Compendium in place of any direct measurement methods. For the gas gathering and processing sector, direct measurement is generally proposed to be limited to compressor wet seal vents and rod packing venting. The current proposal potentially requires direct measurement of compressor rod packing vents from every cylinder of a compressor in cases where the vent lines are not tied to a common line, which is a common practice in gathering compression facilities and production facilities. The prescribed methods for these sources is flawed by assuming a snapshot measurement applied across an entire year is more accurate than an emission factor based on well documented and controlled studies.

Response: EPA disagrees with the comment that direct measurement is not appropriate. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.L, and the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees that the API Compendium is suitable for all sources covered by subpart W. Please see response to comment EPA-HQ-OAR-2009-0923-1206-47. As explained in Section II.E of the preamble, EPA has decided not to include monitoring and reporting requirements for gathering lines and boosting stations at this time.

Comment Number: EPA-HQ-OAR-2009-0923-1155-10
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Direct Measurement
We support the use of direct measurement for all source categories as our preferred measurement and reporting method, because it is the most accurate method. The petroleum and natural gas industry has some of the most economically attractive alternatives to control emissions at a significant profit, and is a source category where emissions are, by EPA's own admissions, dramatically underestimated. For this reason, we believe that more accurate emission measurement should be required. Requiring more accurate measurement will provide further economic incentive for Operators to install profitable emission control.

EPA has modified the Subpart W rule from its original proposal 35 to rely much less on direct measurement and more on engineering estimates developed by computer models, emission factors and engineering calculations.[149]

For all of the same reasons identified in our comments on EPA's original MRR proposal,[150] we strongly support the use of direct measurement wherever possible, with a high priority on its use for complex systems and those with a high potential for fugitive emissions, such as are found in the oil and gas sector. EPA must, as previously stated in our comments on the original rule, develop mechanisms to move the reporting system steadily towards the most accurate and precise reporting methods possible which will mean moving towards the use of more direct measurement methods and will also mean systematically and periodically auditing and reviewing the proposed reporting requirements to ensure continuous improvement in the reported data.

The difference between emissions measured directly and those that are estimated through engineering methods can be significant. Unless direct measurement techniques are employed, unintended emissions will go undetected and the emissions estimates, in general, cannot be as

[149] See 75 Fed. Reg. 18625, April 12, 2010.

[150] EPA-HQ-OAR-2008-0508-0635.

accurate and precise as those obtained through actual measurements. In fact, this sector, in particular, has seen, and EPA has documented in its Technical Support Document (TSD) for this proposed rule, an enormous uncertainty in emissions estimates over the years. The degree to which we've seen emissions estimates grow suggests there is a clear need to continually monitor the quality of the data being reported. This need comes from the high level of uncertainty in emissions characterization for this particular source sector. In the absence of requirements for direct measurement, EPA should take every possible action to ensure that emissions factors and estimates used are as accurate as possible by developing a sampling and audit program, as discussed at #10 below.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1155-12. EPA disagrees with the comments on auditing, please see EPA's response on verification in The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.N.

Comment Number: EPA-HQ-OAR-2009-0923-1155-4
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Emissions Are Seriously Under Estimated for this Source Category
A primary concern for the petroleum and natural gas systems is that EPA and other scientists have documented a serious trend of emissions under-reporting for this source category. Emissions underreporting is well documented in EPA's own Technical Support Document (TSD) for the proposed MRR, where EPA concludes that several emissions sources are "significantly underestimated" in the 1996 U.S. GHG Inventory.[151] More specifically, EPA identified concerns with emission accuracy for the following sources: (1) well venting for liquids unloading; (2) gas well venting during well completions; (3) gas well venting during well workovers; (4) crude oil and condensate storage tanks; (5) centrifugal compressor wet seal degassing venting; and (6) flaring. According to EPA, the emissions estimates for these sources "do not correctly reflect the operational practices of today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory".[152]

In the TSD, EPA includes revised emission factors for four of these underestimated sources leading to revised emissions estimates ranging from ten times higher (for well venting from liquids unloading) to 35 times higher (from gas well venting from conventional well completions) to as much as 3,500 and 8,800 times higher (for gas well venting from completions and well workovers of unconventional wells, respectively).[153] Overall, the revisions to just these three sources and compressor wet seals would result in a more than 100% increase in estimated

[151] These errors owe to errors in the underlying source data which in turn comes from the 1996 EPA/GRI/Radian Greenhouse Gas Emission Inventory. See EPA Technical Support Document at p.7.

[152] See EPA Technical Support Document at p.23.

[153] See EPA Technical Support Document, Table 1, at p.8 and Appendix B.

emissions from the oil and gas production sector and a 67% increase in estimated emissions from the transmission and storage sector.[154]

These enormous underestimates are, alone, reason enough to insist on more reliance on direct measurement of emissions from these sources and systematic auditing of reporting methods. However, there is even more evidence that the emissions estimates for these and other sources remain uncertain and continue to be greatly underestimated.

An area of particular uncertainty is gas well completions and well workovers. As EPA notes in the preamble to the proposed reporting rule:

"[N]o body of data has been identified that can be summarized into generally applicable emissions factors to characterize emissions from these sources [(i.e., from well completion venting and well workover venting)] in each unique field. In fact, the emissions factor being used in the 2008 U.S. GHG Inventory is believed to significantly underestimate emissions based on industry experience as included in the EPA Natural Gas STAR Program publicly available information (http://www.epa.gov/gasstar/). In addition, the 2008 U.S. GHG Inventory emissions factor was developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country."[155]

The 2008 U.S. GHG Inventory emphatically states that "[n]atural gas well venting due to unconventional well completions and workovers, as well as conventional gas well blowdowns to unload liquids have already been identified as sources for which Natural Gas STAR reported reductions are significantly larger than the estimated inventory emissions."[156] And, in response to questions from Environmental Defense Fund, EPA responded that: "presently, [reduced emission completions (REC)] reductions reported in the Natural Gas STAR body of work is larger than well completion venting in the inventory on an annual basis."[157] Specifically, the U.S. GHG Inventory is based on an emission factor of a little over three thousand standard cubic feet (3 Mcf) per gas well drilled and completed.[158] Yet, Natural Gas STAR program partner experience shows several cases where emission factors were thousands of times higher than that shown in the 2008 inventory. Examples include: (1) a BP project employing green completions

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[154] See EPA Technical Support Document, Table 2, at p.9.

[155] 75 FR 18621

[156] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, p. 3-47.

[157] See "Environmental Defense Fund (EDF) Questions & USEPA Answers – June 1, 2010" posted to the Docket for this action on June 2, 1010, Docket ID EPA-HQ-OAR-2009-0923-0070.

[158] Table A- 118: 2008 Data and CH4 Emissions (Mg) for the Natural Gas Production Stage, p. A-144, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. 11 See Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/green_c.pdf, slide.

at 106 wells and reporting 3,300 Mcf of gas recovered per well;[159] All of these examples include gas recovery estimates more than 1,000 times higher than the 3 Mcf of gas per well estimated in the U.S. GHG Inventory for 2008. These data are consistent with the unconventional gas well completion and workover data presented in EPA's TSD for the MRR. Specifically, Appendix B on pp. 79-82 includes four examples from the Natural Gas STAR program with gas completion rates of 6,000 Mcf, 10,000 Mcf, 700 Mcf and 20,000 Mcf per completion. EPA used an average of these four data points for its emission factor for this source (i.e., 9,175 Mcf/completion). Using this factor resulted in estimated emissions from completions of conventional and unconventional wells of 86 billion standard cubic feet (Bcf). In comparison, the U.S. GHG Inventory reports emissions of just 0.1 Bcf of gas from drilling and well completions.[160]

More generally, Natural Gas STAR partners reported recovering between 7 and 12,500 Mcf (average of 3,000 Mcf) of natural gas from each cleanup with the potential for an estimated 25 Bcf of natural gas recovery from green completions annually in 2005 compared with the annual U.S. GHG Inventory total for "Drilling and Well Completion" of just 0.1 Bcf in 2008.[161,162] And more recently, EPA's Natural Gas STAR program attributed 45 Bcf of gas to Reduced Emissions Completions (RECs) in 2008 (representing 50 percent of EPA's Natural Gas STAR program's annual total reductions).[163] If, in fact, the emission factor for well completions were at least 1,000 times higher than what is reported in the U.S. GHG Inventory (e.g., if it were at least 3,000 Mcf instead of 3 Mcf) this would add 100 Bcf to the total estimated emissions from natural gas systems, raising the total from 240 Bcf to 340 Bcf in 2008 (a 40% increase).[164]

A New York Times article published on October 15, 2009, reports that EPA is currently

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[159] See attached 2009 workshop presentation by Devon, slides 3 and 13. 6,300 Mcf = 11.4 Bcf / 1,798 wells.] (2) a Devon Barnett Shale project employing green completions at 1,798 wells between 2005 and 2008 and reporting 6,300 Mcf of gas recovery per well;12 and (3) a Williams project employing green completions at 1,064 wells in the Piceance Basin reporting 23,000 Mcf of gas recovered per well.[Footnote 13: See Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/workshops/pennstate2009/robinson1.pdf, slide 16. We note that the reported Williams reductions appear to assume an average of 32 days of uncontrolled venting during flowback, which seems like an unreasonably long length of time.

[160] See Table A-125: CH4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg. (2.05 Gg * 0.052 ft3/g = 0.1 Bcf).

[161] See http://www.epa.gov/gasstar/documents/green_c.pdf, slides 9 and 5.

[162] See Table A-125: CH4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg.

[163] See 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50% are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[164] See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-38 CH4 Emissions from Natural Gas Systems (Gg), p. 3-45. Total emissions in Bcf: 4,591 Gg * 0.052 ft3/g = 240 Bcf.

reviewing and revising its estimate of methane emissions from U.S. gas wells.[165] According to the article:

"An E.P.A. review of methane emissions from gas wells in the United States strongly implies that all of these figures may be too low. In its analysis, the E.P.A. concluded that the amount emitted by routine operations at gas wells — not including leaks like those seen near Franklin — is 12 times the agency's longtime estimate of nine billion cubic feet. In heat-trapping potential, that new estimate equals the carbon dioxide emitted annually by eight million cars."[166] In fact, the TSD for the MRR includes an estimate of 120 Bcf for U.S. completion and workover venting (2007). As previously discussed, this estimate is based on an emission factor of 9,175 Mcf per completion or workover. Given the sparse data (4 data points) and the enormously wide range of potential emission factor values from this source (ranging from 700 to 20,000 Mcf) even the recently revised estimates may very well continue to underestimate emissions from this source. While it is clear that EPA acknowledges the lack of accurate emissions factors for well completions, the enormous variation – more than three orders of magnitude - between different work sites and between work sites and EPA's suggested emissions factors demonstrates that need for at least some direct measurement and study sufficient to develop more reliable emissions factors.

The statistical representation of the U.S. GHG Inventory data includes a 95 percent certainty range within which emissions from this source category are likely to fall for the year 2008. This range, for Natural Gas Systems, includes a lower bound of -24% and an upper bound of +43%.[167] As noted in the uncertainty analysis, "[t]he heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry."[168] And as a result, basing an emission factor on only a few "representative" sources when considering the highly variable rates measured among these sources, results in a potentially high degree of uncertainty as reflected in the reported uncertainty range.

Clearly, the EPA-acknowledged discrepancies between the inventory emissions reported to-date and the Natural Gas STAR reported reductions and the high degree of uncertainty in both of these data sources must be reconciled with rigorous reporting rule requirements for the oil and gas sector and, in particular, for vented emissions from wells. And in order to place more certainty on the numbers being reported EPA will need to employ a rigorous sampling and auditing program to verify reported emissions. This particular source category demonstrates the desperate need for more reliability in emissions reporting from the oil and gas sector.

Onshore production and processing storage tanks are an additional source with a potential for high uncertainty in estimated emissions. A study prepared for the Texas Environmental Research

[165] See www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html#.

[166] See www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html#.

[167] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-41, p. 3-46.

[168] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3- 46.

Consortium measured emissions rates from several oil and condensate tanks in Texas and developed average emission factors based on direct measurement of vent gas flow rates.[169] The study determined "the direct measurement approach to be the most accurate for estimating oil and condensate storage tank emissions at wellhead and gathering sites; however, other, less accurate, approaches appear to be much more commonly used." EPA proposes the use of modeling (E&P Tank) to calculate emissions from storage tanks in the MRR. Yet, the TSD acknowledges significant weaknesses with this approach.[170] Again, only a move towards more direct measurement (e.g., direct measurement of gas oil ratios, vent gas and flow rates) will reduce these uncertainties in the reported data. Finally, as previously mentioned in our comments on the original reporting rule proposal, Canadian natural gas processing plants discovered methane emissions roughly an order of magnitude higher than estimated demonstrating the critical need for comprehensive direct measurement of emissions from this significant sector of GHG emissions.[171]

Certain oil and gas sources are of particular importance due to the magnitude of their emissions. These sources will require the best possible reporting requirements if the data gathered are to be representative and of further use. In particular, uncertainties in data reported across a large population of sources (e.g., the hundreds of thousands of pneumatic devices used throughout the oil and gas sector) have the potential to greatly reduce the value of the dataset. Pneumatic devices are a prime example of a source that is particularly important in terms of magnitude and is also important due to the sheer number of sources and the associated compounding effects of the uncertainty associated with each individual source. The magnitude and importance of this emissions source support a greater emphasis on direct measurement (e.g., metering) and on rigorous verification and audit for any reporting that will be based on engineering estimates (e.g., OEM emission factors).

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1155-12. In addition, EPA disagrees with the comment on verification. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.N.

Comment Number: EPA-HQ-OAR-2009-0923-1201-11
Organization: North Slope Burough
Commenter: Edward S. Itta

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[169] Hendler A., Nunn J., Lundeen J., McKaskle R., "VOC Emissions from Oil and Condensate Storage Tanks Final Report", April 2, 2009, available online at http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf] The U.S. GHG Inventory mentions this study but indicates that "[b]ecause of the limited dataset and unexpected jumps in data points which can be attributed to non-flashing emission affects, the United States decided that further investigation would be necessary before updating the inventory emission factor."[Footnote 24: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3- 47.

[170] See EPA Technical Support Document, at p.134.

[171] See Allan K. Chambers et al., DIAL Measurements of Fugitive Emissions from Natural Gas Plants and the Comparison with Emission Factor Estimates (also processing plants to be roughly an order of magnitude higher than estimated emissions of volatile organic compounds and benzene).

Comment Excerpt Text:

Natural gas processing plants Comments on the original reporting rule identified Canadian natural gas processing plants that have discovered methane emissions roughly an order of magnitude higher than estimated, demonstrating the critical need for comprehensive direct measurement of emissions from this significant sector of GHG emissions[172]

Response: EPA considered the monitoring method for each source and in several cases in onshore natural gas processing it determined that direct measurement was not necessary. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1201-6
Organization: North Slope Burough
Commenter: Edward S. Itta

Comment Excerpt Text:

EPA Should Place a High Priority on the Use of Direct Measurement and Should Implement a Sampling and Audit Program to Provide for Periodic Improvements to the Proposed Data Collection Program.

Under EPA's proposed reporting rule for the oil and gas sector, facilities would be required to quantify greenhouse gas emissions according to a range of methods. Methods include the direct measurement of emissions, engineering estimation methods (e.g., simulation models, engineering calculations, original equipment manufacturer emission factors, and default emission factors), leak detection and leaker emission factors as well as equipment count and population emission factors.

In its supplemental reporting rule for the oil and gas sector, EPA has significantly modified its original proposal.[173] We strongly support the use of direct measurement wherever possible, especially for complex systems and those with a high potential for fugitive emissions (such as are found in the oil and gas sector). EPA should develop mechanisms to move the reporting system steadily towards the most accurate and precise reporting methods possible. This will require moving towards the use of more direct measurement methods and systematically reviewing the proposed reporting requirements to ensure continuous improvement in the reported data.

The difference between emissions measured directly and those that are estimated through engineering methods can be significant. Emissions estimates generally cannot be as accurate and

[172] See Allan K. Chambers et al., DIAL Measurements of Fugitive Emissions from Natural Gas Plants and the Comparison with Emission Factor Estimates (also finding fenceline measurements of Canadian natural gas processing plants to be roughly an order of magnitude higher than estimated emissions of volatile organic compounds and benzene), referenced in Comments EPA-HQ-OAR-2008-0508-0635.

[173] See 74 FR 16448, April 10, 2009.] to rely much less on direct measurement and more on engineering estimates, leaker factors and emissions factors [Footnote 18: See 75 FR 18625.

precise as those obtained through actual measurements, and they allow for unintended emissions to go undetected. The oil and gas sector has seen (and EPA has documented in its Technical Support Document (TSD) for this proposed rule) an enormous uncertainty in emissions estimates over the years. The degree to which emissions estimates have grow suggests there is a clear need to continually monitor the quality of the data being reported.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1155-12. In addition, EPA disagrees with the comment on verification. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.N.

Comment Number: EPA-HQ-OAR-2009-0923-1201-7
Organization: North Slope Burough
Commenter: Edward S. Itta

Comment Excerpt Text:
The Number of Source Categories with Significantly Underestimated Emissions is Considerable.

The TSD for the proposed reporting rule includes a discussion of several emissions sources believed to be "significantly underestimated" in the U.S. GHG Inventory.[174] Specifically, EPA identifies the following sources: (1) well venting for liquids unloading; (2) gas well venting during well completions; (3) gas well venting during well workovers; (4) crude oil and condensate storage tanks; (5) centrifugal compressor wet seal degassing venting; and (6) flaring. EPA states that the emissions estimates for these sources "do not correctly reflect the operational practices of today" and "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[175]

In the TSD, EPA includes revised emission factors for four of these underestimated sources leading to revised emissions estimates ranging from ten times higher (for well venting from liquids unloading) to 35 times higher (from gas well venting from conventional well completions) to as much as 3,500 and 8,800 times higher (for gas well venting from completions and well workovers of unconventional wells, respectively)[176],[177] Overall, the revisions to just these three sources and compressor wet seals would result in a more than 100 percent increase in estimated emissions from the oil and gas production sector and a 67 percent increase in estimated emissions from the transmission and storage sector[178].
These enormous underestimates are, alone, reason enough to require greater reliance on direct measurement of emissions from these sources and systematic auditing of reporting methods. But there is even more evidence that the emissions estimates for these and other sources remain uncertain and continue to be greatly underestimated.

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[174] See Technical Support Document (TSD) at 7, citing EPA/GRI/Radian, 1996.

[175] Id. at 23.

[176] Id. at 23.

[177] See Table 1 of TSD at 8 and Appendix B.

[178] See Table 2 of TSD at 9.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1155-4.

Comment Number: EPA-HQ-OAR-2009-0923-1037-2
Organization: ENVIROTECH ENGINEERING
Commenter: Terence Trefiak

Comment Excerpt Text:
Direct Leak Measurement

It is our understanding that the revised proposed EPA rule has excluded the requirement to quantify leak rates and instead have recommended using published emission factors base on component type. We understand that this was done to try and reduce the perceived burden/cost of completing a fugitive emission assessment. Based on our experience, we believe that direct measurement of leaks is a crucial component to a successful fugitive emission managements program and the costs of direct measurement are usually a small portion of the total cost of a fugitive emission assessment.

Firstly, by measuring a leak we provide our clients with the economic information needed to make appropriate decisions on repair activities. You can have two of the exact same components, one leaking at high rate (5 cfm) and one leaking at a low rate (0.05 cfm). The priority and urgency of repair will vary depending on the leak rate.

Response: EPA disagrees that direct measurement is applicable for all equipment leaks. Please see the response to comment EPA-HQ-OAR-2009-0923-1155-12.

Comment Number: EPA-HQ-OAR-2009-0923-1007-2
Organization:
Commenter: Anonymous

Comment Excerpt Text:
EPA should also require direct measurement of emissions. Using equations to estimate emissions is inaccurate.

Response: EPA disagrees that direct measurement is appropriate for all emissions sources. Please see the response to comment EPA-HQ-OAR-2009-0923-1155-12.

Comment Number: EPA-HQ-OAR-2009-0923-1083-2
Organization:
Commenter: A. Bhaskar

Comment Excerpt Text:
EPA should require direct measurement of emissions. Using equations to estimate emissions is inaccurate. We need direct measurements to ensure the data is accurate to develop the best policy.

Response: EPA disagrees that direct measurement is appropriate for all emissions sources. Please see the response to comment EPA-HQ-OAR-2009-0923-1155-12.

Comment Number: EMAIL-0008-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Emerson Process
Commenter: Patrick Truesdale

Comment Excerpt Text:
Can coriolis meters which are installed/calibrated/maintained according to consensus industry standards (API/AGA) be used to measure Natural gas and still gas flow for both Subpart C and Subpart W facilities?

Response: This response to comment is only in regard to subpart W sources. Questions regarding subpart C must be directed to EPA directly as that subpart is final. Under the proposed subpart W, facilities would be able to use coriolis meters where such meter types are allowed under subpart W, provided they meet the calibration and accuracy requirements in 40 CFR 98.3(i) and those set forth in subpart W Monitoring and QA/QC Requirements.

Comment Number: EPA-HQ-OAR-2009-0923-0133-1
Organization: Leak Surveys Inc.
Commenter: David Furry, President and Owner

Comment Excerpt Text:
First, we strongly urge the agency to include some requirements for training and on-going experience into the Subpart W reporting rule. Part 98.234(a)(1) stipulates "Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, SECTION 60.18 (i)(1) and (2) Alternative work practice for monitoring equipment leaks." Along with many in the industry, we thought that the lack of specific training and on-going operation was an inherent problem potentially leading to unqualified technicians performing surveys and, consequently, missing leaks. Our experience with our own training program has shown that, until a technician has at least 250 "eye" hours behind the camera, the potential to overlook leaks is relatively high.

In addition, the Texas Commission on Environmental Quality (TCEQ) also noted this deficiency and has added a training provision to the Texas version of the AWP. Under the TCEQ AWP proposed methodology[179], it is recommended that:

(A) The operator of the optical gas imaging instrument must receive a minimum of 24 hours of initial training on the specific make and model of the optical gas imaging instrument before using the instrument for the purposes of this supplemental leak detection.

[179] Section SECTION 101.153, Voluntary Supplemental Leak Detection Program in subsection 101.153(b)(4),

(B) Operators using optical gas imaging instruments for this supplemental leak detection shall comply with one of the following requirements for on-going training purposes:

(i) Operators shall attend an annual eight-hour refresher training class on the optical gas imaging instrument used for this supplemental leak detection; or

(ii) Operators shall maintain a minimum of 100 hours per calendar year of hands-on operational experience with the model of optical gas imaging instrument used for the supplemental leak detection. Operators electing this option shall maintain a written log of the operator's operational experience with the optical gas imaging instrument.

We would recommend that similar language be added to the EPA reporting rule, and we strongly recommend that 40 hours of training in general optical imaging technology be stipulated instead of 24 hours. However, we don’t believe (as stipulated in the TCEQ proposed rule) that the training be specific to the make and model of camera, but rather needs to be specific to basic camera and leak technology. Additionally, we believe it is vital in obtaining quality surveys, that any technician performing services under this rule must maintain at least 100 hours per year of documented camera usage to maintain skills.

Response: EPA disagrees with adding mandatory training to the Alternative Work Practice for 40 CFR part 60, subpart A, Section 60.18. Today’s final rule stipulates that reporters must operate the optical gas imaging instrument in accordance with the instrument manufacturer’s operating parameters and therefore EPA does not deem mandatory training necessary. Training is not specified in subpart W. Subpart W does not supersede existing regulations and requirements regarding training.

Comment Number: EPA-HQ-OAR-2009-0923-0133-5
Organization: Leak Surveys Inc.
Commenter: David Furry, President and Owner

Comment Excerpt Text:
Section 98.233 (p) Reciprocating compressors rod packing, subsection (2) (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing unit isolation valves and blowdown valves using bagging according to methods set forth in 98.234 (c). From our experience, the blow down vents seldom leak and we suggest that the optical imaging camera be used from the ground to first determine which, if any of the vents need to be measured. We also seek clarification on whether to use emission factors or direct measurement on leaks found on a reciprocating compressor valves or gas found to be leaking around the packing itself (vented to the atmosphere or to flare) but on the compressor.

Response: Today’s final rule specifies that all compressor vents are to be measured. The rule does not require the optical gas imaging camera to be used on vents, as this is unnecessary. Compressor equipment leaks require leak detection and leaker emission factor. Please see response to comment EPA-HQ-OAR-2009-0923-0133-4.

Comment Number: EPA-HQ-OAR-2009-0923-1014-10
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
Large Compressor B1owdown Valve Leak & Large Compressor Blowdown
Vent (Unit Isolation Valve Leak)

Subpart W proposes to require operators to report emissions from large compressor blowdown valve leaks and large compressor blowdown vents (unit isolation valve leaks) using leak detection with an optical gas imaging instrument. Optical gas imaging equipment is very expensive (approximately $75,000-90,000 per camera) and may prove highly burdensome and cost-prohibitive for many operators-and particularly smaller companies-to obtain. Such an expense is particularly unreasonable if operators will be required to purchase such equipment just to make the initial applicability determination (before it is determined that monitoring and reporting under Subpart W is even required). While USEPA generally has assumed that companies subject to the requirements of Subpart W will hire contractors to conduct much of the monitoring and data collection required under the proposal, such an assumption may not be valid in many cases (and, as noted above, IOGA-WV has concerns about the scant number of local and regional contractors that currently have the capabilities and expertise necessary to perform the analyses required by the proposed rule).

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-0049-7 and the preamble Section III.B. EPA has revised today's final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. Concerning the availability of equipment or trained operators, for certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1015-38
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Furthermore, in the Technical Support Document (pp. 28-29), the EPA states, "another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions." Many sources in a producing field (tanks, compressors, etc.) are located in extremely remote areas and are therefore, by most definitions, "inaccessible." Direct sampling of those field sources will include previously unscheduled trips of environmental staff which can take staff members off-site for days at a time, traveling in dangerous and remote areas throughout the course of the year. Direct sampling of these sources is not only burdensome on staff, it is dangerous for minimal benefit when emission factors could be developed for such sources.
Companies will most likely rely on 3rd parties to conduct most direct measurement samples. PAW requests guidance from the EPA on how to reasonably work with 3rd party vendors to ensure their sampling methodologies meet EPA requirements.

Response: EPA recognizes the importance of ensuring safety, and has added alternative methodologies to ensure safety. Please see response to comment EPA-HQ-OAR-2009-0923-1024-11. EPA has revised several methodologies in today's final rule for onshore production to reduce burden. Please see the preamble Section II.F. It is the responsibility of the reporter to manage any third party vendors they may choose to contract for work. For further details on the role of the designated representative please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-1017-2
Organization:
Commenter: Michael James LeBrun

<u>Comment Excerpt Text:</u>
Recently we had a chance to look at a gas imaging camera made by FLIR. this [*sic*] model is the GS320. I fell in love with this camera and have used it in a number of operations. Where my gas sniffer increased a beeping tone to signify that gas was present, this camera lets you see a gas plume as clear as day, and the amount could be less than a lighters amount of gas leaking, this camera will find it. I have found a fair amount of leaks, small ones, but leaks on my equipment of any kind is saving my operators money, and is puitting [*sic*] a smile on Mother Nature's face!!! I can't stress enough that when you finalize this subpart w regulation, that somewhere in BIG LETTERS, let our industry know that there is this wonderful new gas leak finding camera made by FLIR, and a great service company called Western Thermal Imaging that has safe, confident, well dressed, and well versed people on the equipment that we are using to produce natural gas.

Response: EPA does not endorse technology vendors or service providers. Please see response to comment EPA-HQ-OAR-2009-0923-1039-18.

Comment Number: EPA-HQ-OAR-2009-0923-1018-38
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
98.233 (p):
In 98.233(p)(2)(ii) CAPP believes the use of an orifice meter is inappropriate in this application. A better meter for this application would be an appropriately sized rotameter, diaphragm meter or rotary meter (roots meter).

Response: The commenter has misinterpreted the rule. EPA does not require the use of an orifice meter for measurement of reciprocating compressor vents. EPA has not prescribed the type of meter that must be used. Please see response to comment EPA-HQ-OAR-2009-0923-1305-31.

Comment Number: EPA-HQ-OAR-2009-0923-1018-50
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.234 (c):
CAPP does not support the use of calibrated bags for all atmospheric emissions; the methodology described by the EPA in 98.234(c) is very onerous and is not practical for sources with many leak points or large surface areas such as compressor seal emissions.

Response: The commenter has misinterpreted the rule. The rule stipulates that calibrated bags may be used only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all of the emissions, so if a leak cannot be totally captured and sealed, then calibrated bags cannot be used for reporting under subpart W for that source.

Comment Number: EPA-HQ-OAR-2009-0923-1024-33
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Comments on the Proposed Monitoring and Quality Assurance / Quality Control Requirements. As noted above, Kinder Morgan urges EPA to allow other forms of emissions detection apart from optical imaging. The leak detection procedure in the proposed 40 C.F.R. SECTION 98.234(a) should be revised accordingly to accommodate appropriate standard leak detection methods.

In addition, Kinder Morgan believes that the proposed 40 C.F.R. SECTION 98.234(a)(1) has a grammatical error. The corrected provision should read “Use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 C.F.R. part 60, subpart A, SECTION 60.18(i)(1) and (2), of the Alternative work practice for monitoring equipment leaks.” Further, EPA should clarify leak detection frequency by stating that, when used, optical gas imaging would be performed on an annual basis.

Response: EPA has revised today’s final rule to allow specific alternative leak detection methods. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1039-18. EPA agrees that the proposed rule text be clarified. Please see the response to EPA-HQ-OAR-2009-0923-1039-31. The commenter has misinterpreted the rule. The rule states that annual leak detection surveys are required.

Comment Number: EPA-HQ-OAR-2009-0923-1026-10
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
Unit -specific Emissions Estimation Methodologies

The unit-specific emissions estimation methodologies rely on a combination of direct measurement and emissions factors. This approach must recognize that there are limitations of both methods. For emissions that are calculated based on emissions factors, most equations include operating hours; most components have no way to determine operating hours and must, therefore, assume 8,760 hours of operation per year, resulting in an artificially inflated inventory. Where direct measurement is required, again, if a component is found to be leaking, the reporting methods require that this emission rate is valid for the entire reporting period, when, in fact, leaks are normally repaired as soon as possible. EPA should evaluate the possibility of developing annual emission factors, rather than relying solely on hourly emission factors for non-combustion units. This would allow emissions to be calculated based on the percentage of time, i.e. days or months, that a facility operated annually rather than tracking operating hours for each individual piece of equipment

Response: Today's final rule has been revised to allow the option of performing multiple leak surveys. Please see the response to comment EPA-HQ-OAR-2009-0923-1014-9. EPA disagrees with the comment on emission factors. EPA's analysis of the methods used in subpart W is outlined in the April 2010 proposed rule's Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027). To provide the data quality necessary to inform policy, reporters must accurately determine the amount of time of emitting GHGs from each source.

Comment Number: EPA-HQ-OAR-2009-0923-1039-31
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
§98.234(a)(1) text clarification: The text in §98.234(a)(1) should be revised to read, "…§60.18(i)(1) and (2) of the Alternative Work Practice…".

Response: EPA agrees and today's final rule has clarified the text.

Comment Number: EPA-HQ-OAR-2009-0923-1042-22
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
§98.233(u) GHG volumetric emissions

ConocoPhillips Comment:

a.) §98.233(u) requires of onshore petroleum and natural gas production facilities quarterly sampling of natural gas for GHG content for the following categories: natural gas pneumatic high bleed device venting, natural gas pneumatic low bleed device venting, natural gas driven pneumatic pump venting, conventional and unconventional completions and workovers, reciprocating compressor rod packing venting, well testing venting and flaring, associated gas venting and flaring, acid gas removal vent, and centrifugal compressor wet seal degassing venting. §98.233(u)(2)(i) states that the quarterly gas samples must be collected using the methods set forth in §98.234(b). However, there are no such methods set forth in this paragraph. We request that EPA allow the use of any consensus based standard for collecting and analyzing the gas.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1305-31.

Comment Number: EPA-HQ-OAR-2009-0923-1045-2
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

Comment Excerpt Text:
Accessibility and Cost of OGI

Some of the comments already submitted on the proposed Subpart W have expressed concern about the availability and cost of OGI cameras. Accordingly, we thought it appropriate to provide some cost information so the discussion on this issue is informed with factual data.

A gas detection camera optimized for detecting methane and other VOCs currently costs approximately $85,000. Another $5,000 should be budgeted to accommodate the training necessary to make operators competent to find and document leaks in a variety of inspection scenarios. The costs of this system reflects the unique configuration of sensors that are necessary to reliably detect gaseous VOCs, including a specially filtered hypersensitive photovoltaic detector chilled to a temperature of -320˚F using a compact portable closed cycle cooling system. It is quite possible, however, that the camera pricing will decline as increased demand creates production efficiencies and broader adoption draws competitive suppliers into the business.

The Agency accurately points out that many facilities will not need to purchase a camera or train personnel, and will instead elect to use contractors who have purchased the technology and have operators with certified training in the use of OGI. Fees charged by contractors for each day of data collection and reporting generally range from $2,000.00 per day to $5,000.00 per day. The comments below are typical of the feedback we are receiving from consultants who offer OGI contract services.

Typical fees are $3,500 per day (12hours of work or $291/hour) which covers all equipment and crew. Additional charges for reporting would add roughly $500. Travel expenses are additive to these fees and will vary depending on the ability to access facilities without plane travel or hotel stays.

The average gas plant takes between 0.5 to 1 day (depending on how many emissions are found). Note, the EPA threshold of 25,000 tons CO2e/year would be considered an average sized to small gas plant which would be about 0.5 days or approx $2,250. Large gas plants (approx 230,000 CO2e per year) can be completed in 1.5 days and (approx. 240,000 CO2e/year) in 2 days. Very large gas plants in the range of 350,000 tons CO2e per year with numerous leak locations can take as long as 3 day.

FLIR Systems believes that sufficient equipment and trained personnel can be made available to meet the demand from petroleum and natural gas systems once monitoring requirements take effect in 2011. There are approximately 500 OGI cameras now in service, with approximately 100 additional cameras deployed each year. Contractor services are widely available, with approximately ten companies in the field now using highly sensitive OGI technology to detect methane and VOCs. Given that optical imaging surveys need only be taken once a year under the proposed Subpart W, FLIR Systems believes that there is adequate time over the coming year for the OGI industry to meet the needs of companies subject to Subpart W.

We have spoken to most of the consultants using FLIR System OGI cameras, and they indicate it would not be difficult to scale up their operations with additional equipment and trained operators. Once a service organization has invested in the infrastructure necessary to support the development of service packages, reporting systems, administration and billing and the marketing materials necessary to support the service, it is not difficult to add cameras and operators. Organizations who already offer OGI are typically in the best position to quickly add competent technicians since they may have labor resources from other diagnostic services that can be formally trained in OGI. New camera operators will then quickly develop competency when formal training is augmented by in-field training and insights from trained OGI technicians.

FLIR Systems manufactures the key camera components, including the detector, read-out integrated circuits, and cryogenic coolers necessary to build the OGI cameras. FLIR Systems can scale up production quickly to meet any increase in demand

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1045-1.

Comment Number: EPA-HQ-OAR-2009-0923-1045-5
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

Comment Excerpt Text:
Other commenters correctly point out that the preamble does refer to "customer meters used to transport natural gas primarily from high pressure transmission pipelines to end users."[180] It is important to clarify which metered end-customers, if any, will qualify for OGI under the proposal. We would recommend that all industrial users with metering and regulation and direct connections to transmission lines be included. Assuming that any customers covered by Subpart W would be larger consumers, we estimate that there would be between 2 and 25 customers in a utility like the one surveyed.

Response: EPA has clarified today's final rule and does not include customer meters. Please see the preamble Section II.F.

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[180] 75 Fed. Reg. at 18,617.

Comment Number: EPA-HQ-OAR-2009-0923-1045-6
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

Comment Excerpt Text:
Recommended Phase-In of Certain Underground Pipelines. Although EPA suggests in the preamble to the proposed Subpart W that underground pipeline fugitive emissions cannot be detected using OGI, we have some experience with pipeline inspection and the link below provides an example of how a gas leak can be detected as it leaks through a manhole cover in downtown Boston.

(http://www.flir.com/thermography/americas/us/OGI/naturalgas/)

This example clearly illustrates that OGI is capable of finding leaks emanating from belowground pipelines.

Thus, we suggest that EPA consider a "phase-in" period for use of OGI as a tool for detecting leaks from underground pipelines. A phase-in would be appropriate for two reasons. First, this application is the most challenging for OGI. We have found the cameras we deploy for this application need to engage a special "high sensitivity mode" to detect gas that may be leaking up through pavement.

Second, we feel it is premature to require LDCs to use OGI to detect pipeline leaks until more field work has been completed on OGI applications for pipeline leak detection. We believe that periodic scanning of manhole covers and other areas may prove effective, but believe that a year of experience deploying OGI in the LDC targets sited in the table above would be advisable before specific recommendations on work practices can be formulated and incorporated into training programs.

Response: EPA disagrees with leak detection of pipelines for today's final rule. EPA's analysis of pipeline emissions quantification methods is outlined in the Technical Support Document (TSD) for the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0027), and in the April 2010 preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1045-8
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

Comment Excerpt Text:
OGI Sensitivity Thresholds and Performance Standards

The sensitivity thresholds described in 40 CFR part 60 subpart A §(i)(1) and (2) require an OGI camera to detect a methane leak of 60 grams per hour. Contrary to EPA's discussion of the AWP sensitivity threshold, we have found cameras with this sensitivity level to be suboptimal for OGI.

The cameras utilized today by the natural gas and petroleum sectors, and the cameras produced for OGI by our company, are able to clearly detect a leak rate of 1 gram per hour of methane or less. We are not aware of any gas company, petrochemical company or consulting services company currently using an OGI camera that does not perform to this standard.

Although our company also manufactures lower performance infrared cameras, that are sensitive in the 60 grams per hour range, we note that cameras operating at this sensitivity level may be effective in controlled environments but, are highly susceptible to adverse environmental conditions or operator error. Field dynamics – which may include significant wind currents, varying thermal background conditions and the degree of operator proficiency – do not make these cameras the best option for OGI.

We believe that EPA's reference to the Alternative Work Practice could encourage the use of infrared cameras that are unable to find leaks in a real world outdoor application. We encourage the EPA to modify the sensitivity threshold to a level consistent with field validated performance thresholds to a leak rate of 1 gram per hour of methane or less.

Response: EPA disagrees with this comment. Please see EPA's analysis of the optical gas imaging instrument in EPA's preamble to the Alternative Work Practice to Method 21, and in docket EPA–HQ-OAR-2003-0199-0005.

Comment Number: EPA-HQ-OAR-2009-0923-1060-12
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Use of Direct Measurement

On page 18611 of the pre-amble, the EPA states, "In this supplemental proposal, EPA is requiring the use of direct measurement of emissions for only the most significant emissions sources where other options are not available, and proposing the use of engineering estimates, emission modeling software, and leak detection and publicly available emission factors for most other vented and fugitive sources." We disagree that the EPA is requiring use of direct measurement of emissions "for only the most significant emissions sources where other options are not available." Direct measurement is required for transmission tanks, wet seal degassing, reciprocating rod packing venting, flare stacks. Requiring direct measurement of transmission tanks, wet seal degassing and reciprocating rod packing venting will require field personnel to visit each site to determine which sources must be reported, and to measure each of those sources. Yates Petroleum Corporation, and its subsidiaries, is responsible for nearly 4,000 well sites and hundreds of miles of pipeline. Sending staff to even a portion of these sites will result in emissions from vehicles, wear and tear on equipment, and valuable time lost by staff in the field - none of which appears to have been taken into consideration when calculating the cost of implementing this rule.

Yates requests that EPA reconsider the use of direct measurement for these sources after one year. If these sources are less than 5% (in alignment with The Climate Registry's deminimus emissions) of the total GHG emissions after the first reporting year, Yates recommends that EPA propose emission factors and assumptions as an alternative to direct measurement.

Furthermore, in the Technical Support Document (pp. 28-29), the EPA states, “another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions.” Many sources in a producing field (tanks, compressors, etc.) are located in extremely remote areas and are therefore, by most definitions, “inaccessible.” Direct sampling of those field sources will include previously unscheduled trips of environmental staff which can take staff members off-site for days at a time, traveling in dangerous and remote areas throughout the course of the year. Direct sampling of these sources is not only burdensome on our staff, it is dangerous for minimal benefit when emission factors could be developed for such sources.

Lastly, Yates will rely on 3rd parties to conduct most direct measurement samples. Yates requests guidance from the EPA on how to reasonably work with 3rd party vendors to ensure their sampling methodologies meet EPA requirements.

Response: EPA disagrees with this comment. Please see response to comments EPA-HQ-OAR-2009-0923-1060-1 and EPA-HQ-OAR-2009-0923-1015-1. In addition, it is the responsibility of the reporter to manage any third party vendors they may choose to contract for work. The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today’s final Rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-1074-11
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
75 FR 18620: 1. Direct Measurement

Comment: WBIH recommends limiting the direct measurement of storage tanks at onshore natural gas transmission compressor station facilities to condensate storage tanks.

EPA stated, "For example, storage tanks in the onshore natural gas transmission segment typically store the condensate (water, light hydrocarbons, seal oil) from the scrubbing of pipeline quality gas. The volume and composition of liquid is typically low and variable, respectively, in comparison of hydrocarbon liquids stored in the upstream segment of the industry. Hence the emissions from condensate itself in the transmission segment are considered insignificant."

Response: EPA has clarified today’s final rule to state that in regard to tank emissions, only transmission condensate storage tanks require monitoring. Please see the response to comment EPA-HQ-OAR-2009-0923-1039-20.

Comment Number: EPA-HQ-OAR-2009-0923-1074-2
Organization: WBI HOLDINGS

Commenter:

Comment Excerpt Text:
75 FR 18612: A. Overview of Proposal, Amendments to the General Provisions

Comment: WBIH recommends the use of direct measurement on manifolded vent lines, existing and newly constructed, in response to this measurement option, as an optional monitoring method for emissions quantification for storage tanks at onshore petroleum and natural gas production facilities.

E&P Tanks is best suited for upstream operations, and for data accuracy, the program requires site-specific information to determine emission rates. The E&P TANK model allows the user to input compositional analyses from pressurized oil and gas samples to simulate flash generation in storage tanks. Specifically, the minimum inputs needed for the model are: separator oil composition; separator temperature and pressure; sales oil API gravity and Reid Vapor Pressure (RVP); sales oil production rate; and ambient temperature and pressure. Since separator oil composition is a key input in the model, E&P TANK includes a detailed sampling-and-analysis protocol for separator oil. This will require additional costs associated with the required sampling. Additionally, E&P Tanks is not "available for free" as stated in the Preamble (Section 1I.E.1 (2)). There is a cost of approximately $500 per copy (single-user or single computer software) for API nonmembers.

There is much on-going discussion in the oil and gas industry about E&P Tanks and the resulting emissions estimates. When using other emissions estimation models or calculations, such as Vasquez Beggs Equation, gas-oil ratio (GOR) and throughput of hydrocarbons, and process simulators (i.e. HYSIM, HYSYS, etc.), there is wide range of emission estimation results, with the highest estimate being on the order of magnitude three times the lowest estimate.

Response: Please see response to comments EPA-HQ-OAR-2009-0923-1074-34 and EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1082-18
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
EPA seeks comment on whether this alternative approach better estimates annual facility emissions without resulting in additional reporting burden to the facilities. (page 78)

Detecting, quantifying and repairing small leaks should require minimal burdens, where as detecting, quantifying and repairing larger leaks should have burdens commensurate with the leak volume. If larger leaks are present, operators will already have a financial and safety-based incentive to repair them. The alternative approach is preferred.

Response: EPA will allow multiple leak detection surveys. Please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1082-5
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
It is important to allow for flexibility in calculating and reporting of greenhouse gas emissions for natural gas systems given the nature of such systems. As evidenced by MidAmerican's experience in California, a one-size-fits-all approach to reporting greenhouse gas emissions, even in a specific industry sector, does not work well. Establishment within the regulation of default emission factors that overstate emissions without the ability to utilize approved alternatives does not advance accuracy in measurement and reporting. Having to obtain individual variances or approvals due to differing circumstances consumes agency and company resources and skews public perceptions on emissions. EPA should ensure that reporting entities adhere to recognized protocols that will produce reasonably accurate emissions data rather than prescribing precise methodologies within the rules themselves.

There are circumstances when differing approaches should be applied to account for greenhouse gas emissions. For example, for larger leaks in natural gas pipeline operations it is appropriate to use direct measurement techniques to account for emissions. However, for leaks from minor/smaller components the use of analytical methods and emission factors are more appropriate. It is important to give businesses flexibility in selecting the most appropriate detection and measuring approach to ensure accuracy.

Response: EPA disagrees with the comment that EPA should allow reporters to choose methods that are not specified in subpart W. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section L. EPA's analysis of methods is outlined in the Technical Support Document (TSD) for the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0027).

Comment Number: EPA-HQ-OAR-2009-0923-1099-19
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Monitoring methods and emissions quantification for: Fugitive emissions from onshore natural gas transmission compression
NMGC appreciates that EPA revised Subpart W so that it no longer requires leak detection of all the 24 originally listed sources and has allowed engineering estimation or component counts to calculate emissions for several sources. EPA also reduced the number of sources for which a leak detection survey is required to identify emissions which reduces our burden. However, the new Subpart W is still labor intensive and in some cases not even possible to calculate using the proposed methods.

Response: EPA disagrees with the comment on burden. Please see response to comment EPA-HQ-OAR-2009-0923-1099-8 and the preamble Section III.B. The commenter did not provide sufficient details as to what calculations may be difficult.

Comment Number: EPA-HQ-OAR-2009-0923-1151-59
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.234(d)(2). The protocol directs the technician to use "anti-static wraps or other aids" if the high volume sampler is not able to completely capture all emissions from the source, but does not specify how such leakage is to be detected or how these aids are to be used.

Response: The commenter has misinterpreted the rule. The rule prescribes that the manufacturer's operating parameters must be followed when operating the leak detection or measurement equipment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-88
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Paragraph 98.234(1) should be revised to include the phrase "of the" in the first sentence ("in accordance with 40 CFR part 60, subpart A Section 60.18(i)(1) and (2) of the Alternative work ...") and to delete the word "proposed" in the last sentence ("you must operate the optical gas imaging instrument to image the source types required by this proposed reporting rule...").

Response: EPA has clarified today's final rule text. Please see the response to comment EPA-HQ-OAR-2009-0923-1039-31. EPA has also replaced "proposed reporting rule" with the word "subpart" in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1155-22
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Fugitive and Vented Emissions

We support EPA's proposed fugitive and vented emission estimating methods that rely on a combination of leak detection, population count and emission factors. We agree that the methods proposed are conservative and may tend to overestimate emissions, because the methods assume that whenever a leak is found it occurred for the entire annual reporting period.

As an alternative, EPA could provide the option for Operators to more accurately estimate emissions using direct measurement and detailed leak repair reporting methods, where the

Operator can quantify the leak rate, make repairs to stop the leak, and only report emissions for the period of time that the leak actually occurred, rather than assuming the leak continued for the entire reporting period.

We do not support EPA's proposal to exclude fugitive emissions from natural gas pipeline segments between compressor stations, crude oil pipelines, and tank terminals. EPA has proposed this exemption based on the assumption that fugitive emission leaks are repaired, whenever found in this industry sector.

This assumption is not always true, and therefore, we request that these fugitive emission sources be included in the MRR.

Response: EPA disagrees with the comment on direct measurement. Please see the response to comment EPA-HQ-OAR-2009-0923-1155-12. EPA disagrees with the commenter regarding onshore natural gas transmission pipelines, crude oil pipelines and tank terminals. EPA's analysis is outlined in the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) and the April 2010 preamble Section II.C.

Comment Number: EPA-HQ-OAR-2009-0923-1196-6
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

<u>Comment Excerpt Text:</u>
In the 2009 EPA proposed reporting requirements, the EPA limited the reporting threshold to 25,000 metric tons/year per facility based on the cost effectiveness test to capture most of the GHG emissions while limiting excessive costs. However, according to IPAA analysis, this proposal will result in 43% of the capital costs to comply will be by the petroleum and natural gas industry to report an estimated 3% of the nation's emissions. While EPA contends that it underestimated the amount of GHG emissions, IPANM would strenuously object to the use of any data from the New Mexico Environment Department as a basis for emissions in the State. The Department has admitted to difficulty in collections and reporting due to staffing and consulting conflicts which resulted in incomplete figures submitted to meet a deadline for a Governor's taskforce on climate change. While there has been an additional report since the first submission, the scientific basis for the NMED numbers have not been submitted to industry for review or discussion.

Response: EPA disagrees that petroleum and natural gas systems account for only 3% of greenhouse gas emissions. Please see response to comment EPA-HQ-OAR-2009-0923-1005-6. EPA disagrees with the comment on costs. Please see the Economic Impact Analysis Section 5. The commenter is not clear as to what data sources they claim EPA used that may be from the NMED. The sources used for estimating emissions for the threshold analysis are outlined in the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923)

Comment Number: EPA-HQ-OAR-2009-0923-1200-6
Organization: The Dow Chemical Company
Commenter: Robert Rouse

Comment Excerpt Text:
EPA Should Clarify that 40 CFR 98.233(p)(3) has Two Options vs. One.

Dow comments that it appears that there should be an "or" inserted between the regulatory text in proposed 98.233(p)(3)(i) and (p)(3)(ii) as the first paragraph calls for the use of an optical gas imaging instrument and the second paragraph calls for direct measurement of the emissions using a high flow sampler or a calibrated bag. It appears that these two paragraphs are independent options, thus an "or" should be inserted between them.

Response: The commenter has misinterpreted the rule. EPA disagrees that an "or" should be inserted between the leak detection and leak measurement paragraphs in the monitoring description for reciprocating compressors. The leak detection in the first paragraph is to identify equipment leaks; the second paragraph is to measure those identified leaking emissions. Both are required for compliance with subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1206-4
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Second, the proposal would impose detailed emissions estimating and measurement requirements that will be far more costly than EPA predicts and would produce information that is no more useful to the Agency than information that could be gathered in significantly less prescriptive and costly ways. For example, emissions from all tanks must be calculated, even tanks that have small throughput and, therefore, nominal emissions. Similarly, although direct measurement is required for only a few source types, the testing would be prohibitively expensive and would produce information that is of questionable validity given that it would Air and Radiation Docket and Information Center represent only a point in time, which does not necessarily shed light on performance over an entire year.

Response: Today's final rule requires direct measurement for sources that are determined to have large uncertainty, and for which all other methods significantly underestimate emissions. EPA requires such direct measurement to produce the necessary data quality to inform future policy. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA has revised several of the monitoring methods in today's final rule to reduce burden. Please see the preamble Section II.F. EPA disagrees with the comment on costs. Please see the Economic Impact Analysis Section 5.

Comment Number: EPA-HQ-OAR-2009-0923-1299-14
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:

Offshore LNG facilities consist of the LNG carrier with its integral LNG tanks, pumps, and vaporizers, and the mooring and sendout buoy and underwater pipeline. As is true for onshore facilities, specialized installed equipment is designed, operated, and maintained to contain the fluid; installed detection monitors each area and alarms if an emission is detected; personnel inspect and control the processes and will immediately stop an operation in the event of a leak, to protect the carrier's structures from the cryogenic fluid; and emergency shutdown valves provide ultimate control to stop the process. Each ship moors for only long enough to vaporize and offload its cargo. The facility operates only when an LNG carrier is at the deepwater port. Accordingly, the requirement for annual leak detection would be inapplicable. Further, the U.S. Coast Guard thoroughly inspects the safety systems of each vessel upon each arrival, and would prevent mooring, or stop an offloading, in the event of a deficiency or leak.

Response: EPA disagrees with the comment, and is including the LNG facilities in today's final rule. Please see the response to comment EPA-HQ-OAR-2009-0923-1025-1 and EPA-HQ-OAR-2009-0923-1151-130.

Comment Number: EPA-HQ-OAR-2009-0923-1299-3
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:

Leak Detection and Reporting

The proposal for leak detection and reporting would impose significant additional costs – and would result in an overstatement of the actual level of facility emissions. The proposed rule would require utilities to conduct annual leak detection at above grade M&R stations and to NGA Comments on EPA Subpart apply emission factors to the leaking sources. While current practices require regular leak detection, and effective methods such as bubble testing are used, the proposal specifies optical imaging, a method that appears to be less accurate. Optical imaging requires expensive monitoring equipment, significant time for conducting measurements in the field, and extensive recordkeeping. (On the other hand, current methods using soap solutions, although not quantified, are accurate in pinpointing leaks. The simplicity of this method allows all field personnel to find and fix leaks immediately.) A simple and effective method should be the preferred choice. We believe that the value of optical imaging needs to be demonstrated and defined before any mandate is imposed.

Response: EPA disagrees with the comment on cost. Please see response to comment EPA-HQ-OAR-2009-0923-1299-18 and the preamble Section III.B. EPA has revised today's final rule and will allow specific additional leak detection methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1299-4
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:
We also question whether there would be enough equipment or trained operators to conduct such annual surveys at all the M&R stations that would be affected. Also, when utilities conduct leak detection, they promptly repair leaks that can be readily repaired. Reporting the repaired components as if they were leaking for the entire year will overstate actual emissions. We would respectfully ask that EPA first investigate the accuracy of such programs in terms of the methodology for emissions quantification before imposing and implementing this procedure, and also undertake a comparative assessment of other existing programs and methods to determine if there is a more accurate and cost-effective alternative.

Response: Concerning the availability of equipment or trained operators, for certain sources EPA will allow the application for the use of best available monitoring methods. Please see the preamble Section II.F. EPA has revised today's final rule to include multiple leak detection surveys to account for repairs. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9. Regarding the comment on assessment of alternative programs, EPA detailed its research into the prescribed methodologies and alternatives for all sources. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1306-21
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
As noted by the EPA, the natural gas industry is taking a proactive role in identifying natural gas leaks and then repairing the identified leaks. As a result of the extra leak detection imposed by this rule, further leak repairs will be performed. DTE Energy supports calculating emissions in which the leak time is measured from the time the leak was identified to when the leak was repaired, or to the end of the year. This will give a more accurate quantification of fugitive emissions that factor in the reductions resulting from leak repairs.

Response: EPA has revised today's final rule to include multiple leak detection surveys to account for repairs. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-0582-23
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Measurement Options: Three emissions quantification options were evaluated. These options are shown below.

Option	Pros	Cons
1) Engineering Calculations, Metering where available Determine fuel consumption using either installed gas meters (where available) or engineering calculation where metered data is not available. Measure field gas composition periodically. Calculate emissions from fuel use and carbon content.	Simplest approach requiring no installation of meters. Engine run-time meters may be required for engineering calculation.	Data quality and consistency will vary within a reporting entity and across reporters. US data may not be as high quality as Canadian data where there are regulatory requirements to quantify field gas consumption. Issues of consistency and questions concerning the accuracy of engineering approaches suggest that data derived using this approach would not be of sufficient quality for cap-and-trade.
2) Metering required for significant fraction of fuel use, remainder by engineering calculations Meter a significant fraction of	More accurate method which would generate more consistent data both for individual reporters and for all reporters.	Requires the upfront installation of meters on the larger engines. Prior to the beginning of reporting period it may be difficult to determine which engines require

Option	Pros	Cons
field gas consumption Estimate remaining field gas consumption using an engineering method Determine field gas composition periodically Calculate emissions	Provides more consistent data quality between jurisdictions (US and Canada). WCI could require determination of fuel flow for a subset of metered engines using the engineering approach. This would allow evaluation of the engineering approach to fuel consumption determination.	metering. Engine changes during the reporting period would also complicate this approach.
2a) Metering thresholds as capacity, by device type **Year One:** Meter all compressors > 150hp Meter all heater-treaters > 200MBtu/hr Meter all heaters > 200MBtu/hr Meter all additional devices >200MBtu/hr (e.g. dehydrators) **Subsequent Years:** Meter all compressors >50hp Meter all heater-treaters > 50MBtu/hr Meter all heaters > 50MBtu/yr Meter all additional devices >50MBtu/hr	Phased-in metering requirement allows time for installation. Clear thresholds based on readily available information.	Complex application to installations with a mixture of above- and below-threshold equipment.
2b) Metering threshold for installation-level field gas combustion equipment capacity	Phased-in metering requirement allows time for installation. Only one meter needed per	Installation-level capacity of field gas combustion equipment may vary above and below threshold during the year as equipment is added or removed.

Option	Pros	Cons
Year One: Meter all gas consumption > 1675 MBtu/hr **Subsequent Years:** Meter all gas consumption >525 MBtu/hr	installation if common-pipe metered.	

Discussion of measurement options:

3) Emission Factors.

In many cases manufacturers' data for equipment bleed rates is available. There are several issues which suggest that significant errors in estimated emissions may result when one uses OEM data. First, there is no industry standard concerning the reporting of instrument bleed rates and thus manufacturers report information in a wide range of units and under varying operating conditions. In addition the data reported by manufacturers has not been independently verified. USEPA has found large discrepancies between OEM bleed rate data and actual field data. Factors not reflected in available OEM data, such as gas pressure and maintenance history, significantly influence emissions rates. While the American Petroleum Institute API (2009) states that the use of manufactures' data is "the most rigorous approach" the Compendium also acknowledges that manufactures emission rates "tend to be lower than emissions observed."

Emission factors (EFs) for pneumatic devices have been developed. Many of these EFs were published in the 1997 GRI/USEPA Report, Methane Emissions from the Natural Gas Industry. The API Compendium compiles these and other EFs (see Table 5-15, pages 5-68 and 5-69) and estimates uncertainties in some cases. Where specified, reported uncertainties range from +/-33% to +/-407%. This indicates that use of EFs would result in very unreliable estimates of vented methane emissions.

4) Direct measurement:

Actual site specific measurement of vented emissions from low and high bleed pneumatic control devices is accepted to be an accurate method to quantify methane (and CO2 if present in the gas) emissions. One may characterize emissions from each pneumatic device at a facility using a bagging technique (or other method) where emissions from the device are captured and the volume of released gas is measured. Gas analysis then allows one to calculate actual CH_4 and CO_2 emissions. This technique is time consuming, labor intensive and expensive. In addition emissions may subsequently change as the result of factors such as maintenance activities and gas pressure changes, necessitating additional measurement.

5) Meter Instrument Gas Consumption:

Actual metering of instrument gas consumption and periodic measurement of gas composition will also provide an accurate determination of GHG emissions. Modifications to instrument gas plumbing and installation of one or more gas meters will be required initially and this will result in upfront material and labor costs. However, reporting in subsequent years will be very simple and easy, especially given the fact that periodic gas analysis will be required for other GHG emission calculations (e.g. stationary combustion emissions). In addition, changes in system operating conditions (e.g. line pressure, maintenance activities, instrument modifications) designed to reduce emissions will immediately be reflected in the volume of instrument gas consumed. Facility operators receive immediate feedback on their efforts to reduce emissions and can monitor instrument gas consumption in real time.

Response: EPA disagrees with the comments regarding direct measurement of pneumatic device venting or metering pneumatic device gas consumption. EPA reduced burden while maintaining the necessary data quality to inform future policy. EPA has revised the final rule to allow the use of emission factors for pneumatic devices and to allow reporters to complete a count of total pneumatic devices in three years, with best available data being acceptable for years one and two if the count is incomplete to reduce burden while maintaining the necessary data quality to inform future policy. Furthermore, EPA allows reporters to update the total count of pneumatic devices based on changes in the system beyond year three of reporting. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-0055-11. EPA disagrees with frequent sampling of gas composition as this would create additional burden, please see the preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1011-18
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Proposed Rule Section 98.233(q)(3) Leak detection and leaker emission factors for Onshore natural gas transmission compression facilities.—El Paso requests confirmation from the EPA that there are no monitoring requirements for centrifugal compressor dry seals from units operated at natural gas transmission facilities.

Response: Reporters are to monitor emissions through the centrifugal compressor dry seal vent line under the source “centrifugal compressor venting”. Please see response to comment EPA-HQ-OAR-2009-0923-1011-46.

Comment Number: EPA-HQ-OAR-2009-0923-1019-3
Organization: Red Cedar Gathering
Commenter: Ethan W. Hinkley

<u>Comment Excerpt Text:</u>
Direct Measurement of Compressor Rod Packing

Under the proposed rule EPA is requiring direct measurement of reciprocating compressor rod packing and blowdown valves for three operating modes. One of these is for a compressor that is not-operating and depressurized. Requiring measurements for this mode will require unnecessary down-time, loss of revenue, and unnecessary emissions being vented to atmosphere for the purpose of quantifying an insignificant source of emissions. When a compressor is not operating the unit is isolated from the gas flow, therefore no gas will flow to the rod packing and blowdown valves. Other emission regulations under the Clean Air Act specifically state that it is not required to start an engine solely for the purpose of conducting an emission test, nor should it be required to shutdown, and blowdown, and engine solely for the purpose of conducting an emission test. Red Cedar strongly recommends that EPA remove the requirement for leak detection and measurement for compressors in a non-operating, depressurized mode.

Response: EPA does not require the shutdown of compressors to collect data required under subpart W. Please see Section II.F of the preamble to today's final rule. EPA has revised today's final rule to allow compressor venting measurement in the 'as found' mode and that shutdown depressurized mode must be measured at least once every three years for each compressor. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1080-25
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Aka recommends that the reporting requirement, (98.236(c)(18)(i)) to measure throughput for each compressor be deleted. Alternatively, if EPA determines that compressor throughput is needed, that information should be provided on a per facility basis (i.e., as an aggregate for all compressor at a given facility rather than for each compressor individually) and throughput should be based on engineering estimates rather than direct measurement.

Response: EPA disagrees that average annual compressor throughput should be eliminated. Please see the response to comment EPA-HQ-OAR-2009-0923-1039-22. EPA has clarified that compressor throughput meters are not required, only annual throughput using engineering estimation based on best available data. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1298-40
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
There is an important inconsistency between the preamble and the proposed rule text. The preamble addresses monitoring methods and emissions quantification for large compressors (see Table W-4). In contrast, the proposed rule text would encompass all reciprocating compressors, regardless of size. IPAMS requests that EPA modify the rule to be consistent with the stated intent in the preamble by stating that emissions should be reported only for large compressors, which should be defined as compressors of 2,000 hp or more.

Response: EPA considered these comments, and has revised the rule to allow in onshore production for both reciprocating and centrifugal compressors, that population emission factors can be used. Please see response to comment EPA-HQ-OAR-2009-0923-1063-1.

Comment Number: EPA-HQ-OAR-2009-0923-1155-29
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Best Available Monitoring Methods

We agree with EPA's proposed decision not to allow the use of best available monitoring methods for part or all of the first year of data collection. EPA has already failed to issue timely final greenhouse gas reporting requirements for petroleum and natural gas systems as prescribed by Congress, and these facilities should be required to promptly and fully comply with the monitoring methods established under the proposed rule.

Response: EPA disagrees with the comment regarding not allowing best available monitoring methods. Please see the preamble Section II. F.

Comment Number: EPA-HQ-OAR-2009-0923-1300-4
Organization: Texas Oil and Gas Association
Commenter: Deb Hastings

Comment Excerpt Text:
Implement a phased approach of the use of best available monitoring methods for source types requiring metered flow rates or monitored parameters.

Response: EPA disagrees with the comment regarding a phased approach for best available monitoring methods. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1305-3
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
To address the amount of work and resources necessary to implement the rule as proposed, EPA should:

* Enable the use of BAMM for source types requiring metered flow rates, extensive sampling, or monitored parameters for the initial year of 2011 along with provisions to request extensions of BAMM beyond the end of 2011. This is particularly important for a sector like oil and gas where operations are spread out over a basin and are not staffed at all times. Often there is little existing infrastructure at these disparate locations and systems for monitoring and gathering information will likely need to be implemented.

- In addition, given that many of the sources are relatively minor individually and can be grouped together for estimation purposes, several simplifications that do not overly compromise data quality are detailed later in these comments.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1306-20
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
Use of Best Available Monitoring Methods

EPA requested comments on the proposal on the use of Best Available Monitoring Methods (BAMM) for part or all of the first year of data collection. DTE Energy agrees that the BAMM methodology of Section 98.3(d) is not well suited for fugitive leak detection and measurement when the reporting company is only required to perform a single annual test. On the other hand, BAMM for fugitive leak detection and measurement may need to be available for the entire year and not just for a 3 month time period in order to meet monitoring and reporting requirements during the first year of implementation under a final rule.

DTE Energy is concerned that if optical imaging equipment remains the only allowed method for fugitive leak detection, there will not be enough leak detection equipment available in the first year. If a best faith effort was made to obtain the equipment and train staff to use the equipment, DTE Energy believes that flexibility should be allowed in completing first year leak detection and measurement requirements. Unlike requirements to install fuel flow meters (i.e., to comply with the General Stationary Fuel Combustion Sources requirements under Subpart C), companies may not know whether they will need extra time to complete the leak detection and monitoring requirements under Subpart W until a substantial part of the first year has passed. DTE Energy supports the utilization of BAMM for the entire first year for instances when companies can objectively show they made best faith efforts to complete the leak detection and measurement required under Subpart W. DTE Energy also believes that a BAMM time frame similar to that allowed under 98.3(d) should be allowed for the first three months of 2010 if any continuous measuring devices are required to be installed under Subpart W.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

12.2 FREQUENCY OF MONITORING

Comment Number: EMAIL-0001-10 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
Annual Reporting

What is the rationale for annual reporting when experience with the U.S. Inventory of GHG emissions show very gradually changes in the total inventory on a year to year basis? For instance, even with the recent recession total inventory was only down about 2 to 3%. Has EPA given any thought to whether the large financial burden on industry should be required each and every year when a biannual report could suffice?

Response: EPA has not changed the frequency of reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H.

Comment Number: EPA-HQ-OAR-2009-0923-1010-7
Organization: Oklahoma Independent Petroleum Association
Commenter: Burckhalter

Comment Excerpt Text:
Annual reports from small oil and gas businesses operating marginal wells are excessive. As previously stated, marginal wells are mature crude oil and natural gas producing properties that have lost their initial, high production rates and instead operate on the much lower, flat end of the natural production decline curve. Emissions from these types of wells will not change significantly from year to year. At a minimum, EPA should reconsider this requirement. We recommend reporting from small oil and gas operators operating marginal wells be no sooner than every 5 years.
Response: EPA has revised today's final rule monitoring requirements, decreasing the burden on small business. Please see the preamble Section III.D. EPA has not changed the frequency of reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H.

Comment Number: EPA-HQ-OAR-2009-0923-1015-36
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
General Comments – Natural Gas Composition and Sampling Frequency

In the Technical Support Document (Page 44), the EPA states that, "these gas composition estimates are assumed to be available with facilities. But this may or may not be a practical assumption. In the absence of gas composition, periodic measurement of the required gas composition for a speciation of natural gas mass emissions into CH_4 and CO_2 could be a potential option." For facilities required to monitor fuel, PAW has found that the content of natural gas remains relatively constant by producing field. It is unnecessary to sample gas semi-annually or for every site, as the content changes over years, not months – and largely not by basin. Monthly gas samples are taken in fields that are still under development until the field stabilizes. Once the field stabilizes, those samples are generally taken no more frequently than semi-annually. Once a wellhead stabilizes and is tied into a gathering system, it is not industry practice to sample the fuel more frequently than semi-annually.

PAW recommends that the EPA allow companies to collect representative gas samples by basin rather than site-by-site for sites required to do quarterly or semi-annual gas sampling as required by 98.233(d)(1) and 98.233(u)(2)(i).

Response: EPA agrees, and has revised today's final rule regarding onshore production gas composition data collection. Please see the preamble Section II.E and response to comment EPA-HQ-OAR-2009-0923-1060-11.

Comment Number: EPA-HQ-OAR-2009-0923-1018-40
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
In 98.233(p)(4) CAPP would like clarification on how often these measurements will be required. The emission flow rate will change as the packing wears. Implementing a representative testing program would produce a large data gathering and retention burden. Additionally CAPP requests that the EPA provide guidance on how to handle situations where the unit may only be down due to upset and there is insufficient time to organize and conduct the required measurements.

Response: EPA has revised today's final rule regarding compressor monitoring. Please see the preamble Section II.F and response to comment EPA-HQ-OAR-2009-0923-1011-44.

Comment Number: EPA-HQ-OAR-2009-0923-1042-23
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
For venting not associated with well work (i.e., compressor rod packing, compressor wet seals, pneumatic devices and pumps, amine unit stacks), quarterly sampling will produce little to no variability in the results when the source of gas is the same reservoir from quarter to quarter. We thus request the option to perform the sampling every two years consistent with other sections of the rule (e.g., §98.233(f)(1)(i)(C)).

Response: EPA has revised today's final rule to allow the gas analysis for produced gas in 98.233(u) to use the reporter's most recent gas composition based on available sample analysis of the field. Please see the preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1058-3
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
A second concern is the frequency of the sampling of emissions which we believe is redundant, costly, and adds little new data in the calculation of the emissions.

Response: EPA has revised today's final rule regarding onshore production gas composition data collection. Please see the preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1074-17
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
WBIH recommends language which provides the ability to cease leak surveys or reduce the frequency of leak surveys.

The proposed rule does not have any language to reduce or cease leak surveys.
Annual leak surveys should be phased-out as improved equipment- or component based emission factors are developed and data accuracy objectives are met.

Response: EPA disagrees with less than annual reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H. EPA has provided provisions for facilities to cease reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H.

Comment Number: EPA-HQ-OAR-2009-0923-1082-17
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
EPA seeks comments on whether, if implemented, multiple surveys should be optional or required for owners or operators. (page 78)

Companies should be required at a maximum to conduct one annual survey. Alternative less frequent surveys should be considered based on the greenhouse gas leakage frequency and rate as documented by the company for each facility.

Response: EPA disagrees and requires at least an annual survey, but will allow multiple leak detection surveys. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9. EPA disagrees with less than annual reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H.

Comment Number: EPA-HQ-OAR-2009-0923-1099-22
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Frequency of the leak survey (page 18623)
NMGC feels the leak survey, if required, should be conducted annually as proposed in the rule. However, the rule should allow a company to voluntarily conduct surveys on a more frequent basis in order to be able to report emissions from a shorter time period than a year.

Response: EPA will allow multiple leak detection surveys. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1151-38
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(k) Transmission storage tanks. Section 98.233(k)(1) and (2) requires the flow rate of vented emissions from transmission storage tanks in onshore natural gas transmission compression facilities where the vapors are not routed to a vapor recovery or a thermal control device to be determined using either optical imaging or, if the vapors are continuous, a flow meter. Section 98.233(k)(3) specifies how to calculate emissions where the vapor is sent to a flare. Section 98.233(k)(1) refers to Section 98.234(a)(1) for how the optical gas imagining is to be conducted. Section 98.234(a) says "You must use the method described as follow to conduct annual leak detection of fugitive emissions from all source types listed in Section 98.233(p)(3)(i) and (q)…" Neither Section 98.233(k)(1) or Section 98.234(a) indicates the frequency for performing the optical gas imaging for transmission storage tanks. API assumes the optical gas imaging is to be performed annually and not every time there is a release from the scrubber dump valve. EPA should clarify the frequency in the rule.

Response: EPA has clarified today's final rule that transmission storage tanks are to be monitored only once annually. Please see response to comment EPA-HQ-OAR-0923-2009-1024-30.

Comment Number: EPA-HQ-OAR-2009-0923-1151-75
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
W14. (Preamble pp. 77-78) EPA considered, but did not propose, requiring a facility to conduct multiple surveys and to report emissions using the appropriate leaker factors. EPA seeks comment on whether this alternative approach better estimates annual facility emissions without resulting in additional reporting burden to the facilities. Further, we seek comment on whether, if implemented, multiple surveys should be optional or required for owners or operators.

API is not in favor of mandating multiple surveys, as this will result in an excessive burden. However, a reporter should have the option of utilizing data from multiple surveys, if data are available.

Response: EPA will allow multiple leak detection surveys. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1155-21
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Flare Emissions

We recommend that all gas that is routed to flare devices be metered. We agree with WCI's recommendation to increase the frequency of gas composition sampling, creating more accurate emission estimates.

Response: EPA disagrees that all gas that is routed to flare devices must be metered, as this data quality is not necessary to inform future policy, and would create additional burden. EPA disagrees with the comment on gas composition sampling. Please see response to comment EPA-HQ-OAR-2009-0923-1042-23.

Comment Number: EPA-HQ-OAR-2009-0923-1167-21
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Reduced frequency of measurements or process sampling, especially for invariant parameters. Quarterly sampling is required for numerous parameters such as field gas, AGR process gases, and hydrocarbon and water storage tank liquids. EPA has not provided or supported the technical basis for requiring this frequency. In addition, the costs are excessive as demonstrated above and should be reduced to an annual basis or less.

Data gathered as part of this process should inform the correct sample frequency over time and the sampling frequency should be relaxed when it is demonstrated that the process parameters are not significantly varying over time. For example, if two consecutive gas samples show that the composition is varying by less than a threshold (e.g. change in methane content and carbon content is less than 10%), then sampling should be relaxed to every other period and then to every fourth period and so forth unless consecutive samples exceed the threshold. For sampling and measurement activities required annually (e.g. separator oil and water samples for storage tank emission estimates), similar criteria to relax sampling to bi- or tri-annual should be instituted.

Response: EPA agrees and has revised today's final rule regarding onshore production gas composition data collection. Please see the preamble Section II.E. EPA has not changed the frequency of reporting. Please see The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) preamble Section II.H.

Comment Number: EPA-HQ-OAR-2009-0923-1167-7
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Reduced frequency of measurements or process sampling, especially for invariant parameters.

Response: EPA has revised today's final rule regarding onshore production gas composition data collection. Please see the preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-1206-56
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The section on GHG volumetric emissions generally requires the use of continuous gas analyzer or quarterly gas analysis for facilities operated by GPA member companies. There is no justification for quarterly gas analysis. An annual analysis would be sufficient.

Response: EPA agrees and has revised today's final rule regarding onshore production gas composition data collection. Please see the preamble Section II.E.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-6
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Also, when utilities conduct leak detection, they promptly repair leaks that can be readily repaired. So reporting the repaired components as if they were leaking for the entire year would end up overstating actual emissions. We're concerned about that as well.

Response: EPA will allow multiple leak detection surveys. Please see response to comment EPA-HQ-OAR-2009-0923-1014-9.

12.3 USE OF METHOD 21 DETECTION METHODS

Comment Number: EPA-HQ-OAR-2009-0923-1061-17
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

<u>Comment Excerpt Text:</u>
The monitoring methods specified in proposed § 98.234, "Monitoring and QA/QC Requirements," should be broadened. Section 98.234 would require the use of an Optical Gas Imaging Instrument for fugitive emissions detection on an annual basis. Essentially, this would involve screening equipment with an infrared camera to identify and count leaking components. Although useful for visualizing fugitive emissions, the cost of an infrared camera set up to visualize equipment leaks is high and training and expertise are required to optimize its use. Images may be affected by background, ambient temperature, and other factors, rendering the camera ineffective. Other methods are available for leak screening (e.g., acoustical instruments, soap bubbles, olfactory, audio, and visual means). A common method for monitoring fugitive organic emissions from leaking equipment is to employ a portable monitor using EPA's Method 21 for determination of volatile organic compound leaks. Generally, if a leak is detected, even with the optical monitor, a Method 21 monitor may be used and is often required for leak checking equipment after it is repaired under a Leak Detection and Repair Program. The use of an optical imaging instrument is offered as an Alternative Work Practice for Monitoring Equipment for leaks in 40 CFR Part 60, Subpart A, § 60.18(i)(I) and (2). Because other alternatives are available, the monitoring methods required under § 98.234 should be revised to include the use of Method 21 fugitive monitoring, especially if such a program is already in place and readily available.

Response: EPA agrees that specific alternatives to optical gas imaging cameras are acceptable for the purposes of leak detection for subpart W; please see Section II.F of the preamble.

12.4 USE OF BEST AVAILABLE INFORMATION

Comment Number: EPA-HQ-OAR-2009-0923-1031-6
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

<u>Comment Excerpt Text:</u>
The proposed effective date is impractical. It appears EPA is targeting publication of the finalized Subpart W in late 3rd quarter or early 4th quarter 2010, with an effective date of January 1, 2011. If the rule is finalized as proposed, there will be certain requirements (e.g., the acquisition and installation of certain monitors or information systems) that will not be practical to implement prior to January 1, 2011, and adequate time will not be allowed for the regulated community to do basic planning for implementation of the new rule. To alleviate such problems, Anadarko recommends EPA allow use of best available monitoring methods (“BAMM”) for emissions from calendar year 2011. Alternatively, EPA should develop a phased implementation schedule for Subpart W such that the effective date of Subpart W varies by industry segment, with segments with less burdensome requirements reporting sooner and those with greater burdens reporting later. We recommend that a three year phase-in period would be appropriate and that the upstream sector should be included in the last phase.

Response: EPA will allow the use of best available monitoring methods for some sources and is allowing some data to be developed over a three year period, but is not agreeing to an across the board phase-in period. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1151-64
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
(Preamble p. 23) EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenters recommend that EPA allow the use of best available monitoring methods for a designated time period (e.g., three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used.

A phased implementation of the rule over a period of several years will be necessary to fully understand the requirement of the rule, inventory all sources subject to the rule, and develop data collection systems, etc. to comply with the rule. Best available monitoring methods (BAMM) should be allowed where flow meters or pressure monitoring complying with Section 98.234(b) is required. The proposed compliance dates are unrealistic for the vast number of sources subject to Subpart W that have not been previously subject to regulatory reporting requirements. It is unreasonable to expect the regulated community to initiate procurement and installation of expensive monitoring equipment based on the proposed rulemaking. Regulated entities should be provided sufficient time between today's final rule (expected October 2010) and the implementation date for the required monitoring systems (January 1, 2011) to allow for detailed designing and engineering, equipment procurement, installation and calibration, personnel training, and systems integration. API recommends a phased in approach for monitoring systems where direct measurement is required similar to the provisions in Section 98.2(d).

Given the geographic dispersion of oil and gas facilities, installation of any additional equipment or monitors can be very challenging. Thus, API does not agree with EPA's comment in the preamble that "…the proposed monitors are widely available and are not time consuming to install." The inherent nature of the many unstaffed facilities would make installation and continued maintenance of any additional equipment arguably equally or more challenging for these facilities relative to a refinery or a chemical plant. API believes that a multi year BAMM approach is essential to a smooth implementation of this rule.

In addition, API is interpreting the rule to mean that any measurement that is to be collected at a frequency of once every two years must be collected by the end of the second year of the rule (December 31, 2012) to allow for the preparation of the 2012 report. If this interpretation is consistent with EPA's intent, API is fine with that the intent. If there is a requirement to have the monitoring completed sooner (i.e., December 31, 2011), then API would like to add that to the list of monitoring activities eligible for BAMM extensions.

Response: In developing the petroleum and natural gas sector initial implementation strategy, EPA considered using a phased-in approach. EPA determined that a blanket phased-in approach is not necessary because not every source will be too difficult to monitor in the first year of implementation. However, EPA considered that it may not be feasible for all reporting entities to fully comply with 2011 reporting requirements and therefore will allow the use of best available monitoring methods for certain sources. Please see the preamble Section II.F With regard to collecting data at a frequency of once every two years, it was not EPA's intent in the proposed rule to allow reporters to begin this cycle at the end of the second year. EPA requires that reporters collect this data such that it can be submitted in their 2011 report; today's final rule stipulates that data which is not collected annually must be collected in the first year. Please see today's final rule Section 98.233(f) and 98.233(g).

Comment Number: EPA-HQ-OAR-2009-0923-1024-5
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
To account for the short lead time and the limitations on availability of compliance resources, EPA should allow the use of "best available monitoring methods" for at least the first year of compliance with Subpart W.

Response: EPA will allow the use of best available monitoring methods in certain cases. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1024-52
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Additionally, consistent with our comments on the safety implications of Subpart W in Section II.A, Kinder Morgan recommends that EPA allow the use of an emission factor, emission rate, or other "best available monitoring method" for unsafe-to-monitor or difficult-to-monitor vents at reciprocating compressor rod packing venting. Facilities can use leak detection methods outlined in SECTION 98.234(a) to determine if the reciprocating compressor rod packing is venting. For those rod packings determined to be venting, emissions can be estimated utilizing an emission rate drawn from Natural Gas STAR databases or other appropriate sources.[181]

Response: Please see response to comment EPA-HQ-OAR-2009-0923-1024-11.

Comment Number: EPA-HQ-OAR-2009-0923-1040-9
Organization: American Exploration & Production Council

[181] A recommended emissions rate for reciprocating compressor rod packing venting is provided at EPA's Natural Gas STAR website at http://www.epa.gov/gasstar/tools/recommended.html.

Commenter: V. Bruce Thompson

Comment Excerpt Text:

The proposed effective date is impractical.

It appears EPA is targeting publication of the finalized Subpart W in late 3rd quarter or early 4th quarter 2010, with an effective date of January 1, 2011. If the rule is finalized as proposed, there will be certain requirements (e.g., the acquisition and installation of certain monitors or information systems) that will not be practical to implement prior to January 1, 2011, and adequate time will not be allowed for the regulated community to do basic planning for implementation of the new rule.

To alleviate such problems, AXPC recommends EPA allow use of best available monitoring methods ("BAMM") for emissions from calendar year 2011. Alternatively, EPA should develop a phased implementation schedule for Subpart W such that the effective date of Subpart W varies by industry segment, with segments with less burdensome requirements reporting sooner and those with greater burdens reporting later. We recommend that a three year phase-in period would be appropriate and that the upstream sector should be included in the last phase.

Response: EPA disagrees with the comment regarding a phased-in approach. However, EPA has determined that for specified emissions sources for certain industry segments, some reporters may need more time to comply with the monitoring and QA/QC requirements of Subpart W by January 1, 2011. EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1042-3
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:

To avoid the issue of an unreasonable schedule set in the 2009 final rule, at a minimum, EPA should allow the use of Best Available Monitoring Methods (BAMM) for 2011. In addition, BAMM should include cases where engineering calculations and/or emission factors are used to quantify emissions.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1042-6
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:

(Preamble p. 23) EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenters recommend that EPA allow the use of best available monitoring methods for a designated time period (e.g., three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used.

ConocoPhillips comment:

To address the unprecedented amount of work and resources necessary to implement the rule as proposed, ConocoPhillips requests the use of BAMM for at least the first year for several source types requiring metered flow rates or monitored parameters and for cases where engineering calculations and/or emission factors are used to quantify emissions. BAMM is particularly important for a sector like oil and gas. Unlike a chemical plant or a refinery, oil and gas operations are spread out over a basin and are often not staffed at all times. Thus, often there is little existing infrastructure at these disparate locations as opposed to a refinery or a plant. Therefore, the use of appropriate meters and the counting of pieces of equipment will be harder for these spread out oil and gas sources. Another very important point is that many companies will rely on contractors to carry out the work like optical imaging and quantifying emissions from equipment like compressor wet seals. There may not be a sufficient number of contractors to serve all the companies who will call on them in 2011 resulting in some companies facing potential compliance issues. For this reason, BAMM is very important in that it will allow industry to develop this resource for use in 2012.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1065-12
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Use of Best Available Monitoring Methods

The Clean Energy Group has concerns with the cost of implementing the proposed monitoring methods and the need to develop procedures and train staff, especially in the timeframe in which they are proposed to be implemented. Similar to the final mandatory reporting rule promulgated in October 2009, EPA could permit the use of best available monitoring methods for three months for parameters subject to direct measurement, and for fugitive leak detection. Alternatively, as noted above EPA could require simpler reporting methodologies for several years as it works with the industry to improve methods, and emission factors.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1065-7
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Allow the use of Best Available Monitoring Methods for the first quarter of 2011.

Response: EPA will allow the use of best available monitoring methods for some sources; please see the response to EPA-HQ-OAR-2009-0923-1151-64.

Comment Number: EPA-HQ-OAR-2009-0923-1167-23
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Best available methods currently employed by industry. EPA should provide for allowances to apply current industry standards or best practices. These include, but are not limited to: emission factors and estimation methods from the API Compendium or other GHG reporting reference documents, HYSIS and other process simulators, EPA and/or industry initiatives to collect data and develop better emission factors, and other industry standard approaches. Flexibility in selecting and applying emission estimation methods is discussed in greater detail in Comment IV. Industry has developed and used a multitude of emission estimation tools and methods to develop GHG emission inventories. Many of these are equivalent to or more rigorous than methods prescribed in the proposed rule. These methods should be allowed provided they are documented in the monitoring plan.

Response: EPA disagrees with the comment to allow reporters to choose methods not prescribed in the rule. Please see response to comment EPA-HQ-OAR-2009-0923-1151-9.

Comment Number: EPA-HQ-OAR-2009-0923-1167-29
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
To alleviate some of this burden, Noble recommends that emission estimation flexibility - that is, alternative “best available” emission estimation methods - be allowed. Although these methods may differ from those prescribed in Subpart W and Subpart C, their basis would be standard industry GHG protocols, such as the API Compendium, and company-specific data collection and engineering calculations developed for on-going annual inventory programs. To ensure data quality, the alternative methods would be documented in the Monitoring Plan.

Response: EPA disagrees with the comment to allow reporters to choose methods not prescribed in the rule. Please see response to comment EPA-HQ-OAR-2009-0923-1151-9.

Comment Number: EPA-HQ-OAR-2009-0923-1305-35
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Best Available Monitoring Methods

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

Best available monitoring methods (BAMM) should be allowed where flow meters or pressure monitoring complying with 98.234(b) is required. The proposed compliance dates are unrealistic for the vast number of sources subject to Subpart W that have not been previously subject to regulatory reporting requirements. It is unreasonable to expect the regulated community to initiate procurement and installation of expensive monitoring equipment based on the proposed rulemaking. Regulated entities should be provided sufficient time between the final rule (expected October 2010) and the implementation date for the required monitoring systems (January 1, 2011) to allow for detailed designing and engineering, equipment procurement, installation and calibration, personnel training, and systems integration. BP recommends a phased in approach for monitoring systems where direct measurement is required similar to the provisions in 98.2(d). BP recommends for Subpart W the BAMM special provisions in 98.2(d)(1) apply through all of 2011 with the ability to apply for an extension to use BAMM for a longer period according to 98.2(d)(2).

In addition, where the installation of required metering and/or monitoring equipment would require a shut down of a facility or unit BAMM should be allowed until the next scheduled shutdown where the equipment could be installed.

Given the spread out nature of oil and gas facilities, installation of any additional equipment or monitors can be very challenging. Thus, BP does not agree with EPA's comment in the preamble that "…the proposed monitors are widely available and are not time consuming to install." The inherent nature of the many unstaffed facilities would make installation and continued maintenance of any additional equipment arguably equally or more challenging for these facilities relative to a refinery or a chemical plant. BP believes that a first year BAMM approach is essential to a smooth implementation of this rule.

In addition, BP interprets the rule to mean that any measurement that is to be collected at a frequency of once every two years must be collected by the end of the first year of the rule (December 31, 2011) to allow for the preparation of the 2011 report. If this interpretation is consistent with EPA's intent, BP is fine with that the intent. If there is a requirement to have the monitoring completed sooner, then BP would like to add that to the list of BAMM extension request-eligible monitoring activities.

Response: EPA disagrees with the comment that the monitoring methods in today's final rule are too challenging, as today's final rule does not require the installation of any permanent monitors. In addition, some of the monitoring methods (e.g., use of emission factors) may not require the installation of any monitoring equipment, and emission assessments may be done at any time during the year, and measurements do not necessarily need to be undertaken during the first quarter. Please see response to comment EPA-HQ-OAR-2009-0923-1011-27. However, EPA considered that it may not be feasible for all reporting entities to fully comply with 2011 reporting requirements and therefore will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F. Regarding the comment on measurement frequency, please see the response to EPA-HQ-OAR-2009-0923-1151-64.

Comment Number: EPA-HQ-OAR-2009-0923-1015-17
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
It is not industry standard to determine GOR by individual wellhead. Yates requests the use of BAMM for the first reporting year.

Response: EPA will allow use of best available monitoring methods for some sources. Please see the preamble Section II.F. However, EPA disagrees that special provisions are necessary for wellhead GOR, as today's final rule allows for reporters to estimate GOR using your available data.

Comment Number: EPA-HQ-OAR-2009-0923-1015-22
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Meters are not designed to monitor intermittent flow. As liquids unloading has previously not generally metered, it will be difficult to estimate the orifice size and/or meter capacity in order to provide direct data to calculate this. As the process of installing meters for this purpose will be experimental, PAW proposes that BAMM is used for this estimation for the first reporting year. For smaller wells, calculation methodology 2 would be most appropriate, however the number of hours the well was vented is difficult to monitor. PAW requests the use of BAMM for the first reporting year as operators attempt to resolve this issue.

Response: EPA disagrees that use of best available monitoring methods will be necessary for all well venting for liquids unloading because of issues with meters, because today's final rule allows the alternative option of using reservoir and well parameters to perform an engineering calculation. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1030-1
Organization:
Commenter: Michael Leonard

Comment Excerpt Text:
The time between the publishing of the final rule in the Federal Register and the beginning of the reporting period will likely be inadequate to implement the data gathering requirements as stated in the final rule due to the enormous data gathering requirements. We propose that best available methods be permitted in the first quarter of the 2011 reporting year

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1082-9
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenters recommend that EPA allow the use of best available monitoring methods for a designated time period (e.g., three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used. (page 23)

Currently, methane leak detector cameras are not on all segments of natural gas pipelines. Thus, it is recommended that the EPA allow reporters to use best available monitoring methods. MidAmerican believes that 18 months is a reasonable amount of time to allow an individual company to acquire the necessary equipment and train staff on its operation. Flexibility is important in lowering the economic burden and allowing the use of best available monitoring methods for all parameters while developing the reporting capabilities.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F. The commenter has misinterpreted the rule, as it does not require leak detection on natural gas pipelines.

Comment Number: EPA-HQ-OAR-2009-0923-1015-20
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
This will require installation of flow meters for this requirement in many instances. PAW requests the use of BAMM for the first reporting year.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1015-21
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Yates will need to install flow meters for this requirement. Therefore PAW requests the use of BAMM for the first reporting year.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1015-3
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Furthermore, there are significant numbers of sources requiring direct measurement. As required in 98.234(b) **–** Monitoring and QA/QC requirements, "All flow meters, composition analyzers, and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year …" Calibrating all meters, composition analyzers and pressure gauges PRIOR to the reporting year will be nearly impossible given the number of components to be calibrated. At the least, operators should have the ability to use best available data for the first quarter of 2011. Furthermore, acid gas removal stacks will require the installation of not one, but TWO meters that must meet these requirements. Three months is simply not enough time to implement the requirements outlined in the rule as written.

PAW recommends that EPA provides BAMM opportunities for the first reporting year.

Response: EPA will allow the use of best available monitoring methods for certain sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1019-1
Organization: Red Cedar Gathering
Commenter: Ethan W. Hinkley

Comment Excerpt Text:
Best Available Monitoring Methods

EPA is seeking comment on the proposal not to allow the use of best available monitoring methods for part or all of the first year of data collection. Red Cedar believes that EPA should allow the use of best available monitoring methods for the first year of data collection due to the short timeframe for compliance that is being provided. Specifically, EPA should allow best available monitoring methods for parameters subject to direct measurement, such as compressor rod packing vents, to allow companies sufficient time to install the proper metering devices and/or hire a contractor to conduct the monitoring.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1167-27
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:

Allow “best available data” for at least year one, and preferably for the years one and two, for difficult to measure sources (i.e. the Year 3 sources from above) based on published emission factors and other emission estimation methods from the API Compendium and developed by Noble for its ongoing annual GHG inventory program. Noble prefers the previous options over this approach because this exercise would result in year one facility GHG emissions that differ from subsequent reporting years based solely on methods. This would lead to confusion when comparing subsequent reporting year data or among outside reviewers of the information.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F. EPA will not allow the use of any method under BAMM because the usefulness of the collected data would be questionable given that it would be obtained using inconsistent methods. Please see The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98) Section II.G.

Comment Number: EPA-HQ-OAR-2009-0923-1018-6
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:

Pre-amble, page 23, "EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenter's [*sic*] recommend that EPA allow the use of best available monitoring methods for a designated time period (e.g., three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used."

- Many of the proposed emission estimation methodologies are far beyond common practice for GHG emission inventory development from an oil and gas operations perspective. Therefore, CAPP recommends that EPA allow best available monitoring methods (BAMM) for the first year of the program to provide the time required to develop the data gathering and management, sampling and analysis and reporting systems necessary to meet the requirements of the reporting rule. ·

- CAPP believes that BAMM should be applied to all calculation methodologies including: direct measurement, engineering calculations, and emission factor calculations.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1173-1
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:

EP A should allow for the use of best available monitoring methods during the first reporting year for all parameters, including those subject to direct measurement, engineering calculations, and/or emission factors

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1173-8
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

<u>Comment Excerpt Text:</u>
Proposed Rule Effective Date / Best Available Monitoring Methods

"EPA seeks comment on the proposal not to allow use of best available monitoring methods for part or all of the first year of data collection. Further, if commenters recommend that EPA allow the use of best available monitoring methods for a designated time period (e.g., three months), EPA seeks comments on whether requests for use of best available monitoring methods should only be approved for parameters subject to direct measurement, or also in cases where engineering calculations and/or emission factors are used." (75 FR 18612)

Resolute Comments:

Resolute is concerned that the proposed effective date (January 1, 2011) of Proposed Subpart W does not provide sufficient lead-time for full implementation (e.g., interpret the rule, determine applicability, training personnel, setting up a compliance program, establishing recordkeeping systems and databases, etc.) from the time EPA finalizes the rule, which may not occur until sometime in late summer or fall of 2010. As a result, Resolute recommends delaying the effective date until January 1, 2012.

If EPA insists on a January 1, 2011 effective date, Proposed Subpart W should allow for the use of best available monitoring methods during the first reporting year to lessen the burden of reporting upon the industry while still collecting reasonably available data on GHG emissions. EPA should allow the use of best available monitoring methods for all reporting parameters, including those involving direct measurement, engineering calculations, and/or the use of emission factors.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F. EPA disagrees, and requires reporting of calendar year 2011, please see the proposed rule April 2010 preamble Section II.A.

Comment Number: EPA-HQ-OAR-2009-0923-1011-32
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>

Screening based on best available data:

In the alternative, until monitoring has been conducted at a facility, EPA should allow potentially affected Subpart W sources to employ best available data at a facility or onshore production “reporting area” level to estimate GHG emissions and determine applicability against the 25,000 metric tons threshold based on the estimated emissions. The best available data includes 2006 IPCC Guidelines, U.S. GHG Inventory, DOE 1605(b), The Climate Registry, California Climate Action Reserve and corporate industry protocols developed by the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association and measurement data developed internally by the reporters.

Companies should be allowed to use these best available methods to estimate total emissions from facilities or onshore production reporting areas for which monitoring at Subpart W facilities has not yet been conducted, either because the rule is new or because the facilities have not yet been estimated to exceed 25,000 metric tons based on best available methods. Companies should be permitted to employ the estimated results to decide whether those facilities that have emissions over 25,000 metric tons. Once a facility’s estimated emissions based on best available methods exceed 25,000 metric tons, the first year monitoring methods would be carried out per the final rule at these “screened” facilities and reports for the first year will be from these facilities that have been “screened” to emit over 25,000 metric tons CO_2e.

Response: EPA plans to develop a screening tool that may be used to assist companies in determining their applicability. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1014-8
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
Best Available Monitoring Methods

As currently proposed, Subpart W will require those facilities to which the rule may apply to have their data collection methods in place by January 1, 2011. Unlike those industry sectors currently subject to EPA's mandatory reporting rule under the original April 2009 proposal, facilities covered by Subpart W (and, indeed, those facilities attempting to determine whether Subpart W applies to them, as discussed above in Section C of these comments) are not permitted to collect "best available" data for a period of time to allow sources a reasonable amount of time to phase in the more burdensome monitoring requirements of the proposal. Because many, if not most, facilities do not have any protocol currently in place to gather this data, and because any relevant information that has been collected is likely not centralized, IOGA-WV urges EPA to authorize facilities potentially subject to Subpart W to use industry-established emission factors for the determination of applicability and for the first year's reporting to allow time to implement a the complete monitoring and measurement program required by Subpart W. This approach would allow EPA to begin its collection of data for 2011, to alleviate what is likely to be a very high demand for needed services to meet monitoring requirements, and to address concerns that there is currently a paucity of companies and technicians with expertise in Subpart W's proposed monitoring methods.

Response: EPA will allow the use of best available monitoring methods for some sources. Please see the preamble Section II.F. EPA plans to develop a screening tool that may be used to assist companies in determining their applicability. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1060-21
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type:
CBM produced water emissions

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(r)

Monitoring requirements/parameters:
1. For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHGi, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230 (b)(3) through (b)(8),GHGi equals one.
2. Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.
Comment:
This source [CBM produced water emissions] is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs. As measuring emissions from this activity is currently not industry standard, Yates requests the use of BAMM for the first reporting year.

Response: EPA has removed monitoring emissions from CBM produced water in today's final rule. Please see the preamble Section II.E and response to EPA-HQ-OAR-2009-0923-1151-129 in today's final rule.

VOLUME 13: SELECTION OF PROPOSED GHG EMISSIONS CALCULATION AND MONITORING METHODS

13.0 SELECTION OF PROPOSED GHG EMISSIONS CALCULATION AND MONITORING METHODS

Comment Number: EMAIL-0001-7 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
Direct Measurement

Although EPA has reduced some direct measurement requirements from the first Subpart W proposal, EPA still chooses to ignore longstanding and accepted international protocols for emissions calculations that other countries have adopted and currently use to calculate their oil and gas sector emissions. This includes Australia NGERS, EU-ETS, and Alberta for which all emissions are based on the API Compendium-IPIECA standards. EPA is assuming that better data will result from documenting and calculating emissions from every single small component related to oil and gas production instead of using carefully documented emissions factors applied across larger units. This procedure ignores the rules of probability and statistics and rejects average values in favor of counting every bean. There is no reason to believe that this burdensome method of data collection will produce an emissions number of greater value or validity than other accepted and proven techniques. The proposed rule is considerably more burdensome for onshore facilities than offshore facilities where MMS GOADS reporting standards are acceptable.

Response: EPA evaluated existing monitoring methods and determined the most appropriate methodologies to collect quality data for the purposes of this reporting rule while managing burden to the industry. In several cases in this rule, EPA used monitoring methods that are common practice in the industry and referenced in the API Compendium. For example, the use of simulation software programs for dehydrators and tanks, mass balance approach for AGR units, and engineering estimation of blowdown vent stack emissions.

In cases where EPA determined that existing emissions factors are not appropriate for the purposes of this reporting rule, EPA used the most recent measurement data available to develop new factors. For further details, please see rulemaking docket EPA-HQ-OAR-2009-0923 under "Revisions to Processing Leaker Emission Factors in Rule Table W-2." The API Compendium provides emissions factors that are based on the Gas Research Institute study[182] that are known to underestimate emissions from several key sources. For more information regarding these

[182] EPA/GRI (1996) Methane Emissions from the Natural Gas Industry. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.

sources please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). For these sources, EPA has either developed new emission factors, required engineering calculations, or required the direct measurement of emissions while considering the burden for each quantification methodology.

EPA agrees with the commenter on counting of components in onshore production. In today's final rule, EPA has replaced individual component counts and population based emissions factors for onshore petroleum and natural gas production with major equipment counts and population emission factors. To further reduce burden, EPA has also provided default average component counts for major equipment. For further clarification, please refer to Section II.D of the preamble to today's final rule.

With regards to offshore operations, please see the response to EPA-HQ-OAR-2009-0923-1155-14 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0837-1
Organization: Canadian Gas Association
Commenter: Michael Cleland

Comment Excerpt Text:
We suggest that the primary focus of the EPA's Subpart W rule should be to focus on improving the quality in the inventory estimates through a reporting rule that:

• encourages innovation in fugitive emissions monitoring and control measures,

• expands industry experience and knowledge on fugitive emissions inventory monitoring and reporting,

• drives continuous improvement in the quality of the data, and

• promotes cost-effective emissions reductions.

The proposed rule, as currently drafted, is very prescriptive in its use of specified emission factors and monitoring methods, requiring all Local Distribution Companies (LDCs) to report using the same factors and methods. We are concerned that this "consistency" will be misinterpreted as "accuracy" by the public, stakeholders and regulators, when in fact a reporting rule that permits alternative methods and use of more accurate data will provide better national estimates and drive more informed policy and regulation.

In our view, there are policy approaches that will result in better outcomes. For example, Canadian transmission and distribution companies are proposing to manage fugitive emissions under their corporate asset management systems, much as they undertake pipeline integrity management for safety purposes. This requires defined objectives and measured performance.

This asset management approach will be:

• adaptable and change over time as new technology or methods are adopted;

• results oriented as performance measurement is required and operators who best know the system determine how to meet objectives and are accountable for these; and

• core to each company's business, by aligning environmental risk management (i.e.• fugitive emissions) with safety, integrity. security and other risks.

Response: The data reporting requirements for subpart W were designed to collect GHG emissions data from petroleum and natural gas systems to inform future policy. Today’s final rule requires activity data be reported and measurement of emissions where there is very limited emissions data publicly available. In regard to LDCs, it allows for the use of emissions factors for smaller sources, and provides leaker factors in conjunction with leak detection where emissions sources are large in magnitude. EPA disagrees with the assertion that subpart W is too prescriptive. Today’s final rule has the intent of informing future policy only and not requiring any emissions reduction. EPA requires monitoring methods that are a balance between “consistency” and “accuracy” of emissions that will be reported. Accurate reporting of emissions from LDC would have required not only leak detection but also measurement of those emissions. However, to mitigate cost concerns, EPA has limited leak detection and does not require direct measurement. In addition, today’s final rule provides methods for tracking emissions reductions should the reporters choose to voluntarily perform them, such as doing multiple leak surveys and applying leaker emission factors for the period that leaks are determined to occur. Also, as with other rules in the past, EPA may revisit methodologies and allow for alternative work practices or newer data to improve results as such data comes available and at the Agency’s discretion. Hence, EPA does not agree that an inconsistent characterization of emissions from the industry can sufficiently inform future policy and requires uniform monitoring and reporting requirements in today’s final rule. In regards to the use of an asset management approach, EPA disagrees with the comment to allow reporters to choose monitoring methods under an asset management approach that are not specified in subpart W. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98) that provides further details on consistency requirements across the rule. Finally, today’s final rule does not address emissions reduction, only emissions reporting.

Comment Number: EPA-HQ-OAR-2009-0923-0837-10
Organization: Canadian Gas Association
Commenter: Michael Cleland

<u>Comment Excerpt Text:</u>
We suggest that EPA consider modifying the proposed rule to reduce compliance costs. In particular, we recommend that EPA remove the current requirement for mandatory site leak detection at this time and allow use of population emission factors. An alternate option would be to remove or decrease leak detection frequencies over time when the field data demonstrate that reduced leak survey frequencies are warranted. The reporting rule should also allow LDC's the

option to file based on alternative quantification methods or emission factor data where improved data accuracy can be achieved.

Response: EPA is retaining the annual equipment leak detection requirements for natural gas distribution, however EPA has provided more flexibility and reduced the compliance cost by allowing facilities to use alternative leak detection equipment. For further clarification, please refer to Sections II.E and II.F of the preamble to today's final rule.
With regard to the use of population factors, today's final rule allows for some above ground metering and regulator stations to be monitored using station-level emission factors.

Comment Number: EPA-HQ-OAR-2009-0923-0837-8
Organization: Canadian Gas Association
Commenter: Michael Cleland

Comment Excerpt Text:
Pipe Data by Material Type: Not all LDCs will have complete data on mains and services broken down by pipe material and the EPA rule should acknowledge this reality.

Response: EPA disagrees that not all LDCs will have complete data on main and services broken down by pipe material. EPA has determined that the pipe material data already reported to the Department of Transportation, per CFR title 49, part 191, Section 11, is sufficient for the purposes of this reporting rule.

Comment Number: EPA-HQ-OAR-2009-0923-0847-5
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Page 18637-18645. § 98.233. Calculating GHG emissions: It is unclear whether paragraphs (a) through (r) and (u) through (z) apply to both onshore and offshore facilities or only to onshore facilities. Since paragraph (s) specifically refers to offshore facilities, we assume that all other paragraphs in this section refer only to onshore facilities. Please consider clarifying this and, perhaps, reorganizing this part such that the offshore paragraph is at the beginning or end rather than in the middle of the numerous onshore paragraphs.

Response: Please refer to Section 98.232 of today's final rule for a complete list of the sources included under each industry segment; each industry segment need only report emissions sources listed under the particular industry segment in Section 98.232. Section 98.233(s) of today's final rule is a stand alone paragraph that outlines the GOADS reporting requirements for offshore petroleum and natural gas producers. EPA has reviewed the content and placement of Section 98.233(s) in today's final rule and has determined that the organization and placement of that section outlines the requirements for offshore operators.

Comment Number: EPA-HQ-OAR-2009-0923-0847-8
Organization: United States Department of the Interior

Commenter: Willie R. Taylor

Comment Excerpt Text:
MMS prepares emission inventories for OCS facilities in the Gulf of Mexico every three years. The last emissions inventory was prepared for the year 2008. The next inventory is planned for the year 2011. However, since MMS calculates emissions for all facilities, which number in the thousands, the complete inventory will not be available until sometime in 2013. We can assume therefore that the facilities would need to perform their own calculations in order to meet the March 31, 2012 reporting deadline. We can also assume that the facilities will be required to report emissions annually. However, this is not clearly stated in the rule. Clarification is needed for the final rule.

Response: EPA disagrees that reporters in the Gulf of Mexico OCS will need to calculate their own emission for calendar year 2011. Please see Section II.D of the preamble to today's final rule for how EPA intends to collect emissions data from offshore reporting in the first reporting year.

Comment Number: EPA-HQ-OAR-2009-0923-1011-35
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.232(b) GHGs to report for offshore petroleum and natural gas production

There is a significant disadvantage in the reporting requirements for onshore versus offshore operators, even though similar emission sources and practices are used. This difference is not explained in the TSD or the proposed rule preamble.

For offshore oil and gas production, the GOADS program relies on counts of emissions sources, volumes of throughputs from significant pieces of equipment, and parametric data to account for non-combustion emissions. This is in sharp contrast to the requirements proposed for onshore oil and gas production operations. In addition, since the Mineral Management Services only collects GOADS data once every three years, the EPA proposes that offshore operators scale emissions based on changes in production rates for the interim years.

Onshore operators should be allowed to use similar methodologies based on throughputs and counts of major equipment. In addition, onshore oil and gas production operations should be allowed to scale emission estimates for two out of three reporting years.

Response: In today's final rule, EPA has modified several reporting requirements to reduce the burden for reporting onshore operators. Please see Section II.E of the preamble to today's final rule for a detailed description of the changes made since the April 2010 proposal.

The commenter does not indicate which sources require more rigorous monitoring in the rule in comparison to GOADS and hence EPA has not provided a prescriptive comparison of each source. For further details, please see response to EPA-HQ-OAR-2009-0923-1155-14. Finally, EPA disagrees with the two to three year reporting cycle for onshore production. Onshore production emissions are significantly higher than offshore emissions and hence EPA has retained the yearly monitoring of onshore production emissions sources.

Comment Number: EPA-HQ-OAR-2009-0923-1011-6
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.232(b) GHGs to report for Offshore Petroleum and Natural Gas Production.—Onshore petroleum and natural gas production operators should be allowed to use the same approach as the offshore petroleum and natural gas production operators due to similar emission sources, functional use and production practices.

Response: EPA disagrees with this comment. However, after considering several comments, in today's final rule, EPA is now including alternative methodologies in some cases to reduce the burden for onshore operators' reporting. Please see Section II.E of the preamble to today's final rule for a detailed description of the changes made since the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002).

Comment Number: EPA-HQ-OAR-2009-0923-1024-24
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Comments on the Proposed Quantification Methodologies. As stated above, Kinder Morgan generally supports EPA's overall approach of requiring engineering estimates or emission factors to be used to quantify emissions from the onshore petroleum and natural gas sector where possible, and minimizing the use of direct measurement methods. Engineering estimates and emission factors have a long track record in our industry, are well-understood and easy to apply consistently, and are much more cost-effective than direct measurement. However, Kinder Morgan makes the following suggestions and technical comments to EPA's proposed quantification methodology for several source types.

1. Best Available Monitoring Methods. Kinder Morgan requests that EPA reconsider its decision not to propose allowing BAMM to be used for all or part of the first year of compliance with the proposed Subpart W.[183] As proposed, Subpart W would require Kinder Morgan to install a considerable number of meters at acid gas removal units, centrifugal compressor wet seal degassing vents, vents at reciprocating compressor rod packing cases, transmission storage tanks, and potentially other locations. Installing these meters is costly and time-consuming process in itself, and could result in substantial disruption to our operations since equipment must frequently be taken off-line in order to install a meter. Component surveys will also have to be conducted at facilities that require application of population emission factors, and do not have

[183] Proposed Subpart W, 75 Fed. Reg. at 18,612.

existing component counts. As explained below, Kinder Morgan also expects that the demand for optical imaging instruments and the services of companies that conduct leak surveys and measurements will exceed supply during at least the first year of compliance with Subpart W. Even if service companies can meet the demand, Kinder Morgan is concerned that services will be of low quality.

Kinder Morgan believes EPA has underestimated the amount of time that will be required to carry out these tasks, and has proposed an optimistic implementation schedule for the proposed Subpart W that leaves no room for error and creates substantial compliance risk. Our field testing of the proposed Subpart W methodologies at one of our natural gas transmission compression facilities indicates that leak detection and measurement at a single facility takes an experienced two-person team at least one full day to conduct. Additional preparation and follow up work is also required, causing the length of the inspection at a single facility to extend beyond two days. Importantly, our field tests did not involve testing reciprocating compressor rod packing venting in all three operating modes, as the proposed Subpart W would require. Three-mode testing of these units would require reciprocating compressors to be forcibly cycled through operating, operating depressurized, and standby modes, which would have significantly lengthened the time required to carry out the emissions survey. To conduct leak detection as proposed, Kinder Morgan and any company subject to Subpart W needs personnel, training, optical imaging equipment, temporary and permanent flow meters, and measurement equipment such as but not limited to calibrated bags and high volume samplers. In addition to purchasing equipment personnel will need to be trained on how to use the equipment, the equipment will need to be installed where applicable, and calibrated prior to January 1, 2011.

If the rule is finalized in September 2010, Kinder Morgan does not believe there will be sufficient time left in the year to complete this work to assure compliance with Subpart W beginning January 1, 2011. Kinder Morgan fully expects our field testing experience to apply to the other industry segments included in Subpart W. Thus, Kinder Morgan urges EPA to consider allowing BAAM to be used for the first year of reporting under the proposed rule. This approach would allow EPA to collect data on oil and gas sector emissions during 2011, while allowing our industry sufficient time to prepare for full implementation beginning 2012.

Response: In today’s final rule, EPA is allowing Best Available Monitoring Methods for certain sources and time periods. For more detailed information, please refer to Section II.F of the preamble to today’s final rule. EPA has also clarified several misinterpretations of the rule that would have required substantially more effort from reporters than was intended by EPA. Please see Section II.E and II.F of the preamble to today’s final rule for examples of these misinterpretations and how EPA has clarified them. Also, please see Section II.E of the preamble to today’s final rule for how EPA has simplified many of the monitoring requirements to reduce the effort to monitor and report emissions. With these clarifications and simplifications in monitoring methods and allowing BAMM for certain sources and time periods as noted above, EPA concluded that reporters will have sufficient time to comply with the rule.

Comment Number: EPA-HQ-OAR-2009-0923-1024-31
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Emissions Passing Through Manifold Vents. It is common for multiple emitting components in petroleum and natural gas systems to be attached to a single manifold vent. In such cases, it is most practical and accurate to monitor emissions at the manifold vent, rather than at each individual component attached to the manifold. However, the proposed Subpart W does not specify a monitoring method for manifold vents, and instead appears to require monitoring of individual components regardless of the vent configuration. Kinder Morgan recommends that EPA amend the proposed rule to allow for emissions monitoring at manifold vents where appropriate.

9. Gas Driven Pneumatic Pump Venting. For purposes of calculating vented emissions from gas-driven pneumatic pumps, Kinder Morgan believes that engineering calculations are the most efficient way to obtain the volume of liquid pumped annually by individual devices. However, the proposed methodology states that a “log of the liquid pumped annually” must be maintained.[184] Kinder Morgan requests that EPA clarify this methodology to state that engineering calculations are an acceptable way to measure the volume of liquid pumped by individual gas driven pneumatic pump.

Response: EPA is requiring emissions information to be reported by source type so that it can better inform policy. When different emissions sources are connected to a common manifold the reporter will provide a single estimate of emissions, which is not sufficient information for EPA to determine where the emissions are occurring. Hence, in today’s final rule, EPA has retained the requirement for reporting of emissions from individual equipment.
For the comment on natural gas pneumatic pump venting, EPA now requires the use of emissions factors for all pneumatic devices and pneumatic pumps in today’s final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today’s final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1024-45
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:

SECTION 98.233 Calculating GHG emissions.

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

(1) Calculate emissions using manufacturer data.

(i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer

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[184] Proposed 40 C.F.R. SECTION 98.233(c).

“gas consumption”) per unit volume of liquid circulation rate at pump speeds and operating pressures.

(ii) ~~Maintain a log of~~ ***Measure or estimate*** the amount of liquid pumped annually from individual pumps.

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

$Es,n = Fs * V$ (Eq. W-3)
Where:

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

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

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

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

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

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

Ea, co2 = (V1 * %Vol1) – (V2 * %Vol2) ***– (V3 * %Vol3)*** (Eq W-4)

Where:

$E_{a, co2}$ = Annual volumetric CO2 emissions at ambient condition, in cubic feet per year.

V1 = ~~Metered~~ total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient conditions, ***as measured by meter or estimated using engineering methods.***

%Vol1 = Volume weighted CO2 content of natural gas into the AGR unit.

V2 = ~~Metered~~ total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient conditions, ***as measured by meter or estimated using engineering methods.***

%Vol2 = Volume weighted CO2 content of natural gas out of the AGR unit.

V3 = Total annual volume of CO2 flashed off from the AGR unit and recompressed into a CO2 injection system to be injected into the ground, as measured by meter or estimated using

engineering methods.

%Vol3 = Volume weighted CO2 content of gas stream flashed off and captured for re-injection.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, quarterly gas samples must be taken to determine %Vol1 and %Vol2 according to methods set forth in SECTION 98.234(b).

(2) Calculate CO2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(3) Mass CO2 emissions shall be calculated from volumetric CO2 emissions using calculations in paragraphs (u) and (v) of this section.

(4) As an alternative to the method in Eq. W-4, CO2 emissions from AGR units may be calculated using an industry standard software such as ProMax®.

(f) Well venting for liquids unloadings.

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

(i) Calculation Methodology 1. For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, ~~a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in SECTION 98.234(b).~~ Calculate emissions from well venting for liquids unloading using Equation W-6 of this section.

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

Where:

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

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

FR = Flow Rate in cubic feet per hour, under ambient conditions as required in paragraph (f)(1)(i)(A), (f)(1)(i)(B) and (f)(1)(i)(C) of this section.

Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

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

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

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

(ii) <u>Calculation Methodology 2</u>. Calculate emissions from each well venting for liquids unloading using Equation W-7 of this section.

$E_{s,n} = [(0.37 \text{ X } 10^{-3}) * CD^2 * WD * SP * V] + [SFR * HR]$ (Eq. W-7)

Where:

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

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

CD = Casing diameter (inches).

WD = Well depth (feet).

SP = Shut-in pressure (psig).

V = Number of vents per year.

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

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

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

(B) [Reserved]

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(h) <u>Gas well venting during conventional well completions and workovers</u>. Calculate emissions from each gas well venting during conventional well completions and workovers using Equation W-9 of this section:

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

Where:

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

- (i) Separator oil composition.
- (ii) Separator temperature.
- (iii) Separator pressure.
- (iv) Sales oil API gravity.
- (v) Sales oil production rate.
- (vi) Sales oil Reid vapor pressure.
- (vii) Ambient air temperature.
- (viii) Ambient air pressure.

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

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

(2) If the tank vapors are continuous ***and sufficient to indicate dump valve malfunction*** then use a meter, ***calibrated bag, or high volume sampler*** to measure tank vapors ***as described in this paragraph (2)(i) or utilize the E&P Tanks software program.***

(i) Use a meter, such as, but not limited to a turbine meter, ***calibrated bag, or a high volume sampler*** to estimate tank vapor volumes according to methods set forth in SECTION 98.234(b), ***(c) or (d)***.

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

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

(i) Use the storage tank emissions volume and gas composition as determined in paragraph (j)(1) of this section.

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

(l) <u>Well testing venting and flaring</u>. Calculate well testing venting and flaring emissions as follows:

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

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

(ii) [Reserved]

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(4) Calculate GHG volumetric emissions at actual conditions using Equations W-13, W- 14, and W-15 of this section.

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

$E_{a,\,CO2}$ (combusted) = $\Sigma_{(j)}\, n_j * V_a * Y_j * R_j$ (Eq. W-14)

$E_{a,\,i}$ (total) = $E_{a,\,i}$ (combusted) + $E_{a,\,j}$ (um-combusted) (Eq. W-15)

Where:

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

$E_{a,\,CO2}$ (combusted) = Contribution of annual emissions from combustion from flare stack in cubic feet, under ambient conditions

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

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

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

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

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

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

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(p) Reciprocating compressor rod packing venting. Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows

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

Ea,i = *MT* * *T* * *M*i (Eq. W-17)

Where:

Ea,i = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions.

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

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

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

(2) If the rod packing case is connected to an open ended vent line then use one of the following two methods to calculate emissions.

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in SECTION 98.234 (c).

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

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

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

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

(4) ***For each compressor record the operational mode that occurs during the measurement.*** ~~Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period: (i) Operating. (ii) Standby pressurized. (iii) Not operating, depressurized.]~~

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

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

(q) <u>Leak detection and leaker emission factors</u>. You must use the ***appropriate standard*** methods described in SECTION 98.234(a) to conduct an annual leak detection of fugitive emissions from all sources listed in SECTION 98.232(d)(9), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. If fugitive emissions are detected for sources listed in this paragraph, calculate emissions using Equation W-18 of this section for each source with fugitive emissions.

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

Where:

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

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

EF = Leaker emission factor for specific sources listed in Table W-2 through Table W-7 of this subpart.

GHG_i = For onshore natural gas processing ***plants*** ~~facilities~~, concentration of GHG i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in SECTION 98.230(a)(3) through (a)(8), GHGi equals 1.

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

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

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

(3) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W-3 of this subpart for fugitive emissions detected from connectors; block valves; control valves; compressor blowdown valves; pressure relief

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(r) <u>Population count and emission factors</u>. This paragraph applies to emissions sources listed in SECTION 98.232(c)(2), ~~(c)(9)~~, (c)(15), (c)(21), ~~(d)(8)~~, (e)(6), (f)(4), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3) and (i)(4), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus $_{CO2}$ by weight do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W-19 of this section.

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

Where:

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

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

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

GHG_i = for onshore petroleum and natural gas production facilities and onshore natural gas processing ***plants*** ~~facilities~~, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in SECTION 98.230 (b)(3) through (b)(8),GHGi equals 1.

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

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

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

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions.

T_s = Temperature at standard conditions. (^oF).

T_a = Temperature at actual emission conditions. (^oF).

P_s = Absolute pressure at standard conditions (inches of Hg). Pa = Absolute pressure at ambient conditions (inches of Hg).

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

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

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

Where:

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

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.

M_i = Mole percent of GHG i in the natural gas.

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

(i) GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in SECTION 98.234(b).

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

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

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

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

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

(vii) GHG mole percent in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W-23 of this section.

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

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO2e.

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

i = Density of GHG i, 0.053 kg/ft^3 for CO_2 and 0.0193 kg/ft^3 for CH_4.

GWP = Global warming potential, 1 for CO_2 and 21 for CH_4.

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

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

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

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

$Mas\ c,i = N * Vv * Rc * GHGi * 10^{-3}$ (Eq. W-24)

Where:

Mas c,i = Annual EOR injection gas venting emissions in metric tons at critical conditions “c” from blowdowns.

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

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

Rc = Density of critical phase EOR injection gas in kg/ft3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.

GHGi = Mass fraction of GHGi in critical phase injection gas.

~~(x) Hydrocarbon liquids dissolved CO2. Calculate dissolved CO2 in hydrocarbon liquids as follows:~~

~~(1) Determine the amount of CO2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Quarterly samples must be taken according to methods set forth in SECTION 98.234(b) to determine retention of CO2 in hydrocarbon liquids immediately downstream of the storage tank. Use the average of the quarterly analysis for the reporting period.~~

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

$\cancel{Mass_{s,CO2} = S_{hl} * V_{hl}}$ ~~(Eq. W-25)~~

~~Where:~~

~~$Mass_{s, CO2}$ = Annual CO2 emissions from CO2 retained in hydrocarbon liquids beyond tankage, in metric tons.~~

~~S_{hl} = Amount of CO2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.~~

~~V_{hl} = Total volume of hydrocarbon liquids produced in barrels in the reporting year.~~

~~(y) Produced water dissolved CO2. Calculate dissolved CO2 in produced water as follows:~~
~~(1) Determine the amount of CO2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in SECTION 98.234(b) to determine retention of CO2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. Use the average of the quarterly analysis for the reporting period.~~

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

~~Mass, CO2 = Spw * Vpw (Eq. W-26)~~

~~Where:~~

~~Masss, CO2 = Annual CO2 emissions from CO2 retained in produced water beyond tankage, in metric tons.~~

~~Spw = Amount of CO2 retained in produced water in metric tons per barrel, under standard conditions.~~

~~Vpw = Total volume of produced water produced in barrels in the reporting year.~~

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

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

(aa) <u>Unsafe-to-monitor and difficult-to-monitor components</u>. Calculate emissions from unsafe-to-monitor and difficult-to-monitor components using an appropriate emission factor or emission rate.

Response: EPA has reviewed the commenter’s proposed edits. In today’s final rule EPA now requires the use of emissions factors for all pneumatic devices and pneumatic pumps. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble for further details.

After considering several comments, EPA has determined that there is sufficient flexibility in terms of acceptable methods for calculating GHG emissions from AGR units and has revised the monitoring method for AGR units in today's final to provide multiple options and eliminate the need for new meters to measure throughput. Please see the response to EPA-HQ-OAR-2009-0923-1024-26 for further details.
In regards to changes in well venting for liquids unloading calculations, please see the response to EPA-HQ-OAR-2009-0923-1018-28 for further details.
EPA agrees with the comment regarding the typographical error in the gas well venting and blowdown vent stacks paragraph and the necessary changes have been made in the today's final rule.

With regards to the title of the emissions source for storage tanks in onshore production, in today's final rule EPA requires the monitoring of only hydrocarbon liquids for onshore production storage tanks. The source is not required to be monitored for processing facilities in today's final rule. This will avoid any confusion with monitoring of non-hydrocarbon tanks in onshore production.

EPA does not agree with the commenter on the title for transmission storage tanks. The intent of this source is to monitor any flow through emissions in these transmission tanks from leaking dump valves and not the flashing from the liquids. Therefore, any liquid tank that stores either water or hydrocarbon can have flow through emissions from dump valves. Hence, EPA has retained the title of the source type.

EPA does not agree with the commenter on suggested alternatives to meters to quantify emissions from transmission storage tanks. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1024-30.
In today's final rule, EPA has modified the equations related to flare stacks emission calculation to capture un-combusted CH_4 emissions, un-combusted CO_2 emissions and combusted CO_2 emissions.

In today's final rule, EPA has agreed to allow compressor venting measurement in the 'as found' mode. For further clarification, please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

EPA does not concur with the change in the facility definition title for processing facilities. EPA has developed the definition for processing facilities to capture all relevant sources of emissions from gas processing facilities, including residue gas compression equipment dedicated to the processing facility. However, EPA has revised in today's final rule the processing facility definition. For further clarification, please see Section II.F of the preamble to today's final rule.
EPA disagrees with the exclusion of EOR hydrocarbon liquids dissolved CO_2 from the reporting rule. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1011-21.
EPA agrees with the exclusions of produced water dissolved CO_2. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

EPA has provided an equipment threshold for onshore production and natural gas distribution external combustion portable and stationary equipment. Please see Section II.E of the preamble to today's final rule for further details.

EPA disagrees with the commenter on the use of emissions factors or emissions rates for unsafe-to-monitor or difficult-to-monitor as EPA has provided alternative methods such that safety concerns are eliminated. EPA has included sufficient provisions in today's final rule to account for unsafe-to-monitor or difficult to-monitor equipment. Please see the response to EPA-HQ-OAR-2009-0923-1024-11 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1031-8
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
Additionally, the API Compendium in particular has been accepted as an international standard for estimating GHG emissions across the oil and gas industry. For example, Australia NGERS, EU-ETS, and Alberta emission inventories are all based on the API Compendium. EPA is assuming that a significant increase in overall accuracy will result by requiring more complex and costly estimation of GHG emissions from even the smallest sources within the natural gas gathering and processing industry. This assumption is made while overlooking the EPA's own data that indicates the natural gas gathering and processing industry emits only a very small fraction of the total US GHG emissions annually. In addition, the currently proposed Subpart W ignores the standards of statistical averaging.

While Anadarko supports the full use of the API Compendium to calculate GHG emissions for all sources covered by the proposed Subpart W, at a minimum we suggest the application of the API Compendium in place of any direct measurement methods. For the gas gathering and processing sector, direct measurement is generally proposed to be limited to compressor wet seal vents and rod packing venting. The current proposal potentially requires direct measurement of compressor rod packing vents from every cylinder of a compressor in cases where the vent lines are not tied to a common line, which is a common practice in gathering compression facilities and production facilities. The prescribed methods for these sources is flawed by assuming a snapshot measurement applied across an entire year is more accurate than an emission factor based on well documented and controlled studies.

Response: Today's final rule does not require the reporting of emissions from gas gathering and boosting segment of the industry, please see Section II.F of the preamble to today's final rule. However, EPA disagrees with the commenter on the use of API compendium. For further details, please see the response to EPA-HQ-OAR-2009-0923-3524-4.

Comment Number: EPA-HQ-OAR-2009-0923-1070-1
Organization:
Commenter: Michael Leonard

Comment Excerpt Text:

(98.233) Numerous source types and respective calculation methods are given to determine the amount of CO2 being released to the atmosphere at a wellsite. It can be assumed that the majority of CO2 being produced at a wellsite will either flash/vent/leak to the atmosphere at STP conditions and the remaining dissolved CO2 in produced water and hydrocarbon liquids will be negligible, due to STP conditions. The minimal quantity of dissolved CO2 does not warrant the quarterly sampling burden. We propose that a single annual sample be taken that is representative of the CO2 concentration at the wellhead. This concentration and the annual flow of the well can be used to determine the mass of CO2 being produced at the well. This mass of CO2 will flash to the atmosphere at STP conditions on sites where the products are not piped off-site under pressure. On sites that pipe products off-site under pressure, a second sample may be needed to determine the concentration of the CO2 in the methane stream that would be representative of the CO2 being transported offsite. A mass balance equation could then be used to determine CO2 being flashed/vented/leaked to the atmosphere at the site. The second sample, representative of what is transported off-site under pressure, would only be necessary if a downstream processing facility was capturing a CO2 stream for the purpose of supplying CO2 to a commercial/industrial customer. Otherwise, the CO2 being transported off-site under pressure can also be assumed to go to atmosphere at a downstream location and therefore, a mass of CO2 being produced at the wellsite would best represent the quantity of CO2 ending up in the atmosphere.

Response: EPA did not intend for the sampling of hydrocarbon liquids and produced water other than at EOR sites that use CO_2 injection. With regard to the annual sampling of hydrocarbon liquids, please see the response to EPA-HQ-OAR-2009-0923-0582-40.

Today's final rule does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1072-1
Organization:
Commenter: Michael Leonard

Comment Excerpt Text:

(98.230) It has been stated in the preamble to this subpart that mass balance equations are not acceptable to calculate overall emissions due to the inaccuracy of the flow meters necessary to determine flow rates. However, the concept of tolerance stacking may come into play when considering multiple source categories and associated calculations. Tolerance stacking is well known in several industries. In this scenario, multiple smaller systems each have an associated acceptable calculation error. Though these calculation errors may be small when viewed individually, they have the ability to upon themselves as additional systems with their own calculation errors are added. A scenario can occur where the errors favor a high or low tolerance, and therefore have the ability to add up. This may produce a significantly higher error than a simple mass balance equation. We propose that a study be conducted to address the concept of error tolerance stacking and how it relates to the numerous source categories being aggregated under the proposed Subpart W such that the most accurate overall calculation method is used.

Response: EPA disagrees with the commenter. EPA made the cited statement specifically in relation to transportation pipelines. It is not clear from the comment how tolerance stacking can be practically used to separate the error component from actual meter reading of gas throughput in gas transmission systems. Hence, EPA does not have sufficient information from the commenter to provide any further response.

Comment Number: EPA-HQ-OAR-2009-0923-1080-37
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>
Aka recommends that EPA remove the requirement in Section § 98.236(b) for operators to report emissions separately for “standby” equipment. First, the term “standby” is not defined anywhere in the rule (neither Subpart W nor Subpart A). Moreover, equipment is generally not specifically designated by operators as “primary” or “standby.” This adds an additional layer of reporting that is unwarranted and confusing, uses nebulous terminology, and provides no meaningful information. `

Response: After reviewing applicable comments from the industry, EPA has eliminated the requirement to report emissions separately from standby equipment, except compressors, in today’s final rule. The emissions from isolation valves when a compressor is in standby depressurized mode can be significant, which is why EPA requires these sources to be monitored. Hence, EPA has removed the provision for reporting standby equipment in Section 98.236(b) and has simplified the requirements for monitoring of compressors in standby mode. Please see the response to EPA-HQ-OAR-2009-0923-0055-16 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1170-4
Organization: Pioneer

<u>Comment Excerpt Text:</u>
The rule should not require actual fugitive component count

With the addition of the onshore petroleum and natural gas production segment of the Subpart, the scope of this Subpart has been vastly expanded, especially the inclusion of population count of fugitive components. It would be extremely time consuming and cost intensive for individuals to go out to approximately 1,800 tank batteries and over 6,000 wellheads in the Permian Basin alone to count these components and document these data based on this Subpart's definition of "facility". This would be a monumental task to conduct and maintain in every basin where Pioneer operates in the U.S. Further, no laboratory has the infrastructure to handle the anticipated volume of samples from Pioneer, as well as other operators combined. Moreover, an actual count is not needed to develop a reasonable estimate of fugitive emissions. A population average from similar batteries should provide reasonable results. Perhaps a representative battery could be chosen in each "reporting unit" (per the reporting unit" recommendation in point 1).

Alternatively, batteries could be grouped in each basin by their characteristics or size, based on throughput, and a population average of components could be estimated for each size grouping.

Response: In today's final rule, EPA requires the monitoring of major equipment and not individual components. For further details, please see Section II.D of the preamble to today's final rule.

EPA disagrees with the commenter on the grouping of fields within a basin. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-46.

Comment Number: EPA-HQ-OAR-2009-0923-1305-33
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.236: Data Reporting Requirements

The following paragraphs in this section of the proposed rule request data reporting by basin and field. If reporting is done at a basin level for comparison to the applicability threshold, the data reporting requirements should be consistent with the basin-wide rollup of emissions and the data should not have to be reported at a field level due to the additional burden that would be imposed in order to delineate the data by field and the redundancy in reporting the field level data. BP requests that the term "field" be deleted from the following paragraphs in this section: Section 98.236 (c)(6), (7), (8), (12), (13), (15), (16), (21), and (22)

Response: EPA disagrees with the commenter. Please see response to EPA-HQ-OAR-2009-0923-1151-63 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-37
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Alternative Option for Reporting Onshore Petroleum and Natural Gas Production

EPA evaluated and is taking comment on one alternative option for reporting from onshore petroleum and natural gas production; field level.

BP does not believe the regulatory named field level (as defined in the referenced EIA field list) is a useful concept for either threshold or emission estimation purposes. With over 44,000 named fields in the EIA list, the widely varying number of wells in each named field (from zero to tens of thousands), and the dynamic nature of the list, it would introduce a significant amount of uncertainty and additional burden. Of particular concern is the changeable nature of the list. As State Oil and Gas agencies modify their field lists, the EIA subsequently modifies their list, usually with a delay of about one year. For example, Wyoming is actively reviewing their named fields with a goal of combining like fields (similar to the sub-basin proposal) and reducing the number of fields listed. This flux in field names and boundaries would pose a significant challenge to an owner/operator in determining what wells and facilities to group for threshold and other purposes under the rule.

C. Basin Versus Field Level Reporting

EPA seeks comments on our decision to propose the basin level approach, and whether there would be advantages to requiring reporting at the field level instead.

As described above, BP proposes an alternative method of grouping fields within a basin, based on common production characteristics. These groupings would be established and documented by the reporting operator in the monitoring plan. Emissions from the groupings would be summed at the basin level for comparison against the 25,000 tonne CO_2e reporting threshold.

Response: EPA disagrees with the commenter on the EIA field code master. EPA has analyzed the field code master for the last 4 years and found that the changes in the database are insignificant. In fact, 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). Hence, EPA does not consider these changes to be of any significantly dynamic nature. Therefore, although EPA has not required the use of field code master as a facility definition, EPA has required the use of the definition in monitoring methods such as for gas well venting during completions and workovers with hydraulic fracturing. Also, EPA does not agree with the concept of grouping fields within a basin; please see response to EPA-HQ-OAR-2009-0923-1305-46 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-39
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Alternative Software Packages for Calculations

EPA seeks comment on whether there are additional or alternative software packages to E&P Tank and GlyCalc that should be required to be used to calculate emissions.

The rule should allow reporters to use E&P Tanks and GlyCalc or any commercial process simulator software (such as HySys or ProSim) to estimate emissions from tanks and glycol dehydration. The rule should also not specify the version numbers of the software packages, as these programs are updated periodically.
Response: EPA agrees with the commenter. With regard to software flexibility, please see the response to EPA-HQ-OAR-2009-0923-1014-12.

Comment Number: EPA-HQ-OAR-2009-0923-1305-44
Organization: BP America, Inc.

Commenter: Karen St. John

Comment Excerpt Text:
Specific Source Type Comments and Alternative Emission Estimation Methodologies

Following, BP proposes alternative estimation methodologies for many of the source types applicable to the Onshore Petroleum and Gas Production Sector (OGPG) and other source categories as applicable. These alternative methodologies are warranted to reduce the man power and cost burden and to address errors in EPA's assessment of specific sources and methodologies. Also, BP recommends that some of the source types be deleted from the final rule because of the insignificant GHG emissions associated with them (reasons/examples are provided below for relevant source type discussions). BP requests that the following 3 categories be deleted: (1) Hydrocarbon Liquids Dissolved CO2, (2) Produced Water Dissolved CO2, (3) ?

Response: EPA does not agree with the exclusion of hydrocarbon liquids dissolved CO_2 from reporting. However, EPA has clarified that the source is limited to CO_2 EOR operations only. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1011-21.

EPA agrees with the exclusion of produced water dissolved CO_2 from the reporting rule. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1305-57
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(q) and (r) Fugitive Emissions

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

BP supports EPA's decision to base fugitive emission estimates for onshore production on population count and emission factors. However, the methodology for arriving at a component count must be significantly changed to enable a reasonable approach to arrive at a component count for the hundreds of thousands of sites subject to the proposed rule. As currently structured, the rule would require a physical component count (along with concurrently gathering other information) at each individual well-site and associated facility. It is very likely that this amount of work could not be done by the end of 2011 and the projected costs are very high. To address this problem, BP suggests the following:

In a particular producing area (reporting unit or reporting area) operators tend to use similar equipment packages, such as separators, compressors, dehydrators, and tanks, and similar site layouts or configurations. BP suggests that EPA modify the methodology for arriving at a component count for a particular reporting unit as follows:

1. Require a component count for a small number (10 - 20) of each type of major equipment package. Inventory the number of each type of major equipment packages deployed in the reporting unit/area. Multiply the component counts by the number of major equipment packages to arrive at a total component count for the major equipment packages.

2. Require a component count for a small number (10 - 20) of each type of site (e.g. single well-site, multi-well site, tank battery, central production site, etc) for components which are not part of the major equipment packages. Multiply the site component counts by the number of sites of each particular type to arrive at a total component count for components not part of the major equipment packages.

3. Sum the major equipment and site component counts for each reporting area to arrive at the total component count for the reporting area and then apply the methodology specified in the rule (Section 98.233 (r)) to arrive at a fugitive emission estimate for the reporting unit/area.

4. Sum the fugitive emission estimates for all reporting units/areas within an identified basin for purposes of annual reporting.

By making these modifications to estimate component counts, EPA can achieve a more appropriate balance between the burden of the rule and the amount of emissions covered while still yielding good quality emission estimates. Adopting this methodology would also partially address the issue of the industry's ability to physically meet the rule requirements in the time contemplated by EPA.

A minimum component size for counting of components or leak surveys in the processing sector should be defined (i.e., line size). BP suggests that components associated with line or tubing less than or equal to 3/4-inch outside diameter should be excluded from both counts and leak surveys. This is consistent with other regulations for leak detection and repair programs. Rather than attempting to classify fugitive components by the type of fluid contained as depicted in Tables W-1 and W-2, EPA should allow operators to simply assume that all components are in gas service. If EPA does not enable this approach, then the rule should clarify the handling of multiphase flow which is common in the oil and gas production sector.

Response: In today's final rule, EPA requires the monitoring of major equipment and not individual components for onshore petroleum and natural gas production. For further details, please see Section II.D of the preamble to today's final rule. Hence, the commenter's suggested methodology is no longer relevant.

In today's final rule, EPA does not require the monitoring of tubing systems equal to or less than one half inch diameter. Also, EPA requires the counting of major equipment to estimate emissions, as opposed to counting components; please see Section II.F of the preamble to today's final rule for further details. EPA has clarified what major equipment belongs to oil or gas service in Section 98.233(r) of today's final rule and hence the issue on multiphase flow is no more relevant.

Comment Number: EPA-HQ-OAR-2009-0923-3522-3
Organization: Heath Consultants
Commenter: Milton W. Heath

Comment Excerpt Text:

Standardized Components (Flanges, Unions, Thread/Pipefittings, tubing connectors, valve stems, ball-valves, grease fittings, valve caps, unloader flanges, actuators etc.)
The largest number of components at any gas facility will be in the area of what we categorize as "standardized components". At most facilities, you should expect to see a minimum of 2000 components and as many as 10,000. Screening these components has typically been done in the past with the use of liquid bubble solution, ultrasonic leak detectors, leak screening with a pump driven gas detector or flame ionization detector (OVA/TVA)
The procedure for an electronic gas leak detector that may use infrared, catalytic oxidation, thermal conductivity or flame ionization, is to inspect the parameter of a connecting component with a specialized survey probe whereby a sample is pulled into the device and analyzed for the presence of hydrocarbons at a very low rate (PPM or % GAS). This process is labor intensive and time consuming because the operator must inspect every component that has natural gas pressure behind it which could possibly leak due to wear and tear, exposure to heat or vibration etc.

Newer Remote Infrared Laser Leak Detectors/Screeners
Recently, in the last four years, the introduction of remote infrared lasers has allowed operators to improve this screening process for "standardized components". Now it is possible to screen each connector at a distance of six feet to 100 feet away from the target source with the same accuracy and the sensitivity of flame ionization (down to 10 Parts Per Million). One of the great advantages of infrared laser leak detection is that the resulting indication of a leak at a given component is repeatable and consistent with each operator, regardless of what their level of experience or expertise is. So long as the laser spotter is used to show where the infrared laser is screening on the component and leaking gas is present, an audible alarm will be instantaneously heard while the concentration of that leak is displayed in parts per million metered on the display. These two bits of information are not adjusted or manipulated as with an imaging camera to insure a quality image, they are derived automatically and instantly because of the superior quality of the infrared laser coupled with sophisticated micro-processor controls which take the interpretation and mental fatigue away from the operator and put it into the screening device where it belongs.
The procedure used for leak screening with a remote infrared laser detector is to:
1. Turn the power button on and allow one minute for the device to warm up
2. Calibrate the laser in the carrying case with a known quantity of gas safely contained in a transparent hermetically sealed calibration cell (approximately 1% gas, non-explosive). This takes about 1 minute.
3. Place the control unit over your shoulder using the shoulder carrying strap and hold the grip of the transiever with your preferred hand and begin leak screening your target source.

4. Working from one end of the piping down to the other, slowly screen the openwings of flanges, valve stems, connectors by sweeping the laser spotter (built into the grip and depressed with your index finger for controlled spotting when you need it) across the target source in a zigzag motion from top to bottom. You can rapidly scan these areas to identify gas leaks which can then be confirmed with a liquid bubble solution and tagged for future quantification or direct measurement (based on your protocol).

IV. Leak Screening of Standardized Components with the Gas Imaging Camera versus infrared laser technology.

The current proposed EPA rule for subpart W requires leak screening of standard components such as the ones described above with a gas imaging camera and nothing else. This mandate is difficult to comprehend, and an onerous one at that, given the enormous advantages of leak screening with both conventional technology and even newer better technologies also described above.
The fallacy of this mandate is that the gas imaging camera is an effective tool for this application when in fact it is just the opposite. The time it takes to effectively screen a thousand or more components is easily twice the time and as much as four times longer when compared with an infrared active laser leak detector. Perhaps a better use of the camera would be to stick with the vented components since the infrared laser must have a proper reflective background in order to screen a component successfully. Application of these technologies is critical to insuring the proper use and success of both these devices. Limiting the operator to one screening device is to limit the effectiveness of the survey which in this case will yield poor results while increasing the time and cost of the proposed survey.

Response: EPA has evaluated alternative methods for detection of equipment leaks for their viability and comparative accuracy to the optical gas imaging instrument in the proposed rule. In today's rule, EPA requires leak detection using one of several methods available, besides the option of an optical gas imaging instrument. EPA is still requiring that inaccessible sources use optical gas imaging instruments due to potential safety and cost concerns related to leak detection of sources that cannot be physically accessed from a fixed, supportive surface with a hand held leak detection device such as OVA/TVA, or which do not have a reflective background for an IR laser detection device. For further details, please see Section II.F of the preamble to today's final rule.

13.1 EMISSION FACTORS

Comment Number: EPA-HQ-OAR-2009-0923-1167-40
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

<u>Comment Excerpt Text:</u>

- The flare N2O emission factor in Table W-8 is based on MMCf gas production. An emission factor based on volume of gas combusted would be more appropriate.

Response: In the final rule, EPA has replaced the proposed rule's flare stack N_2O emission factor with a more accurate methodology to quantify N_2O emissions; please see the response to EPA-HQ-OAR-2009-0923-1027-11.

Comment Number: EPA-HQ-OAR-2009-0923-1059-9
Organization: Montana-Dakota Utilities Co.
Commenter: Abbie Krebsbach

<u>Comment Excerpt Text:</u>
The emissions factors that EPA requires to be used in calculating GHG emissions from natural gas systems were developed more than a decade ago by the Gas Research Institute (GRI). GRI used 10 year old data at that time and the data was only from a limited amount of pipeline components. These emissions factors were used to determine a ballpark estimate of nationwide GHG emissions from natural gas systems, and the intent was not to use them in accurately estimating individual company or source specific emissions that could potentially be used in future compliance with climate change legislation or regulation.

Response: EPA disagrees that emission factors were solely developed from the GRI reports. EPA's use of the GRI reports was governed by the lack of better publicly available data. In fact, both the GRI studies and Canadian studies were used to develop emission factors for natural gas distribution facilities. EPA has documented the data in the Canadian studies and the derivation of emission factors in the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Revisions to Processing Leaker Emission Factors in Rule Table W-2." and the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027)..

Comment Number: EPA-HQ-OAR-2009-0923-1299-5
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

<u>Comment Excerpt Text:</u>
Accuracy of Emission Factors

NGA questions the accuracy and validity of the proposed emission factors and their application. The proposed method of applying these emission factors to determine applicability or emission rates in our view will require clarification.

We would also recommend that the proposed emission factors be peer-reviewed to determine applicability, particularly to the LDC system.

Like AGA, we are concerned that EPA is planning to use emission factors that were developed over a decade ago for another purpose - and that were based on limited field work conducted nearly 20 years ago. Changes and upgrades on the distribution system are not reflected within these numbers and raise concerns about validity.

Finally, flexibility should be built into the rule to provide for updates when new emission factors become available.

Response: EPA disagrees that the emission factors in the rule are not accurate or valid. The commenter has not provided sufficient details on what clarification EPA should provide on the application of emissions factors. EPA used the best publicly available data to develop the emission factors for natural gas distribution systems in today's final rule. EPA has documented its derivation of emission factors used in the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Revisions to Processing Leaker Emission Factors in Rule Table W-2." EPA deemed the use of leaker emission factors, and the associated data quality, sufficient to inform future policy. If new and improved emission factors become available, at an appropriate time, EPA may re-propose applicable parts of subpart W. In addition, EPA will evaluate the natural gas distribution data received through the MRR, which are based on emission factors and methodologies in subpart W. EPA will also evaluate other emission factors that EPA may receive. EPA may also consider using direct measurement of equipment leaks and vents if EPA finds that the natural gas distribution emissions data received through the MRR is insufficient to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-0049-11
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Finally, and ideally, EPA should postpone imposing Subpart W on LDCs until EPA and industry partners have completed our ongoing joint research & development work to update the existing emission factors. This work has been underway and has already produced updated information. The remaining work could take approximately three to four years to complete, depending on the resources available. It would be ironic and unfortunate if industry and agency resources had to be diverted from developing more accurate emission factors in order to cope with the costs and burdens of applying the old emission factors under Subpart W. As EPA recognizes, the existing emission factors for our sector are outdated. They were developed a decade ago based on testing facilities and equipment nearly 20 years ago. Distribution systems are different now, and generally much tighter than they were 20 years ago as a result of improvements in both materials and operational procedures. As a result, the existing emission factors tend to overstate the actual emissions from distribution systems. The best way to obtain the information EPA seeks is to complete the work to develop updated, more accurate emission factors.

Response: EPA disagrees with the assertion that reporting emissions from natural gas distribution facilities should be delayed until updated emission factors become available. The commenter has alluded to studies intended to improve emission factors for the LDCs. EPA recognizes that these studies are being conducted to improve emission factors. However, EPA is not willing to forfeit valuable data, intended to inform future policy. EPA will not postpone the finalization of subpart W in anticipation of the results of these studies. If new and improved emission factors become available, at an appropriate time chosen by EPA, EPA may re-propose applicable parts of subpart W. For this final rule though, EPA used the best publicly available data to develop emission factors for the natural gas distribution segment. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.   .

Comment Number: EPA-HQ-OAR-2009-0923-1020-4
Organization: Southwest Gas Corporation
Commenter: James F. Wunderlin

Comment Excerpt Text:
Cost of Improving Emission Factors

It is well known that the accuracy of existing emission factors varies by as much as 300% to 2,000%. There have been significant efforts made to improve those accuracies within the last two years by the American Gas Association and individual companies, such as Southwest. Southwest, in collaborating with the Gas Technology Institute (GTI), has conducted direct measurement programs to further enhance the base information for emission factors. The cost of this work and the time needed to do the work does not appear to be adequately addressed in the justification for the proposed rule.

EPA found that emission factors generated from the Clearstone studies related better to methane-rich stream fugitives and were more appropriate than other emission factors developed for highly regulated refinery and petrochemical plants on VOC emissions. Therefore, EPA is using emissions data from the Clearstone studies as the basis for the leaker factors proposed in this rule. Due to the extremely short comment period, Southwest does not have time to thoroughly evaluate the emission factors from the Clearstone studies. Southwest has no comfort that this alternative approach better estimates annual facility emissions without resulting in additional reporting burden to the facilities.

Response: EPA solicited data in its proposed rule but the commenter has not submitted different or improved emission factors. Furthermore, in developing emission factors for use in today's final rule, EPA conducted a thorough search of all publicly available documents to determine the best data to use to develop emission factors. EPA did not find the emission factors that the commenter is alluding to. In addition, EPA does not intend to use emission factors that are not publicly available. Consequently, EPA used the best available, public data to develop the emission factors for natural gas distribution facilities in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1299-5 for further details. EPA does not need to include in the rule's cost burden analysis the cost incurred by reporters to conduct their own emission measurement studies.

Comment Number: EPA-HQ-OAR-2009-0923-1306-16
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:

In addition to the challenges described above, postponing implementation of Subpart W would also allow the development of updated emission factors for distribution system equipment. This emission factor update is currently underway by AGA, EPA, and the Gas Technology Institute (GTI) and is expected to produce more accurate methane emission factors than the emission factors developed over a decade ago by the Gas Research Institute (GTI's predecessor) using data from testing a limited sample of equipment. The updated emission factors will be used to facilitate more accurate GHG emission estimates for plastic distribution pipe, metering and regulator (M&R) stations and other natural gas distribution equipment. This work is not expected to be complete until 2012 or 2013 depending on funding availability, but it has already produced a new emission factor for plastic distribution pipe that better reflects the extremely low leak rate for modern plastic pipe than the old, statistically questionable emission factor EPA is currently using to estimate emissions from natural gas distribution. Upon completion of this work, we expect combined GHG emissions from natural gas distribution systems across the country to be even lower than the already low estimate of less than 1% of total U.S. GHG emissions.

Response: The emission factors that the commenter cited were not submitted to EPA. Please see the response to EPA-HQ-OAR-2009-0923-1020-4 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1059-10
Organization: Montana-Dakota Utilities Co.
Commenter: Abbie Krebsbach

<u>Comment Excerpt Text:</u>
More accurate emissions factors are expected to be available in about 2012 to 2013 from studies that are currently in progress, involving the collaboration of AGA, GRI and EPA. MDU recommends that the EPA review the new emissions factors before requiring reporting of GHG fugitive emissions from natural gas systems with the outdated emissions factors and inadvertently creating long term erroneous climate policy determinations. The new emissions data being developed from the new study is demonstrating in some cases that the old emissions factors are overestimating emissions, such as in plastic pipe.

Response: EPA used the best publicly available data to develop emission factors for natural gas distribution facilities. Please see the response to EPA-HQ-OAR-2009-0923-0049-11. If new and improved emission factors become available, at an appropriate time, EPA may re-propose applicable parts of subpart W. Please see response to comment EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-1082-15
Organization: MidAmerican Energy Holdings Company
Commenter:

<u>Comment Excerpt Text:</u>
EPA requests comments on the use of emission factors from the Clearstone studies. For further

details see Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923).

MidAmerican believes that studies from the Interstate National Gas American Association (INGAA) have the most accurate and appropriate emission factors for natural gas transmission systems. MidAmerican recommends, as an option, that the EPA use the emission factors developed by INGAA.

Response: EPA disagrees with the commenter's suggestion to use emission factors developed by INGAA. The data used by INGAA to develop leaker emission factors is the same as the data used by EPA. However, INGAA's emission factors are directly from the report "Handbook for Estimating Methane Emissions from Canadian Natural Gas System" written by Clearstone Engineering Ltd. for the Canadian Energy Partnership for Environmental Innovation. EPA took this same data, in addition to other data collected by Clearstone Engineering Ltd., and developed emission factors using EPA's own methodology. EPA's emission factors are based on a larger data set than INGAA's emission factors. In addition, EPA was also able to segregate the data to develop compressor related and non-compressor related emission factors to more accurately quantify equipment leaks from onshore natural gas transmission compression. Further information on the development of leaker emission factors for onshore natural gas transmission compression can be found in the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Revisions to Processing Leaker Emission Factors in Rule Table W-2"

Comment Number: EPA-HQ-OAR-2009-0923-1099-7
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

<u>Comment Excerpt Text:</u>
Emission Factors - The emission factors EPA uses in Subpart W are outdated and therefore tend to overestimate actual emissions. EPA should postpone finalizing Subpart W until the emission factors are updated. If that is not possible the current research and development to update these emission factors should be a priority to complete in order to get the most accurate GHG inventory. In the event that updated factors are found to be lower, they should be applied retroactively to previous year's submissions.

Response: EPA disagrees with the commenter's recommendation to delay reporting of emissions. Please see the response EPA-HQ-OAR-2009-0923-0049-11. If EPA deems it necessary to more accurately estimate emissions from previous years for the purpose of informing future policy, then EPA will apply the updated emission factors to previous years' submissions.

Comment Number: EPA-HQ-OAR-2009-0923-1151-73
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
EPA is using emissions data from the Clearstone studies as the basis for the leaker factors proposed in this rule. EPA requests comments on the use of emission factors from the Clearstone studies.

Section VIII of this document details a comparison between the emission factors proposed for Subpart W and the API Compendium. API is not opposed to using emission factors developed from Canadian studies. However, emission factors specific to U.S. operations would be more appropriate. API is open to working with EPA to develop leaker emission factors specific to US operations. API also recommends that the reporting rule be flexible and allow the use of updated emission factors as they become available. In addition, the emission factors provided for Subpart W from the Clearstone studies are not in the cited reports. EPA should provide details on the emission factors cited for an open and transparent review by industry.

Response: EPA disagrees with the comment on how to update emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1299-5. EPA disagrees that the emission factors in the rule are not appropriate. EPA has documented the data in the Canadian studies and the derivation of emission factors in the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Revisions to Processing Leaker Emission Factors in Rule Table W-2" and the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027).

Comment Number: EPA-HQ-OAR-2009-0923-1168-9
Organization: Delmarva Power a PHI Company
Commenter: Wesley L. McNealy

Comment Excerpt Text:
Emission Factor Development

DPL is concerned that the emission factors utilized to calculate fugitive emissions in proposed Subpart W are dated and likely inaccurate. These emission factors are not only a decade old but were based on equipment and testing facilities nearly two decades ago. The aged proposed Subpart W emission factors do not account for more modern and tighter natural gas distribution systems. Use of these emission factors for GHG reporting will only lead to inflated fugitive emissions figures that are counterproductive to the vast resources utilized to achieve them.

Response: EPA disagrees that the emission factors in the rule are inaccurate. EPA used the best publicly available data in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-1176-3
Organization: Citizens Energy Group
Commenter: Ann W. Mclver

Comment Excerpt Text:
Citizens also urges EPA to reconsider the use [of] emission factors that are out of date as a result of technology innovations or other conditions. The use of unrepresentative factors may overestimate GHG emissions associated with fugitives from equipment, placing an unrealistic expectation on the total emissions reductions available from the sector. Citizens encourages EPA to work collaboratively with organizations to update these emissions factors, and to provide sufficient flexibility in the rules to allow the use of new or updated emission factors as they become available.

Response: EPA disagrees that the emission factor used in today's final rule are unrepresentative of current equipment and operations Regarding how emission factors may be updated in the rule, please see the response to EPA-HQ-OAR-2009-0923-1299-5 for more information.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-10
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Therefore, we urge you to postpone requiring fugitive emission reporting for natural gas distribution under Subpart W. Instead, AGA would like to finish the joint project we have undertaken with EPA and others to conduct field testing and to develop updated, modern, accurate emission factors for natural gas distribution. AGA and its members have already conducted work in this area and developed some emissions factors that are not reflected in this proposal. And we are committed to further improvements in emission factors.

Response: The emission factors that the commenter cited have not been submitted to EPA, and this work is not scheduled to be completed in the near future and therefore EPA cannot wait to finalize this rule after the factors are finished.   Please see the response to EPA-HQ-OAR-2009-0923-1020-4 for further details. EPA used the best publicly available data to develop emission factors for natural gas distribution facilities. Please see the response to EPA-HQ-OAR-2009-0923-0049-11. If new and improved emission factors become available, at an appropriate time, EPA may re-propose applicable parts of subpart W. Please see response to comment EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-8
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Third, we are concerned that your plan to use emission factors that were developed over a decade ago for another purpose by the Gas Research Institute, GRI, that were based on limited field work conducted nearly 20 years ago beginning in 1992 – we're concerned about that because many things have changed since then. Much of the old cast iron and steel pipe has been replaced or lined with new plastic pipe.

And modern plastic pipe has significantly lower fugitive emissions. Materials and construction methods and practices for operations have changed as well and improved. As you know, over the past decade, our members have been working with your EPA Natural Gas STAR program with Roger Fernandez who's here some place in the audience. And we're working through that program to develop and implement practices that make our systems tighter. Well, that work has been going on, but those emission factors have not changed in the meantime. Those old emissions factors represent an old snapshot in time and they do not reflect reality now. And they tend to vastly overstate emissions from modern, tighter natural gas distribution.

Response: EPA disagrees that any industry wide changes in the materials used to make or replace pipes will produce a change in emission factors. The data used to develop these factors track the pipe material; therefore, the emission factors are material specific.

EPA appreciates the participation of Partners in the Natural Gas STAR program. However, there are significant differences between the Natural Gas STAR program and intent of today's final rule. Partners in the program report reductions in emissions using non-standardized methodologies resulting in data that cannot adequately inform future policy. EPA's intent with today's final rule is to monitor and report greenhouse gas emissions from the petroleum and natural gas industry using methodologies that balance burden with data quality, while providing sufficient data to inform future policy.

EPA used the best available, public data to develop the emission factors in Table W-1 through W-7 of today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1299-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1074-19
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
75 FR 18647-18650: Tables W-1 through W-8

Comment: WBIH strongly recommends that fugitive emission factors provided in the proposed rule, Tables W-1 through W-8, be moved to a separate EPA guidance document, incorporated by reference into the rule; and, recommends flexibility in the use of fugitive emission factors (leaker factors, component counts, equipment specific factors, and field-specific factors (developed at the field level) for emissions quantification at onshore petroleum and natural gas production, and onshore natural gas transmission compression facilities and underground natural gas storage facilities.

Emission factors for fugitive emissions are not consistent between current guidance documents, creating significant potential for fugitive emissions data inaccuracies. However, the use of emission factors has to remain flexible so factors can be applied to most closely match component operation and are consistent with current air quality permitting programs.

Additionally, emission factors should be provided in a separate guidance document which will facilitate changes without the need for a rule change.

Response: EPA disagrees with the suggestion to remove the emission factors from subpart W and placing them in another referenced technical document. If the emission factors are updated in the referenced technical document, then Subpart W will still have to be re-proposed. As a result, there is no efficiency gain to updating emission factors in a separate document versus having the factors in the rule itself. EPA disagrees with the comment to allow reporters to choose methods that are not specified in subpart W. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98) and the response to EPA-HQ-OAR-2009-0923-1151-9.

Comment Number: EPA-HQ-OAR-2009-0923-1167-28
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Flexibility to use alternative "best available" emission estimation methods is needed to avoid unnecessary burden while ensuring quality data. Noble recommends that the emission factors in Subpart W tables should be moved to a separate EPA reference document that is incorporated into the rule by reference.

Response: EPA disagrees with the recommendation to provide the emission factors in a referenced technical document. Please see the response to EPA-HQ-OAR-2009-0923-1074-19.

Comment Number: EPA-HQ-OAR-2009-0923-1167-34
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
In addition, Noble strongly recommends that the emission factors in Subpart W tables (e.g., Tables W-1 and W-2) should be moved to a separate EPA reference document (such as or similar to AP-42 emission factors) that is incorporated into the rule by reference. Reopening a rule to update emission factors would be difficult to accomplish and introduce unnecessary delays resulting in outdated emission factors. A separate EPA reference document should be developed and subjected to a peer review process. Subsequent updates will facilitate emission factor improvements and refinements from new and improved data that are collected and compiled. This reference document can be periodically revisited and updated to ensure that the best available data and emission factors are being used.

Response: EPA disagrees with the comment on how to update emission factors. EPA used the best publicly available data to develop emission factors for natural gas distribution facilities. Please see the response to EPA-HQ-OAR-2009-0923-1074-19.

Comment Number: EPA-HQ-OAR-2009-0923-1197-8
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

Comment Excerpt Text:
Emission factor update - The emission factors (EFs) should not be included in the proposed rule because they are mostly outdated and should be updated. Companies must be provided the flexibility and given reasonable time to develop more accurate EFs using current technologies.

Response: EPA disagrees with the recommendation to not include emission factors in the rule to allow for emission factor updates. Please see the response to EPA-HQ-OAR-2009-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-1024-51
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
TABLE W-1 OF SUBPART W–DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore *petroleum and natural gas* production	Emission Factor (scf/hour/component)
Population Emission Factors - All Components, Gas Service	
Valve	0.08
Connector	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
~~Gathering Pipelines1~~	~~2.81~~
~~CBM Well Water Production2~~	~~0.11~~
Population Emission Factors - All Components, Light Crude Service3	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other5	0.24
Population Emission Factors - All Components, Heavy Crude Service4	
Valve	0.001
Flange	0.001
Connector (other)	0.0004
Open-ended Line	0.01
Other5	0.003

~~1 Emission Factor is in units of "scf/hour/mile"~~

~~2 Emission Factor is in units of "scf methane/gallon", in this case the operating factor is "gallons/year" and do not multiply by methane content~~

3 Hydrocarbon liquids greater than or equal to 20°API are considered "light crude"

4 Hydrocarbon liquids less than 20°API are considered "heavy crude"

5 "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

TABLE W-2 OF SUBPART W–DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING PLANTS

Onshore natural gas processing plants~~Processing~~	Before De-methanizer Emission Factor (scf/hour/component)	After De-methanizer Emission Factor (scf/hour/component)
Leaker Emission Factors - Reciprocating Compressor Components,		
Processing	Before De-methanizer Emission Factor (scf/hour/component)	After De-methanizer Emission Factor (scf/hour/component)
Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors - Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Dry Seal	105	105
Leaker Emission Factors - Other Components, Gas Service		
Valve	6.42	
Connector	5.71	
Open-ended Line	11.27	
Pressure Relief Valve	2.01	
Meter	2.93	
~~**Population Emission Factors - Other Components, Gas Service**~~		

~~Gathering Pipelines1~~	~~2.81~~

~~1 Emission Factor is in units of "scf/hour/mile"~~

TABLE W-3 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR FIELD GATHER AND/OR BOOSTING STATIONS AND ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Field gathering and/or boosting stations and onshore natural gas transmission compression~~*Transmission*~~	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

TABLE W-4 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND Natural Gas STORAGE

Underground *Natural Gas* Storage	**Emission Factor (scf/hour/component)**
Leaker Emission Factors - Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

TABLE W-5 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG Storage	**Emission Factor (scf/hour/component)**
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other1	1.77
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	6.81

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

TABLE W-6 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT TERMINALS

LNG *Import and Export Equipment* ~~Terminals~~	**Emission Factor (scf/hour/component)**
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	1.19
LNG Terminals	**Emission Factor (scf/hour/component)**
Pump Seal	4.00
Connector	0.34
Other	1.77
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	6.81

TABLE W-7 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

***Natural Gas* Distribution**	**Emission Factor (scf/hour/component)**
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors - Below Grade M&R Stations Components, Gas Service1	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure < 100 psig	0.10
Population Emission Factors - Distribution Mains, Gas Service2	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors - Distribution Services, Gas Service2	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

1 Emission Factor is in units of "scf/hour/station"
2 Emission Factor is in units of "scf/hour/service"

TABLE W-8 OF SUBPART W–DEFAULT NITROUS OXIDE EMISSION FACTORS FOR GAS FLARING [see original in pdf attachment]

Gas Flaring	Emission Factor (metric tons/MMscf gas production or receipts)
Population Emission Factors - Gas Flaring	
Gas Production	5.90E-07
Sweet Gas Processing	7.10E-07
Sour Gas Processing	1.50E-06
Conventional Oil Production1	1.00E-04
Heavy Oil Production2	7.30E-05

1 Emission Factor is in units of "metric tons/barrel conventional oil production"

2 Emission Factor is in units of "metric tons/barrel heavy oil production"

Response: EPA agrees, and in today's final rule, the title of the tables have been changed as suggested by the commenter. EPA deems the changes necessary to clarify the industry segment for which the emission factors are applicable.

Gathering pipelines are not required to report emissions in today's final rule; please see Section II.F of the preamble to today's final rule for a response to this comment.

Reporting of coal bed methane well water production is not required in today's final rule. Upon further analysis, EPA determined that this source is not significant enough to be included in today's final rule. Please see the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027). The emission factor has been removed accordingly.

Comment Number: EPA-HQ-OAR-2009-0923-1031-10
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
The proposed calculation for gas gathering pipelines is impractical. EPA is proposing to not include reporting of fugitive emissions from natural gas transmission pipelines due to the dispersed nature of the fugitive emissions and the fact that once leaks are found, the emissions are generally addressed quickly. EPA fails to use this same logic for natural gas gathering pipelines, which are significantly more dispersed than transmission pipelines. Gas gathering lines are generally much smaller diameter and typically operate at much lower

pressures than transmissions lines, resulting in a lower potential for emissions. Some gathering pipelines even operate on a vacuum. It is also important to note that many gathering and processing companies have implemented robust programs to find and fix pipelines leaks. Contrary to the transmission pipelines, EPA appears to propose that gas processing plants and producers conduct a physical count of piping components on gathering lines and use population factors to determine emissions. Operators then apply another factor (scf/hour/mile) to calculate GHG emissions from the pipeline segments.

GPA estimates that there are over 250,000 miles of gathering pipelines in the gathering and processing sector, and hundreds of thousands of meter and valve settings, that would require physical component counts. Even more impractical, is the requirement to conduct compositional analysis at these sites to determine methane and CO2 concentrations. Further, operators would have to track blowdowns and changes in small meter runs and pipe segments in these hundreds of thousands of insignificant locations to report GHGs as required by proposed Subpart W.

Response: Gathering pipelines are not required to report emissions in today's final rule. Please see Section II.F of the preamble to today's final rule for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1031-15
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
Lastly, for entities who must report emissions from gathering lines, the emissions should be calculated simply as the product of miles of gathering lines times an appropriate per mile emissions factor. This value should be reported as a total for each company, rather than being reported on a source or facility basis. Lastly, to accommodate this reporting method, the rule should allow companies to use an overall estimate of CO_2 and CH_4 content.

Response: Gathering pipelines are not required to report emission in today's final rule; please see Section II.F of the preamble to today's final rule for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-134
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Further, as a separate sub-sector, API recommends the use of the default emission factor for gathering pipelines, as provided in Table W-1. Natural gas gathering pipelines are widely dispersed, are generally much smaller diameter, and typically operate at low pressures, resulting in a lower potential for emissions. Some gathering pipelines even operate on a vacuum. Emissions from the gathering lines are a small fraction of the total 224 million metric tons attributed to the OPGP sector. According to information from the Gas Processors Association (GPA), the total length of gathering pipeline in the lower 48 (L48) states is about 250,000 miles.

Using the calculation methodology in the proposed rule (emission factor of 2.81 scf of CH_4/hr/mile) the CO_2eq emissions for all L48 gathering lines is about 2.0 million metric tons, i.e., less than 1% of the EPA projected OPGP sector's GHG annual emissions. Therefore, a default emission factor is appropriate.

Response: Gathering pipelines are not required to report emission in today's final rule; please see Section II.F of the preamble to today's final rule for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1206-14
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
It is also noted that the emission factor for the gathering pipeline segments (2.81scf/hour/miles) is derived from an unexplained total pipeline emission estimate of 6.6 Bscf. See TSD at 147-148. GPA suggests that if EPA has already established this emission estimate, they should simply add it to the rolled-up GHG inventory for the natural gas industry rather than requiring operators to expend significant resources re-creating the exact same number.

Response: Gathering pipelines are not required to report emissions in today's final rule; please see Section II.F of the preamble to today's final rule for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-130
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Emission Factor Comparison to the API Compendium

API supports the use of emission factors from the API Compendium, as these are widely used and accepted by the oil and natural gas industry worldwide. API compared the emission factors provided in Tables W-1 through W-7 to the API Compendium. The following summarize this comparison. Tables at the end of this section show the numeric comparison of EPA's proposed emission factors versus API Compendium emission factors. Errors and recommendations for specific emission sources are noted below.

General Comment

- The TSD shows a CH_4 density being applied to emission factors that are on a TOC or THC basis. This error should be corrected and would be avoided if the Subpart W emission factors were provided on a mass basis.

Onshore Production

- For Onshore Production gas service, the TSD cites the GRI/EPA study (Methane Emissions from the Natural Gas Industry. Volume 8. Tables 4-3, 4-6 and 4-24, June 1996) for the gas service fugitive emission factors for onshore production. These emission factors were compared to API Compendium Table 6-12, which cites EPA's Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-4). This comparison is provided in Table VIII-1 below. The API Compendium emission factors are higher than those provided in Table W-1 for valves and open-ended lines. The values are the same for connectors. For these factors, the TSD combines the Western US and Eastern US data from the GRI/EPA study to develop the emission factors. It would be more appropriate to weight the geographical region factors by the representative portion of the total US production so as not to bias any one geographical area. However, API supports using the emission factors cited in the API Compendium, which are generally more conservative than the proposed emission factors.

- Table W-1 labels the emission factors by service: gas, light crude and heavy crude. API Compendium Table 6-12 presents fugitive emission factors by service type based on EPA's Protocol for Equipment Leak Estimates (EPA-453/R-95-017). However, the emission factors are more comparable to API Compendium Table 6-14 factors (from API 4615), which are based on facility type. The tables in Subpart W do not explain this, as they refer to the factors as service based factors. This could lead to erroneous application of the emission factors. Please refer to Table VIII-1 for the comparison of gas service components, and Table VIII-2 for the comparison of light crude and heavy crude service. Based on this comparison, it appears the emission factors in Table W-1 are misrepresented as service-specific factors and should instead be described as facility-specific factors. Here also, API supports using the emission factors cited in the API Compendium.
- The light and heavy crude oil service emission factors from Table W-1 match the average emission factors provided on pages 146 and 147 of the TSD (Appendix L), which cites API, Emission Factors for Oil and Gas Production Operations (Table 9, page 10), API Publication Number 4615, January 1995. However, when converting the total gas emission factors to an scf basis, the TSD incorrectly multiplies the original API emission factors by the CH_4 content and then divides by the CH_4 density. The original total gas emission factors should instead just be divided by the natural gas density to calculate the total gas emission factor from a mass basis to an scf basis. This error should be corrected and would be avoided if the emission factors were provided on a mass basis. With this correction, the emission factors should match those from the API Compendium.

Gas Processing

- The references cited in the TSD do not provide the emission factors shown in the TSD. The TSD cites EPA. Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants. Clearstone Engineering Ltd. June 20, 2002. www.epa.gov/gasstar/documents/four_plants.pdf and National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd; Innovative Environmental Solutions, Inc. Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. For EPA Natural Gas STAR Program. March 2006. EPA should provide details on the derivation of the emission factors provided in Table W-2. In addition, API could work with EPA in the future to develop leaker emission factors specific to US operations.

- The cited reports provide average emission factors, and do not break them out by “reciprocating compressor”, “centrifugal compressor,” and “other components”. The reports do provide detailed tables for all measurements conducted in the study, but not with the information needed to derive the emission factors presented in the TSD. EPA should provide details on the derivation of the emission factors provided in Table W-2.
- Emission factors from API Compendium Table 6-15 (shown in Table VIII-2 below) cite the same reference as the TSD. However, as noted above, a comparison can only be made for the “Other Components-Gas Service” shown in Subpart W Table W-2. EPA should provide details on the derivation of the emission factors provided in Table W-2.

Transmission, Storage, and Distribution

- The API Compendium does not provide leaker emission factors specific to transmission, storage and distribution, so a direct comparison is not possible. API could work with EPA in the future to develop leaker emission factors specific to US operations.
- For pneumatic controllers, Tables W-3 and W-4 presents the low-bleed emission factor from onshore production. The API Compendium provides emission factors specific to pneumatic devices observed in transmission and storage operations. The pneumatic controller emission factors for transmission and storage should be corrected to apply factors specific to those sectors rather than apply factors developed for production operations. API recommends using the sector appropriate pneumatic controller emission factors from the Compendium.
- The “leaker” emission factors provided in Tables W-4 and W-7 are taken from Appendix K of the TSD (page 142) without references or derivations. Therefore, it is not possible to evaluate these emission factors. EPA should provide details on the derivation of the emission factors provided in Tables W-4 and W-7.
- The “regulator” and “open-ended line” emission factors provided in Table W-7 do not match the emission factors shown on page 142 of the TSD. It appears that the “regulator” emission factor from the TSD was assigned to the “open-ended line” in Table W-7. This error should be corrected.
- As shown in Table VIII-3, the emission factors for the below grade M&R Stations, distribution mains, and distribution services compare well with the API Compendium. API supports the use of emission factors consistent with the API Compendium.
- The units shown for the distribution mains emission factors should be scf CH_4/mile-yr, not scf CH_4/service-yr. This error should be corrected. With this correction, the emission factors compare well with the API Compendium emission factors, as shown in Table VIII-4.

LNG Operations

- The emission factors provided in Table W-5 are derived from oil and gas production light liquid emission factors and are not specific to LNG operations. The API Compendium does not provide LNG emission factors to compare with Subpart W. The API Compendium notes (p. 2-16) that CH_4 emission factors for LNG vents are not well developed. LNG systems are designed to avoid contact with the outside air and great effort is taken to prevent vented and fugitive losses. API recommends excluding emission estimates for LNG operations until LNG-specific emission factors are developed.
- Table W-5 provides an emission factor for “vapor recovery compressors” in units of scf CH_4/component-hr. The methane emissions per compressor are from the EPA Inventory

of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007. The TSD shows the original emission factors as 100 scfd CH_4/compressor and applies a “CH_4 content of onshore light crude associated gas” that is actually the weight fraction of CH_4 for light crude service components in production. This error should be corrected.

Flare N_2O Emission Factors

- Table W-8 provides N_2O emission factors for flares, which match values provided in API Compendium Table 4-11. However, the API Compendium notes that very little information is available for N_2O emissions from flares. The factors cited by Subpart W and the API Compendium are from IPCC, which provides a 95% uncertainty bound of -10% to +1000% for these factors. Due to the inaccuracies and insignificant contribution, API recommends that N_2O emissions from flares be excluded from Subpart W.
- The units for “sweet gas processing” and “sour gas processing” should be tonnes/MMscf of raw gas feed. This error should be corrected. However, due to the inaccuracies and insignificant contribution, API recommends that N2O emissions from flares be excluded from Subpart W.

Table VIII-1. Production Gas Service Emission Factor Comparison

Source Type	EPA MRR Subpart W	API Compendium	Units
Onshore Production - Gas Service		Compendium Table 6-12 Service specific factors	
Valve	0.08	0.19	scf gas/component-hr
Connector	0.01	0.01	scf gas/component-hr
Open-ended Line	0.04	0.08	scf gas/component-hr
Pressure Relief Valve	0.17	0.02	scf gas/component-hr
		Compendium Table 5-15	
Low-Bleed Pneumatic Device Vents	2.75	1.39	scf gas/component-hr
		Compendium Table 6-4	
Gathering Pipelines	2.81	2.83	scf gas /hour/mile
CBM Well Water Production	0.11	Not included	scf methane/gallon

Table VIII-2. Production Crude Service and Processing Emission Factor Comparison

Source Type	EPA MRR Subpart W	API Compendium	Units	API Compendium	Units
Onshore Production - Light Crude Service		Compendium Table 6-12 Service specific factors		Compendium Table 6-14 Facility specific factors	
Valve	0.04	0.10	scf gas/component-hr	0.05	scf gas/component-hr
Connector	0.01	0.01	scf gas/component-hr	0.01	scf gas/component-hr
Open-ended Line	0.04	0.06	scf gas/component-hr	0.05	scf gas/component-hr
Pump	0.01	0.52	scf gas/component-hr	0.01	scf gas/component-hr
Other	0.24	0.30	scf gas/component-hr	0.30	scf gas/component-hr
Onshore Production - Heavy Crude Service		Compendium Table 6-12 Service specific factors		Compendium Table 6-14 Facility specific factors	
Valve	0.001	0.00042	scf gas/component-hr	0.00066	scf gas/component-hr
Flange	0.001	0.00002	scf gas/component-hr	0.00110	scf gas/component-hr
Connector (other)	0.0004	0.00038	scf gas/component-hr	0.00040	scf gas/component-hr
Open-ended Line	0.01	0.00705	scf gas/component-hr	0.00781	scf gas/component-hr
Other	0.003	0.00161	scf gas/component-hr	0.00352	scf gas/component-hr
Gas Processing - Leaker Emission Factors - Other Components, Gas Service		Compendium Table 6-15 (Average EFs from EPA/Clearstone)		Compendium Table C-2 (Screening Factors >10,000 ppm)	
Valve	6.42	1.91	scf THC/component-hr	3.25	scf TOC/component-hr
Connector	5.71	0.17	scf THC/component-hr	1.44	scf TOC/component-hr
Open-ended Line	11.27	12.16	scf THC/component-hr	1.54	scf TOC/component-hr
Pressure Relief Valve	2.01	0.02	scf THC/component-hr	Not addressed in the Compendium	
Meter	2.93	0.14	scf THC/component-hr	Not addressed in the Compendium	
Other				3.70	scf TOC/component-hr

Table VIII-3. Distribution M&R Station Emission Factor Comparison

Source Type	EPA MRR Subpart W	API Compendium	Units
Below Grade M&R Station > 300 psig	1.3	1.3	scf CH4/station-hr
Below Grade M&R Station 100-300 psig	0.2	0.18	scf CH4/station-hr
Below Grade M&R Station <100 psig	0.1	0.0865	scf CH4/station-hr

Table VIII-4. Distribution Pipeline Emission Factor Comparison

Source Type	EPA MRR Subpart W	API Compendium	Units
Distribution Mains			
Cast Iron	27.25	27.14	scf CH4/mile-yr
Plastic	1.13	1.87	scf CH4/mile-yr
Protected Steel	0.35	0.35	scf CH4/mile-yr
Unprotected Steel	12.58	12.53	scf CH4/mile-yr
Distribution Services			
Unprotected Steel	0.19	0.19	scf CH4/service-hr
Protected Steel	0.02	0.02	scf CH4/service-hr
Plastic	0.001	0.001	scf CH4/service-hr
Copper	0.03	0.03	scf CH4/service-hr

Response: EPA agrees that methane density should not be used to convert total hydrocarbon emission factors with units of pounds per component per day to standard cubic feet per component per day. In today's final rule, the conversion was completed using an average density for natural gas.

EPA disagrees with the comment to weight the onshore production emission factors. EPA used the same data as API used to derive its emission factor for gas services, which is the GRI/EPA study (Methane Emissions from the Natural Gas Industry, Volume 8, June 1996), However, EPA determined that the emission factors and the operational characteristics for onshore production facilities in the two geographical regions differ sufficiently to justify a separation. As a result, the emission factors for onshore production in today's final rule are for the eastern and western regions of the U.S. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Equipment-Level Population Emission Factors for Onshore Production".

EPA clarifies that the use of "service-type" is synonymous with API's use of "facility type" in API Publication Number 4615. Thus, the text in Table W-1A remains unchanged in today's final rule.

EPA agrees with the commenter that the API compendium does not have leaker emission factors for the onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution segment. However, EPA used the best, publicly available data to derive its leaker emission factors for these segments of the petroleum and natural gas industry. EPA provided derivation of leaker emission factors found in Tables W-2, W-3, W-4, and W-7 in the rulemaking docket (EPA-HQ-OAR-2009-0923). In the docket, EPA provided these data, a description of the methodology employed, and the resulting emission factors. The leaker emission factors in Table W-2, W-3, W-4, and W-7 in the final rule are not directly from the cited reports. EPA used the raw data from these reports and a methodology different from these reports that tailors leaker emission factors to the final rule. These methodologies, employed to derive the emission factors in Table W-5, W-6, and W-7, are available in Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Technical Support Document (TSD) found in docket (EPA-HQ-OAR-

2009-0923-0027) and "Revisions to Processing Leaker Emission Factors in Rule Table W-2" of the rule making docket (EPA-HQ-OAR-2009-0923).

EPA agrees that the emission factors for regulators and open ended lines in distribution listed in the Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027)do not match those provided in Table W-7. EPA has revised the Background Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923) to match the emission factors in Table W-7.

EPA agrees with the commenter's suggested correction to Table W-7 in the proposed rule, and today's final rule text was revised. The unit for distribution mains has been changed to standard cubic feet per hour per mile of distribution main (scf/hour/mile).

EPA agrees that the API compendium includes a pneumatic device emission factor specific to the transmission sector. However, this emission factor does not differentiate high-bleed pneumatic devices from low-bleed pneumatic devices. EPA is requiring this level of specificity from pneumatic devices to inform future policy. As a result, EPA is retaining the use of its emission factors for pneumatic devices in the transmission sector in today's final rule.

EPA disagrees with the commenter on excluding LNG facilities and has retained the requirements for reporting. LNG facilities in most cases handle natural gas and hence are liable to equipment leaks just like in other gas handling facilities. EPA reiterates that the goal of the Final Mandatory GHG Reporting Rule ("Final MRR") (40 CFR part 98) is to quantify emissions from major sources in the petroleum and natural gas industry. EPA's criteria are clearly outlined in the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027) under 'Selection of emissions sources for reporting.' EPA used the best publicly available data to develop emission factors in today's final rule. In addition, EPA will evaluate the LNG facility data received through the MRR, which are based on emission factors and methodologies in subpart W. EPA will also evaluate other emission factors that EPA may receive. EPA may also consider using direct measurement of equipment leaks and vents if EPA deems the LNG facility emissions data received through the MRR is insufficient to inform policy.

EPA agrees that the units for the emission factor for vapor recovery compressors should be standard cubic feet per hour per compressor (scf/hour/compressor) and has revised it accordingly in today's final rule. In addition, EPA agrees with the comment regarding the application of the weight fraction of CH_4 for light crude service components in production to convert the original emission factor, and EPA has revised this by removing this weight fraction.

In today's final rule, EPA has replaced the proposed rule's flare stack N_2O emission factor with a more accurate methodology to quantify N_2O emissions; please see the response to EPA-HQ-OAR-2009-0923-1027-11. All emissions using this methodology will be calculated in units of metric tons N_2O emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1039-17
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Fugitive Emissions – INGAA is Receptive to the Proposed Approaches but Revisions and Refinements are Needed to Add Flexibility and Clarity, and Facilitate Improvements

For fugitive emission estimates from natural gas transmission and storage, the breadth of the fugitive leak survey program, the basis for emission factors (EFs), and prescriptive technology requirements are cause for concern. Although EPA has reduced direct measurement requirements in the re-proposed Rule, it continues to mandate leak screening. INGAA is willing to accept the survey approach and proposed EFs at this time, but several revisions and clarifications are needed to make this a workable approach, including:

- Emission factors should be moved to a separate EPA technical document and incorporated by reference to facilitate EF improvement;
- Alternatives to the optical gas imaging instrument (also referred to as "optical camera") should be allowed for leak screening;
- Practices and procedures for the optical camera developed for VOC leaks from other industrial sectors should be revised to appropriately address methane leak surveys from natural gas transmission and storage sources;
- Provisions for eliminating or decreasing the frequency of leak screening should be adopted if data and/or EF advances meet accuracy needs or leak screening data indicates that intervals can be increased; and,
- To eliminate ambiguity, definitions and clarification are needed for component types and associated criteria for conducting a leak survey.

A. Emissions Factors Should Be Published in a Separate EPA Technical Document and Incorporated By Reference to Facilitate Emission Factor Updates

INGAA strongly recommends that emission factors (EFs) in Subpart W tables (e.g., Table W-3 and W-4) should be moved to a separate EPA reference document that is incorporated into the rule by reference. Reopening a rule to update emission factors would be difficult to accomplish and is a time consuming activity, resulting in outdated EFs. Thus, a separate EPA reference document should be developed and maintained. Review and updates would still require public involvement and peer review, but this approach will facilitate EF improvements and updates as new data are collected and compiled. This reference document can be periodically revisited and updated to ensure that best available data and EFs are being used.

A supplemental technical document incorporated by reference provides a means to advance state-of-the-science without requiring onerous rule revision / re-opening. Impeding more accurate natural gas systems emissions reporting due to the rule revision process will preclude timely updates and changes to the EFs necessary to advance the state-of-the-science and facilitate informed decisions on fugitive emissions.

The Proposed Subpart W emission factors are questionable in some cases. For example the compressor blowdown valve leaker EF is more than an order of magnitude greater than any component EF listed in Table W-3. This value is significantly higher than the value of 276.4 scf/hour per component listed in the 2007 Canadian Best Management Practices and 61.8 scf/hour per component listed in the INGAA Guidelines. A separate peer-reviewed EF document that contains background data used to develop the EF should be provided for all listed components.

Additional questions and concerns arise from the application of EFs that were developed using methods (i.e., Method 21) to detect leaks other than the optical camera. No credible study or technical analysis has been completed to support the application of the leaker EFs in Table W-3 and W-4 to leaks identified using the optical camera. The Method 21 approach and optical camera have different sensitivities. These differences and the potential implications on fugitive emissions estimate accuracy have not been reconciled. Therefore, it is conceivable that near-term updates to EFs will be desirable based on either a more in-depth understanding of the EPA-sanctioned EFs or an exponential growth of near-term data as rule requirements are implemented.

EF studies have recently occurred and recently initiated studies are ongoing. INGAA, EPA, and other stakeholders have been engaged in programs to improve EFs and such efforts should not be undermined (e.g., University of Texas-Austin study, US EPA Cooperative Agreement no. XA-83376101UTx, which includes natural gas transmission participation). As discussed below, EF projects should be undertaken with the goal and objective of improving current EFs and ultimately simplifying or replacing annual leak surveys. For example, additional data could document an alternative survey frequency or a need to focus on facility subsystems, such as components in vibration or heat-cycle service that are more prone to leak.

In addition, Final Rule text and associated equations that reference EFs should be generically written. For example, at a future point in time, alternative EFs may be desired that are population-based to replace the currently-proposed leaker EFs (or vise versa). The separate EPA technical document can provide the EFs and the context (e.g., activity data needs) for emission calculations. Restricting some fugitive estimate approaches to leaker-only EFs and restricting all emission factors to those published in the Rule will be too restrictive and will suppress innovation and improvements in the accuracy of GHG emission reports.

Response: EPA disagrees with the commenter’s contention to move the emission factors to a separate document. Please see the response to EPA-HQ-OAR-2009-0923-1074-19 for further details. EPA disagrees with the recommendation to not include emission factors in the rule to allow for emission factor updates. Please see the response to EPA-HQ-OAR-2009-1299-5. EPA disagrees with eliminating or decreasing the minimum annual leak screening to calculate emissions. Annual reports must be calculated and submitted each year; please see Section II.H of the preamble to The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98).

EPA recognizes the prevalence of multiple methodologies for leak detection and has included several additional leak detection techniques including flame ionization detectors, catalytic oxidation/thermal conductivity detectors, and soap solutions as per Method 21; please see Section II of the Preamble to today’s final rule for further details.

EPA disagrees that component definitions and leak detection methods are not in the rule. In today's final rule, component definitions in leak surveys are in either Section 98.6 or Section 98.238 of today's final rule. Methods for using leak detection equipment are in Section 98.234 of today's final rule.

EPA supports studies conducted by all stakeholders to improve emission factors. If updated emission factors become available through these studies, EPA may re-propose applicable parts of subpart W. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Upon further analysis and review, EPA determined there was insufficient data for Table W-3 for transmission leaker emission factors for compressor blowdown valves. Today's final rule has been revised and Table W-3 no longer has a compressor blowdown valve leaker emission factor. In today's final rule, the valve leaker emission factor in Table W-3 is for block valves and control valves. EPA has documented its derivation of emission factors used in today's final rule in the "Revisions to Processing Leaker Emission Factors in Rule Table W-2" memo.

EPA disagrees with the comment on the use of emission factors developed from studies using Method 21 and the application of the optical gas imaging instrument in the rule. EPA chose the optical gas imaging instrument in the Alternative Work Practice to 40 CFR parts 60, 63 and 65, and in today's final rule, is also allowing use of Method 21 for components within reach of a person standing on a fixed surface. The definition in today's final rule of a "leak" for Method 21 is 10,000 ppm by OVA/TVA, and the mass equivalent of that leak is 60 grams per hour. Since the optical gas imaging instrument can easily detect leaks well below the AWP, it is qualified. The explanation of the relationship between the 60 grams per hours leak threshold and various leak definitions is provided in EPA's Preamble to the AWP, and in docket EPA–HQ-OAR-2003-0199-0005.

Comment Number: EPA-HQ-OAR-2009-0923-3546-3
Organization: Texas Commission on Environmental Quality
Commenter: Mark R. Vickery

<u>Comment Excerpt Text:</u>
The TCEQ concurs with the use of fugitive factors for estimating emissions from leaking fugitives instead of direct monitoring to effectively reduce the emissions estimation and reporting burden. Their use, rather than direct monitoring, is considered acceptable practice in other industries. They may, however, be draft or out of date. A stated goal of the inventory is to lay a foundation for future regulatory action. The data collected reflects significant effort on the part of the reporting companies and may have significant impact on any future regulatory activities. Thus, accuracy of data remains a high priority and the TCEQ urges the EPA to update the factors in the rule as improved factors become available.

Response: EPA may re-propose applicable parts of the Subpart W, if EPA deems it necessary to update emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-0955-2
Organization: American Public Gas Association (APGA)
Commenter: Bert Kalisch

<u>Comment Excerpt Text:</u>
APGA supports estimating emissions using population and leaker emission factors. APGA supports EPA's proposal to allow fugitive methane emissions from LDC operations to be estimated based on population and leaker emission factors rather than by direct measurement. As EPA correctly notes, many of the leaks on natural gas distribution systems are on buried pipelines where it would be difficult, if not impossible, to directly measure leakage rates. APGA urges EPA to update these emission factors as more accurate data becomes available.

Response: EPA may re-propose applicable parts of the Subpart W, if EPA deems it necessary to update emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-3547-1
Organization:
Commenter: M. Harrison

<u>Comment Excerpt Text:</u>
Please allow the use of emission factors for compressor related components. EPA should not require direct measurements for all gas compressors. As the project manager of the GRI/EPA studies from the 1990's that are cited in the proposed rule, I am familiar with many of these emission measurements. The direct compressor measurements EPA is requiring for five fugitive and vented components at compressor stations are more technical, complex, and expensive to measure than EPA has estimated. Some emission sources are not possible to individually measure without physical modifications to the site. EPA should continue to fund research that refines the key natural gas emission factors. EPA should not require the entire industry to make measurements for a GHG reporting rule. EPA could allow for direct measurement as an alternative to emission factors, if the reporter elects, in their sole discretion.
Please allow for the use of scaled emission factors, rather than more detailed modeling that the proposed rule requires for sources like glycol dehydrators, amine units, and tanks. For the reporting rule purposes, the accuracy of scaled emission factors should be acceptable.

Response: EPA disagrees that it has underestimated the complexity and difficulty of quantifying emissions from compressor stations. EPA does not require complex physical modification to compressor equipment and is allowing acoustic leak detection devices to measure through valve leakages. Please see the response to comment EPA-HQ-OAR-2009-0923-1099-18. Compressors in the onshore petroleum and natural gas production segment of the industry use an emission factor to calculate emissions. Therefore not all segments of the industry are required to make measurements to determine emissions from reciprocating and centrifugal compressors. For further information please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Compressor Modes and Threshold". Glycol dehydrators, onshore production storage tanks and blowdown vents below set equipment thresholds can report emissions using a population emission factor in today's final rule. However, those emission sources above the equipment threshold are required to estimate emissions using more rigorous methodologies. For further information please see the response to EPA-HQ-OAR-2009-0923-1011-39, EPA-HQ-OAR-2009-0923-1060-10, and EPA-HQ-OAR-2009-0923-1061-12 for glycol dehydrator, onshore production storage tanks and blowdown vents, respectively. With regards to comment on funding research, EPA will consider participating in studies to improve emissions factors based on the priorities and budget of the Agency. EPA has allowed for alternative methods for data collection in certain cases where it was applicable and proven methodologies existed. EPA will consider adding direct measurement options for other sources when additional data comes available and at which time the Agency considers it appropriate in order to meet the goals of the mandatory reporting rule. It is unclear to EPA what the commenter meant with the term “scaled emissions factors.”

Comment Number: EPA-HQ-OAR-2009-0923-1018-39
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
In 98.233(p)(3) CAPP recommends emissions be estimated using average emission factors and annual hours for each of the operational modes. This is based on the large number of compressors this section is expected to affect (about 33000), and that as many as 18 annual measurements could be required for each (compressors typically have two to six compression cylinders and a measurement is required for three operating modes for each cylinder), resulting in a level of effort required to quantify these emissions that is out of balance with the overall contribution to the inventory.

Response: EPA agrees that some emissions from compressor components in different operating modes are similar and can be combined into a reporter based emission factor. Please see the response to comment EPA-HQ-OAR-2009-0923-1099-18.

Comment Number: EPA-HQ-OAR-2009-0923-1004-9
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
Providing simplified reporting methods – based on engineering estimation or emission factors, not direct measurement – for small components or units, such as small compressors and combustion devices, or low-throughput dehydrators and storage tanks;

Response: EPA agrees and has revised today’s final rule to allow glycol dehydrators, onshore production storage tanks, blowdown vents, and small external combustion units below a set equipment thresholds to report emissions using a population emission factor in today’s final rule. Today’s final rule has also been revised to allow reciprocating and centrifugal compressors in onshore petroleum and natural gas production to use an emission factor. For further information please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under “Equipment Threshold for Tanks,” “Equipment Threshold for Dehydrators,” “Equipment Threshold for Blowdowns,” “Equipment Threshold for Small Combustion Units,” and “Compressor Modes and Threshold.”

Comment Number: EPA-HQ-OAR-2009-0923-0055-3
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

Comment Excerpt Text:
Allow a facility emission factor for standard components at compressor stations.

Response: EPA disagrees that facility level average emission factors should be used for compressor stations. Please refer to the response to EPA-HQ-OAR-2009-0923-1011-19.

Comment Number: EPA-HQ-OAR-2009-0923-1099-15
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Monitoring methods and emissions quantification for: Above ground meter regulators and gate stations 98.232(i)(1)

Section 98.233 (q) requires a leak detection survey of connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines using an optical gas imaging instrument at above ground meter regulators and gate stations. The leak detection survey as proposed is time consuming and expensive. For a detail of issues on leak surveys please see above comment #2 under General Comments on Subpart W. Our company does not have an inventory of all eight components listed in 98.232(i) (1). We would have to visit every meter and regulator to create a component list. To eliminate the burden of the leak survey NMGC suggests applying facility-level emission factors for above ground meters similar to what EPA is proposing for below ground meter regulators. This will eliminate the need to visit hundreds or thousands of meter regulators and perform leak surveys with scarce and expensive infrared cameras. In order to be able to track emission reductions there should be way to adjust the emission factor of a facility due to good maintenance practices and/or replacement of known high emitters with newer equipment.

Response: The commenter has misinterpreted the proposed rule. EPA disagrees that leak detection is required at all meter and regulator stations. Please see the response to EPA-HQ-OAR-2009-0923-1065-4. EPA did not include facility level average emission factors because it does not provide sufficient activity data to inform future policy. Please refer to EPA-HQ-OAR-2009-0923-1011-19.

Comment Number: EPA-HQ-OAR-2009-0923-1152-12
Organization: Consumer Energy Company
Commenter: Amy Kapuga

Comment Excerpt Text:
Reduce Number of Components Requiring Leak Surveys

As we contend elsewhere in these comments, EPA should either allow the use of facility level emission factors or reduce the number of components requiring leak surveys. This will help reduce compliance burdens and costs for underground natural gas storage facilities.

Response: EPA disagrees and did not include facility level average emission factors because it does not provide sufficient activity data to inform future policy. Please refer to EPA-HQ-OAR-2009-0923-1011-19.

Comment Number: EPA-HQ-OAR-2009-0923-1011-46
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(q)(2) Leak detection and leaker emission factors for Onshore natural gas processing facilities.

Currently, Section 98.233(q) requires surveying centrifugal compressor dry seals (for units operated at processing facilities) with an IR camera. Given the fact that dry seals are designed to emit in small amounts under normal operating conditions, it seems more reasonable to apply a population count and population emission factor to this component rather than require leak detection. Therefore, El Paso recommends that requirements for dry seal components fall under Section 98.233(r).

Response: EPA does not agree that dry seal emissions should fall entirely under equipment leaks in Section 98.233(r) of today's final rule. Dry seals may emit gas from two point sources: at the seal face and at vents (where present). The seal face emission can be very small, depending on the presence of an atmospheric pressure vent between tandem dry seals. EPA does not have sufficient data to create an emission factor for dry seal emissions at the seal face, so while a "leak survey" with infrared camera may detect emissions from the dry seal face, there is not a factor to quantify such leakage in Section 98.233(r), and so, this emission will not be reported. However, all vents must be surveyed, measured, and reported, including a dry seal vents. The direct measurement of emissions vented from the dry seal contributes to the emission factors that reporters must use to calculate emissions from various compressor modes. For more information please see "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023). EPA deems this data quality is required to adequately inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-1011-47
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
XVIII. Section 98.233(q)(3) Leak detection and leaker emission factors for Onshore natural gas transmission compression facilities

Table W-3 referenced under Section 98.233(q)(3) does not include a centrifugal compressor component leaker factor for dry seals. Given this component was also excluded from the transmission segment emission source list under Section 98.232(e) it is El Paso's interpretation that the transmission segment does not have any monitoring requirements for centrifugal compressor dry seals. El Paso requests confirmation of this interpretation.

If it was the EPA's original intent for this component to be included in the rule, El Paso recommends the monitoring requirements be similar to those prescribed for processing facilities, and that a population emission factor be added to Table W-3 for dry seals on centrifugal compressor units operated at transmission compression facilities.

Response: EPA disagrees with the comments on transmission centrifugal compressors. In today's final rule, measurement of vented emissions from a centrifugal compressor dry seal vent pipe is required. EPA also disagrees with the use of a population emission factor to quantify emissions from a dry seal compressor. Please see response to comment EPA-HQ-OAR-2009-0923-1011-46.

Comment Number: EPA-HQ-OAR-2009-0923-0847-12
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Table W-2: It appears that the emission rate per facility is the same for offshore and onshore petroleum and gas production. Since different emission inventories were done for the onshore and offshore emissions how can the average facility rate be the same? Please explain.

Response: EPA is unclear where the commenter observed that the emission rate per facility is the same for offshore and onshore petroleum because Table W-2 in the preamble of the proposed rule does not state as such. However, EPA's analysis concluded that the emission rate per facility is not the same for offshore and onshore production facilities. Please refer to the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027).

Comment Number: EPA-HQ-OAR-2009-0923-0955-3
Organization: American Public Gas Association (APGA)
Commenter: Bert Kalisch

Comment Excerpt Text:
The Final Rule should clarify the count for mains in Table W-7.

As noted above EPA's method would presume that all mains, services and below ground M and R stations are leaking, therefore the emission factors for these components would be multiplied by the total number of services, the total number of below ground M&R stations and, APGA assumes, the total miles of mains. Our uncertainty about the count for mains arises because of footnote 2 to Table W-7 in the Proposed Rule which states that the count for mains would be units of scf/hour/service. Number of services does not apply when considering mains. APGA believes that this is an error and that miles of main is what EPA intended to be used as the unit of count. If this is correct, APGA asks that footnote 2 of Table W-7 be changed in the final rule to reflect units of scf/hour/mile of main. If some other factor is to be used in the count for mains it should be listed.

Response: EPA agrees with the commenter's suggested correction to Table W-7 in the proposed rule, and today's final rule text clarifies. The unit for distribution mains has been changed to standard cubic feet per hour per mile of distribution main (scf/hour/mile).

Comment Number: EPA-HQ-OAR-2009-0923-1156-19
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
a. Page 18650, Table W-7 of subpart W – Default Methane Emission Factors for Distribution: The footnotes and one heading of this table appear to contain errors and Laclede suggests they should be revised as follows:

Population Emission Factor – Distribution Services, Gas Service3

2 Emission Factor is in units of "scf/hr/mile."

3 Emission Factor is in units of "scf/hr/service."

Response: EPA agrees with the suggested unit change. Please see response to comment EPA-HQ-OAR-2009-0923-0955-3 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1011-59
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Development of Emission Factors

To develop emission factors, each key compressor component (blow down valve vent, rod packing vent, and unit isolation valve pair) would be measured in the operating condition found at the time of the measurement. Time dependant population emission factors would be calculated for the mode in which each component was not surveyed, by averaging the leakage found in each component category over the total number of components surveyed in that year. In addition to the average leak rate (which is the population emission factor), the standard deviation, and the minimum and maximum observed leak rates should be reported for each factor per component category.

The following are the suggested categories for emission factors and are summarized in Table 4:

1) Blow Down Valve Vent (combine "Operating" and "Standby Pressurized" modes)
2) Pressure Relief Valve Vent (combine "Operating" and "Standby Pressurized" modes)
3) Rod Packing Seal Vent(s) on Reciprocating Compressors
    a. "Operating" Mode
    b. "Standby Pressurized" Mode
4) Unit Isolation Valve Pairs – "Not Operating" mode only

Table 4: Summary of Emission Factor Categories for Compressor Units

Component	Operating Mode		
	"Operating"	"Standby Pressurized"	"Not Operating—Depressurized"
Blow Down Valve	Use measurements in either mode to develop combined factor		Not Applicable
Pressure Relief Valves	Use measurements in either mode to develop combined factor		Not Applicable
Rod Packing Seals	Individual Factor	Individual Factor	Not Applicable
Unit Isolation Valve Pairs	Not Applicable	Not Applicable	Individual Factor

Although emission factors could be calculated by grouping data by units, facilities, operating companies, or industry, El Paso recommends grouping data at the operating company level. Grouping data by facility would most likely result in too few data points to be statistically valid, while grouping data industry wide would increase the uncertainty due to wider differences in equipment and operating practices.

Response: EPA agrees with the commenter's suggested method to develop emission factors for different operational modes. Please see response to comment EPA-HQ-OAR-2009-0923-1099-18.

Comment Number: EPA-HQ-OAR-2009-0923-1014-9
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
Fugitive Emissions Sources

Finally, Subpart W requires all covered facilities to perform comprehensive emissions surveys of their entire population of fugitive emissions on an annual basis. Should a leak be detected during this survey, the current calculation methodologies specified in the proposal require operators to assume that these fugitive emissions occur for the entire 365 days in the year. 75 Fed. Reg. at 18623. Those facilities required to estimate fugitive emissions based on population count (e.g., onshore production facilities) generally must make similar assumptions (i.e., that the emissions occurred for the total time that the specific source associated with the fugitive emissions was operating). See 40 C.F.R. § 98.233(r), 75 Fed. Reg. at 18643. Because this is not the case with regard to most fugitive emissions at most operations, these assumptions will result in a significant overestimation of actual emissions that will artificially inflate the inventory. Indeed, as USEPA acknowledges in the Preamble for Subpart W, "the petroleum and natural gas industry is already implementing voluntary fugitive emissions and repair programs" for detected fugitive emissions that will result in correction of leaks. *Id*. at 18623. Nevertheless, IOGA-WV shares USEPA's view that requiring more frequent emissions surveys would be both unduly burdensome and impractical in light of the marginal levels of emissions that would be captured in the inventory in light of the leak reductions and repairs that are undertaken pursuant to these programs. If anything, IOGA-WV believes that the burdens associated with undertaking a comprehensive annual emissions survey of these sources outweigh the benefits of including these comparatively de minimis emissions in the inventory.

Response: EPA disagrees that equipment leaks are a small portion of emissions from the petroleum and natural gas industry. Equipment leaks are a substantial percentage of emissions from upstream production; EPA conducted detailed analysis in order to determine sources to report in each segment of the industry. EPA does not agree that the burden associated with leak detection is not justified by the benefits. Please see Section III.E of the preamble to today's final rule for a description of the benefits of the rule. EPA recognizes the commenter's concern that assuming a leak duration of 365 days may overestimate emissions. Conversely, there will be leaks that start after a leak survey is conducted and therefore an underestimation may occur as well. Regardless, in today's final rule, EPA allows reporters the option to perform subsequent facility-wide leak detection surveys and to adjust their emissions to account for components that are subsequently found to be leaking or not leaking, respectively. EPA emphasizes that adjustment of emissions is not allowed based on repair records alone. Reporters must assume that a leaking component has been leaking starting from the beginning of the calendar year. In addition, if only one leak detection survey is conducted during the calendar year, the reporter must assume that the duration of the leak is 365 days unless the leak is fixed and a subsequent official leak detection survey is conducted for an entire facility proving that the leak and others were repaired. A goal with leak detection is to get a facility wide snapshot of equipment leak emissions. If a reporter finds certain components leaking during a specific survey they are usually not addressed immediately. During the time leaks are being addressed, other leaks will appear which only subsequent facility wide leak detection surveys will ascertain.

Comment Number: EPA-HQ-OAR-2009-0923-1015-37
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
General Comments – Use of Direct Measurement

On page 18611 of the preamble, the EPA states, "In this supplemental proposal, EPA is requiring the use of direct measurement of emissions for only the most significant emissions sources where other options are not available, and proposing the use of engineering estimates, emission modeling software, and leak detection and publicly available emission factors for most other vented and fugitive sources." We disagree that the EPA is requiring use of direct measurement of emissions "for only the most significant emissions sources where other options are not available." Direct measurement is required for transmission tanks, wet seal degassing, reciprocating rod packing venting, flare stacks. Requiring direct measurement of transmission tanks, wet seal degassing and reciprocating rod packing venting will require field personnel to visit each site to determine which sources must be reported, and to measure each of those sources. Companies sending field personnel to even a portion of these sites will result in emissions from vehicles, wear and tear on equipment, and valuable time lost by staff in the field - none of which appears to have been taken into consideration when calculating the cost of implementing this rule.

PAW requests that EPA reconsider the use of direct measurement for these sources after one year. If these sources are less than 5% (in alignment with The Climate Registry's de minimus emissions) of the total GHG emissions after the first reporting year, PAW recommends that EPA propose emission factors and assumptions as an alternative to direct measurement.

Response: EPA disagrees that direct measurement of emissions is required at all transmission tanks. EPA does not require reporters to schedule new trips to conduct direct measurement of emissions. EPA disagrees with the commenter that emissions from transmission tanks, wet seal degassing and reciprocating rod packing are de minimis in nature. Please see the response to EPA-HQ-OAR-2009-0923-1060-12 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1018-43
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
With respect to the following statement in 98.233(r)(2): "In cases where the stream is almost all CO_2, the emissions factors in Table W-1 shall be assumed to be for CO_2 rather than natural gas." CAPP noticed that the emission factors in Table W-1 do not appear to be referenced to natural gas and contend that it would be acceptable to simply use the factors (which were likely derived from total hydrocarbon emission measurements) and speciate the resulting emission estimate using the appropriate CO_2 and methane content of the emitted stream. CAPP believes this method would eliminate the uncertainty of the text in 98.233(r)(2).

Response: EPA agrees that the emission factors provided in Table W-1 of the proposed rule are for whole gas. Today's final rule has been revised in 98.233 (r) (2) to require EOR operations to use the reporter's actual gas composition.

Comment Number: EPA-HQ-OAR-2009-0923-1018-56
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
Table W-2

CAPP was unable to determine why two sets of emission factors are necessary to account for equipment upstream of a de-methanizer and downstream of a de-methanizer. Fundamentally, there is nothing different in the equipment and how it is operated other than the composition of the gas and this is accounted for in speciating the total estimated emissions in equation W-18.

CAPP is requesting clarification on whether or not the data support the division of emission factors into these two categories, and if the presented emission factors actually taken from two different populations.

Response: EPA agrees and in today's final rule the use of separate emission factors for components before and after the de-methanizer has been eliminated. EPA has combined these and developed a single emission factor. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Revisions to Processing Leaker Emission Factors in Rule Table W-2."

Comment Number: EPA-HQ-OAR-2009-0923-1031-18
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
Provide streamlined emissions estimating methods for upstream production sites with limited GHG emissions. For these sites, the API Compendium provides a reliable, accurate, and streamlined method of estimating emissions. Upstream production sites with CO_2e emissions at or below 3,000 tpy based on the API Compendium would report those emissions as calculated.

Require the largest-emitting upstream production sites to employ more rigorous emissions estimating methods. Upstream production sites with CO_2e emissions above 3,000 tpy based on the API Compendium would use the methods proposed by EPA (as amended according to the additional comments provided below).

Response: EPA disagrees with the comment to allow reporters to choose methods from the API Compendium to determine emissions from onshore production that are not specified in subpart W. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). EPA's criteria for including emission sources under onshore production segment for reporting are outlined in the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027). In addition, EPA set equipment thresholds for onshore production tanks, dehydrators, and blowdown vents to focus the rigorous methodologies on the largest contributors to that particular source. For further information please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Equipment Threshold for Tanks," "Equipment Threshold for Dehydrators," "Equipment Threshold for Blowdowns," "Equipment Threshold for Small Combustion Units" and "Compressor Modes and Threshold."

Comment Number: EPA-HQ-OAR-2009-0923-1004-6
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
The agency can streamline the number of sources that must be monitored at individual facilities

and emphasize engineering estimation approaches over direct measurement.

Response: EPA disagrees with this comment. Please see the response to EPA-HQ-OAR-2009-0923-1031-18.

Comment Number: EPA-HQ-OAR-2009-0923-1202-10
Organization: Enterprise Products
Commenter: Rodney Sartor

Comment Excerpt Text:
The cost and burden of collecting direct measurement data seems to far outweigh any potential gains in data accuracy. Overall, direct measurement methods should be removed and replaced by engineering estimates using appropriate emissions factors, such as those found in the API Compendium or similar sources.

Response: EPA disagrees with this comment. Please see the response to EPA-HQ-OAR-2009-0923-1031-18.

Comment Number: EPA-HQ-OAR-2009-0923-1151-9
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Quality of Measurement Guidance

API supports EPA's selection of a combination of direct measurement, engineering estimation, and emission factors in the re-proposed Subpart W. We believe this mix of approaches will meet EPA's stated intent to "achieve the most cost effective coverage of emissions" (EIA 1.3.2.1; pg. 1-11) and to "collect a reasonable estimate of GHG emissions data that can be used to inform future policy decisions" (EIA 2.3 pg. 2-6) while addressing the problems with the methodologies originally proposed in Subpart W. However, we have presented alternative methods to reduce the cost and burden of the rule while still maintaining complete and accurate data. The methods are detailed in a Section VII of this document.

In addition, API recommends moving the emission factors provided in Tables W-1 through W-8 to a separate document rather than including them in the regulation (API provides additional comments on the specific emission factors in Section IV, response to item W15, and Section VIII of this document). It may not be effective or efficient for EPA to provide emission factors in the regulatory text. Citing the factors in the regulatory text restricts the flexibility to use new emission factors as improvements become available and EPA resources will be required to maintain and update the information. EPA and the oil and natural gas industry associations are conducting measurement programs to improve emission factors. The rule may spur additional activities. As a result, the rule should provide a mechanism for companies to use updated emission factors as they become available.

API requests:

- Flexibility should be afforded to reporters to use either direct measurements or engineering analysis for all sources that require reporting under Subpart W.
- Flexibility should be afforded to reporters to use updated emission factors as they become available. EPA should provide the emission factors in a separate document that is more readily updated and maintained.
- EPA should further improve the methodologies and structure of the rule to meet EPA's stated intent of balancing requirements and burden against emission data needs.

Response: EPA disagrees with the comment to allow reporters the option to choose to update their emission factors. EPA disagrees with the comment on how to update emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1299-5. EPA disagrees with the commenter's suggestion to allow reporters the option for all sources to choose methods not prescribed in the rule. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). EPA selected the monitoring methodologies that would minimize burden on industry while maintaining the necessary quality and uniformity of data to inform policy. Please see the response to EPA-HQ-OAR-2009-0923-1031-18.

Comment Number: EPA-HQ-OAR-2009-0923-1305-11
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Emission Quantification Methodologies

BP supports EPA's selection of a combination of direct measurement, engineering estimation, and emission factors in the re-proposed Subpart W. We believe this mix of approaches will meet EPA's stated intent to "achieve the most cost effective coverage of emissions" (EIA at 1.3.2.1; pg. 1-11) and to "collect a reasonable estimate of GHG emissions data that can be used to inform future policy decisions" (EIA at 2.3 pg. 2-6) while addressing the problems with the methodologies originally proposed in Subpart W. However, given the significant burden which we have estimated, we have included proposals to further reduce the cost and burden of the rule while still maintaining complete and accurate data which are detailed later in this document.

BP recommends moving the emission factors provided in Tables W-1 through W-8 to a separate document which the rule refers to rather than including them in the regulation itself. This would enable more efficient updating of these factors as new emission factors improvements become available. EPA and the oil and natural gas industry associations are conducting several studies aimed at improving emission factors.

Requests:

- Flexibility should be afforded to reporters to use either direct measurements or engineering analysis for all sources that require reporting under Subpart W.

- Flexibility should be afforded to reporters to use updated emission factors as they become available. EPA should provide the emission factors in a separate document that is more readily updated and maintained.
- EPA should take all opportunities to further improve the methodologies and structure of the rule to meet EPA's stated intent while balancing requirements and burden against emission data needs.

Response: EPA disagrees with this comment. Please see the response to EPA-HQ-OAR-2009-0923-1151-9.

Comment Number: EPA-HQ-OAR-2009-0923-1031-9
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
The rule should not require an actual fugitive component count. Due to the vast expansion of the scope (i.e., inclusion of upstream facilities), this proposal has drastically increased the burden of reporting and accounting for all the required source types. Anadarko is particularly concerned with the requirement to count all the fugitive components on every well site and small production facility that we operate. This requirement is very significant in terms of effort and cost. Moreover, an actual count is not needed to develop a reasonable estimate of fugitive emissions from leaking components. The total emissions from such sources is a tiny fraction of total GHG emissions from this sector, so requiring an actual count results in an estimate that is unnecessarily precise. Accordingly, we request that EPA allow operators to generate an engineering estimate of the average component count for well sites and other related upstream equipment.

Response: EPA agrees with the commenter's concern that physically counting each component in onshore natural gas and oil production operations would be overly burdensome. Please see the response to EPA-HQ-OAR-2009-0923-1151-126.

Comment Number: EPA-HQ-OAR-2009-0923-1040-7
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The rule should not require an actual fugitive component count. Due to the vast expansion of the scope (i.e., inclusion of upstream facilities), this proposal has drastically increased the burden of reporting and accounting for all the required source types, AXPC is particularly concerned with the requirement to count all the fugitive components on every well site and small production facility that we operate. This requirement is very significant in terms of effort and cost. Moreover, an actual count is not needed to develop a reasonable estimate of fugitive emissions from leaking components. The total emissions from such sources is a tiny fraction of total GHG emissions from this sector, so requiring an actual count results in an estimate that is unnecessarily precise. Accordingly, we request that EPA allow operators to generate an

engineering estimate of the average component count for well sites and other related upstream equipment.

Response: EPA agrees with the commenter that physically counting components in onshore natural gas and oil production operations would be unduly burdensome. Please see the response to EPA-HQ-OAR-2009-0923-1151-126.

Comment Number: EPA-HQ-OAR-2009-0923-1039-22
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
B. Recordkeeping and Reporting Requirements Should Be Limited to Data that Are Reasonably Accessible and Pertinent to the Regulatory Objective

§98.236 identifies reporting requirements associated with the sources listed in §98.233. Some requirements are infeasible. In other cases, INGAA recommends that EPA not require data collection based on the possibility that the data could be useful in the future, such as to formulate new EFs or emission intensity factors.

INGAA comments follow for §98.236 where INGAA recommends deleting the item from the list of reported parameters or including the parameter in the GHG Monitoring Plan required under §98.3(g)(5) rather than including the information in the annual report.

•§98.236(c)(9) – Blowdown venting: Item (i) should not be required or could be reported in the GHG Monitoring Plan. Item (ii) is not applicable as the compressor is driven equipment and not the driver. Item (iii) should be clarified to indicate the volume associated with particular systems that could be released through the vent, and this parameter is more appropriately documented in the GHG Monitoring Plan.

•§98.236(c)(11) – Tank emissions identified with optical gas imaging instrument: The first five parameters – i.e., (i) through (v) are input parameters associated with E&P Tanks software emission calculations (i.e., see item (c)(10) list of parameters) and should be deleted from the Rule. These parameters are not relevant when performing tank vent measurements from malfunctioning scrubber dump valves.

•§98.236(c)(17) – Centrifugal compressor wet seals: As noted in Comment IV.C, compressor throughput is not readily available and reporting this parameter would add significant burden. EPA has not identified why these data are needed. It is imperative that item (iii) is deleted.

• §98.236(c)(18) – Reciprocating compressor rod packing venting: As noted in the Comment V.D and the previous bullet, compressor throughput is not readily available and reporting this parameter would add significant burden. It is imperative that item (i) is deleted. In addition, item (ii) should be revised and reconciled with revisions recommended by INGAA above that address multi-mode test requirements. Furthermore, items (iii) through (v) should be deleted from this section and included in the GHG Monitoring Plan rather than including the information in the annual report.

• §98.236(c)(19) – Fugitive emission sources using EFs: Item (i) should be clarified so that appropriate “counts” are reported and unnecessary documentation is avoided. For example, as written, item (i) could be interpreted to mean that all components must be counted and reported even if the EF is “leaker” based. Item (i) could be clarified by adding (i)(A) and (i)(B) as follows:

“(A) Component count for each fugitive emissions source where component population is reported for population emission factors, or

(B) Component count for each fugitive emissions source where the number of leaking components are reported for leaker emission factors.”

If EPA intended to require total component counts for leak surveys that use leaker EFs, INGAA recommends deleting that requirement. Considerable burden is added to complete a total component count, and transmission sector personnel with expertise to complete detailed facility-wide component counts are very limited.

• §98.236(d): The requirement for “minimum, maximum and average throughput for each operation” in the natural gas transmission and storage segments is not clear. This requirement should be deleted or these terms should be specifically defined. If this is intended to require gas throughput values for compressor stations, INGAA recommends that the requirement be deleted because such information is not readily available for many facilities. The implications from deleting this requirement is not evident due to the lack of clarity in the requirement.

• §98.236(f): To avoid confusion and for consistency with requirements elsewhere in Subpart W, this section should specifically identify the affected portable equipment based on the following revision:

“(f) Report emissions separately for production wellhead portable equipment…”.

Response: EPA reviewed the commenter’s concerns about the data reporting requirements in 98.236 for blowdown vent stacks and has revised the requirements in today’s final rule. The commenter has listed several reporting requirements for compressor blowdown vent stacks which have been revised and are not included in today’s final rule.

With regard to transmission tank emissions identified with optical gas imaging instrument, EPA agrees that not all of the reporting parameters listed in the proposed rule were necessary to determine emissions related to malfunctioning scrubber dump valves. Today’s final rule no longer requires the reporting of scrubber temperature and pressure, sales oil API gravity, tank capacity, tank throughput, or tank control measures.

With regard to centrifugal compressor data reporting requirements, EPA disagrees that average annual throughput should be eliminated. EPA requires the compressor throughput for analysis of the activity data and the resultant GHG emissions reports, as combustion CO2 will be proportional to compressor throughput. EPA removed the “minimum, maximum and average throughput for each operation” in today’s final rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-36 for further details.

With regard to multiple mode compressor testing, it was not EPA’s intent to require that reporters shutdown compressors annually for the purposes of monitoring. Today’s final rule clarifies that measurements are to be made in the “as found” mode, and that shutdown, depressurized mode must be measured at least once every three years for each compressor. The reporting requirements have been reconciled with this clarification. For more information, please see the response to EPA-HQ-OAR-2009-0923-1099-18. Finally, EPA agrees that whether or not each rod packing case is connected to an open ended line, the type of device used for measurement, and the locations from where emissions were detected are not necessary data for informing future policy. Today’s final rule no longer requires that these data elements be reported.

With regard to component counts corresponding to equipment leaks, EPA clarified the reporting requirements after considering comments. In today’s final rule, the number of components found leaking during a leak detection survey is reported. However a complete component count is required for components that use a population emission factor. Today’s final rule has eliminated the ambiguity of data reporting from these two sources.

With regard to data reporting requirements for portable combustion equipment, EPA agrees that clarification was necessary such that portable combustion equipment reporting is for onshore production equipment only. However, EPA disagrees that the data reporting requirements section is the proper location for this clarification. EPA has clarified the combustion equipment that needs to report under Section 98.232 of today’s final rule, which lists all the emissions sources that must report in each segment of the petroleum and natural gas industry. Today’s final rule defines that monitoring and reporting of combustion emissions from stationary and portable equipment are required for reporting for onshore production and natural gas distribution.

Comment Number: EPA-HQ-OAR-2009-0923-1042-21
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
§98.233(q) Leak Detection and Leaker Emission Factors, and §98.233(r) Population Count and Emission Factors:

ConocoPhillips Comment:

a.) §98.233(q) allows the use of optical imaging to find leaks and then to apply emission factors to estimate the emissions from the components found leaking. We request that this method be extended as an alternative to onshore natural gas and petroleum facilities which are proposed to be covered under §98.233(r). As API has ably pointed out, compliance with §98.233(r) could prove very cumbersome and burdensome due to the difficulty and man-hours that will be required for accurate equipment counts – particularly for facilities as large as our North Slope operations. So we request the option of using the method of §98.233(q) so we may avail ourselves of it if it proves more efficient and feasible.

b.) We believe that the proposed rule contains an error. Both §§98.233(q) & (r) have the LNG Storage (98.232(g)(3)) and the LNG Import and Export Equipment (98.232(h)(4)) categories referenced. We don't believe that EPA intended to subject fugitive leak components to both quantification methods so we request that EPA correct this.

c.) As an alternative to requiring the manual counting of facility components for fugitive leaks, we request that EPA allow the use of facility component estimations as presented in the API Compendium.

Response: EPA disagrees that it should allow leak detection in lieu of population count. However, EPA has revised today's final rule for onshore production to allow equipment level counts instead of component level counts. EPA deems the use of population emission factors to be the least burdensome method for reporting emissions. Please see the Section II.E of the preamble to today's final rule. In addition, EPA intends to maintain the use of population emission factors so that consistent data is reported for onshore production.
EPA disagrees with the comment on duplication of emissions sources under Sections 98.233(q) and 98.233(r) of today's final rule. Please see response to comment EPA-HQ-OAR-2009-0923-1061-5.

EPA disagrees that facility level average emission factors should be used. Please refer to the response to EPA-HQ-OAR-2009-0923-1011-19.

Comment Number: EPA-HQ-OAR-2009-0923-1061-16
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
API factors should be allowed for calculation of emissions from centrifugal compressor wet seal degassing vents. Section 98.233 (o) would prescribe methods for calculating emissions from centrifugal compressor wet seal degassing vents. EPA should modify the proposed rule so that API factors may be used as an alternative if the operator so chooses. As indicated above, use of API factors is standard in the industry and their use should be available as an alternative to parties complying with Subpart W.

Response: EPA has reviewed this comment and disagrees. New data and increased knowledge of industry operations and practices have highlighted the fact that centrifugal wet seal degassing venting emissions estimates based on the factors used in API Compendium are outdated and potentially understated. EPA determined that direct measurement of centrifugal wet seal degassing venting is required to maintain the necessary quality of data to inform policy. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1082-14
Organization: MidAmerican Energy Holdings Company
Commenter:

<u>Comment Excerpt Text:</u>
EPA requests comment on the use of emission factors and ways in which these shortcomings may be overcome. (page 69)

The EPA, under its Natural Gas STAR program, as well as regulated companies has conducted direct measurements of methane leakage. With this data, most companies are aware of the components that require direct measurement as well as those that can utilize default values. It is appropriate to use emission factors for small components; however it is crucial to give companies the ability to conduct engineering analysis so more relevant emission factors for specific applications can be ascertained. It is important to give companies flexibility when using emission factors so they can produce the most accurate result.

Response: EPA disagrees with the commenter's suggestion to allow reporters the flexibility to develop their own emission factor through engineering analysis. EPA selected the monitoring methodologies that would minimize burden on industry while maintaining the necessary quality and uniformity of data to inform policy. EPA may consider refinements in emissions factors and, at an appropriate future date, update emissions factors as necessary. For additional information on emissions factor updates, please see EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-1027-11
Organization: Offshore Operators Committee
Commenter: Allen Verret

<u>Comment Excerpt Text:</u>
98.233(n)(7): Calculate N_2O emissions using the emission factors for Gas Flares listed in Table W-8 of this subpart.

OOC Comment: No equation is given to calculate N_2O emissions from flares, and Table W-8 references an emissions factor in metric tons/MMSCF gas production or receipts. The emission factor should apply to flared gas volume as CO_2 and CH_4 emissions do, rather than total gas production or receipts.

Response: In today's final rule, EPA eliminated the use of flare emission factors based on receipts. These emission factors are from the API compendium and are broad factors meant to be applied to national level data. EPA deemed this level of reporting to be inaccurate for the purposes of informing future policy. In today's final rule, flare N_2O emissions are calculated using an equation based on the volume of fuel that is combusted. This method, which can be applied to specific combustion sources, significantly improves the quality of data gathered while minimizing the burden on reporters.

Comment Number: EPA-HQ-OAR-2009-0923-1151-72
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
W11. (Preamble p. 69)
EPA considered several options for estimating emissions from fugitive emissions sources. One option considered was to use a population count of each fugitive emissions source (e.g. source types such as valves, connectors, etc.) and multiply it by a population emissions factor. EPA requests comment on the use of emission factors and ways in which these shortcomings may be overcome.

In order [to] minimize reporting burden, API members recommend that EPA allow the use of engineering estimates to determine fugitive component counts. This would enable reporters to apply average counts of fugitive components for typical equipment within a Sub-basin entity, such as those provided in Section C.1.5 of the 2009 API Compendium (note the API Compendium data are from Canada) or to develop “typical” component populations for their operations, such as on a per site or per equipment basis. API presents an alternative method for quantifying component counts in Section VII.N of this document.

Response: EPA disagrees with allowing engineering estimation as a methodology to determine the population count of components. EPA revised today’s final rule for equipment leaks in onshore production to allow the option of major equipment level counts (wellheads, separators, meters/piping, compressors, inline heaters, dehydrators) and apply default average component counts per primary equipment. Please see Section II.E of the preamble to today’s final rule. However, in the other segments of the petroleum and natural gas industry, EPA requires reporters to create an inventory of components by physically counting. This level of data quality is necessary in these other segments of the industry to inform future policy, and incurs an acceptable cost burden.

Comment Number: EPA-HQ-OAR-2009-0923-1305-41
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Fugitive Emissions Estimation

EPA considered several options for estimating emissions from fugitive emissions sources. One option considered was to use a population count of each fugitive emissions source (e.g. source types such as valves, connectors, etc.) and multiply it by a population emissions factor. EPA requests comment on the use of emission factors and ways in which these shortcomings may be overcome.

In order to quantify emissions without resulting in additional reporting burden, BP recommends that EPA allow the use of engineering estimates to determine fugitive component counts. This would enable reporters to apply average counts of fugitive components for typical equipment, such as those provided in Section C.1.5 of the 2009 API Compendium (note the Compendium data are from Canada) or to develop "typical" component populations for their operations, such as on a per site or per equipment basis.

Response: EPA disagrees with this comment. Please see the response to comment EPA-HQ-OAR-2009-0923-1151-72.

Comment Number: EPA-HQ-OAR-2009-0923-1151-79
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Paragraph 98.232 (i)(1) Natural Gas Distribution. Indicates that fugitive emissions from "other meters" are to be reported. However, Table W-7 does not provide an emission factor for this source.

Response: In today's final rule, EPA has removed "other meters" as an emission source in natural gas distribution. An emission factor was not provided for this source in the proposed rule, and was accordingly removed from 98.232 (i) (1) as suggested.

Comment Number: EPA-HQ-OAR-2009-0923-1156-10
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
With this said, Laclede is once again compelled to state that applying standardized emission factors to these system components, as with gas mains and service lines, will not yield accurate fugitive emissions; it will only add unnecessary incremental cost to the utility and its ratepayers. Moreover, system technicians visit these stations regularly to perform mandatory safety inspections and prescribed maintenance, and the equipment at these stations is rarely found to be leaking. In the rare instances when leaks are detected, they are promptly corrected in compliance with the pipeline safety regulations.

Response: EPA disagrees that the emission factors in the rule are inaccurate. EPA determined that distribution population emission factors would result in reduced burden on industry while maintaining the necessary quality of data to inform policy. Please see the Technical Support Document (TSD) for today's final rule found in docket (EPA-HQ-OAR-2009-0923). EPA disagrees that the leak inspection requirements of the Department of Transportation meet the requirements of subpart W. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923) "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements."

Comment Number: EPA-HQ-OAR-2009-0923-1156-6
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
Limitations / misapplication of emission factors:

Fugitive emissions calculated using emission factors should not be the basis for requiring an LDC distribution system to report under subpart W.

EPA's standard emission factors, multiplied by the number of system components covered by the rule, will not result in a complete or accurate accounting of each LDC's gas losses. There are too many other variables involved, such as gas line purges and blow-downs during construction and repairs, other regular maintenance activities, and gas lost due to third-party dig-ins. Although these are routine occurrences that LDCs are accustomed to managing and reporting them to authorities, as appropriate, it is not practical to keep track of every such occurrence and attempt to quantify the volume of gas associated with every release. For instance, not only would it be cost prohibitive, but also highly unsafe to attempt to measure gas leakage from a broken line while in the process of exposing it for the purpose of making repairs. In large, highly integrated, looped distribution systems, it is not possible to accurately isolate the volume of such leakage apart from other recognized categories of gas losses. Be assured, however, that gas releases of every type are minimized due to the economic and safety aspects referenced above.

Also, the natural gas emission factors in use today, although dated, were developed to represent a macro, nationwide, cross-section of industry applications. EPA actually stands to lose definition by requiring operators to apply these factors on a micro, system by system basis because there can be much variability in system construction and maintenance practices among system operators, as well as marked differences in operating parameters.

Furthermore, because EPA is likely aware, the emission factors commonly in use today for pipes do not differentiate between pipe diameters and the wide spectrum of internal gas line system pressures, although they do take pipe material into account. EPA should recognize that calculating fugitive emissions for a discrete distribution system by means of the published factors would only by coincidence yield an accurate portrayal of that gas system's fugitive emissions, and even then, there are no means by which to verify that the fugitive emissions so calculated are correct.

Response: The commenter has misinterpreted the proposed rule. EPA did not include distribution pipeline blowdowns or dig-ins, these sources did not fall under the 80:20 source selection criteria. Please see the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027). EPA disagrees that all distribution equipment leak emission factors are dated. Please see response to comment EPA-HQ-OAR-2009-0923-1059-9. For further information on the derivation of emission factors used in the distribution sector, please refer to the rulemaking docket (EPA-HQ-OAR-2009-0923) under “Revisions to Processing Leaker Emission Factors in Rule Table W-2” and Appendix L of the TSD (EPA-HQ-OAR-2009-0923-0027).

EPA disagrees with the comment on verification. Please see Section II.N of the preamble to The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98).

Comment Number: EPA-HQ-OAR-2009-0923-1167-22
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source. The large number of onshore oil and gas production emission sources – e.g. about 800,000 wellheads nationwide, over 10,000 wellheads and 6,000 separators and storage tanks for Noble operations alone – preclude the cost-effective collection of required data and samples for each individual emission source. For example, it is estimated that on the order of 20,000 man-hours would be required to survey just the component counts in the Noble inventory, and components are a relatively small emission source (estimated to be about 3% of the total Subpart W inventory in Table 2).

For each emission source, required parameters would be collected from a statistically random sample of the emission sources in a basin. The average emissions determined for the emission source (i.e. emission factor) would then be applied to each emission source in the basin to calculate the total emissions estimate. As data objectives and policy are better defined, a more robust data set will have been reported and serve as the basis for improving the sample size determination and data needs. To provide clarity and compliance assurance, Noble recommends that the maximum number of sources sampled each year in a basin would be 5% of the total or 30, whichever is less. The minimum number of sources sampled each year in a basin would be 5 or the entire population if less than 5.

Response: EPA disagrees with the comment regarding allowing onshore production reporters to conduct their own random sampling to determine emissions, as this would not ensure the data quality necessary to inform policy. Please see the response to EPA-HQ-OAR-2009-0923-1151-126. The commenter provided no details on how a random sample would be chosen, or what parameters would be collected, or how emissions would be calculated. In addition the commenter suggests that EPA needs to better define its objectives before it finalizes data requirements for subpart W. EPA disagrees with this comment, as EPA’s authority to promulgate this final rule is well defined. Please see Sections II.C and II.Q of the preamble to The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98)

Comment Number: EPA-HQ-OAR-2009-0923-1176-1
Organization: Citizens Energy Group
Commenter: Ann W. Mclver

Comment Excerpt Text:

Additional clarification is needed for the types of components listed in the other category referenced in Table W-5 and Table W-6.

Response: EPA disagrees, as the proposed rule has defined the other category in Table W-5 and Table W-6 as any component other than connectors, pumps, or valves, with footnotes within the tables themselves.

Comment Number: EPA-HQ-OAR-2009-0923-1200-7
Organization: The Dow Chemical Company
Commenter: Robert Rouse

Comment Excerpt Text:

Dow Comments that EPA's Proposal for Use of Leaker Emission Factors for Pressure Relief Valves and Compressor Blowdown Valves in Table W-4 Has the Potential to Create Uncertainties for the Regulated Community.

Dow operates an underground storage facility where the vent piping associated with a number of Pressure Relief Devices and Compressor Blowdown valves is combined into a larger piping network with a single vent opening to the atmosphere. If a leak is detected at the outlet of the common discharge piping, it may not be possible to determine which pressure relief valve or blowdown valve is leaking or even if more than one source is leaking in these cases. Thus, Dow comments that EPA's final rule should contain one or both of the following options for this situation where the vent piping is combined together:

- Allow the use of engineering analyses or additional measurements, if possible, to determine which pressure relief valve, blowdown valve, and/or how many pressure relief valves or blowdown valves are leaking or;
- Rely solely on the use of Population Emission Factors for calculating fugitive emissions from pressure relief valves and blowdown valves and not require an annual survey for these sources.

Response: EPA disagrees with the use of an engineering analysis to quantify venting emissions from through-valve leakage. These methods will not accurately quantify venting emissions from a significant source of emissions to adequately inform future policy decisions. However, today's final rule has been revised and EPA is allowing the use of an acoustic leak detection instrument to detect and measure venting emissions from through valve leakage from transmission tanks, and centrifugal and reciprocating compressor venting. EPA disagrees with solely using population emission factors for underground storage facilities. Please see Section II.E of the preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002).

Comment Number: EPA-HQ-OAR-2009-0923-1200-8
Organization: The Dow Chemical Company
Commenter: Robert Rouse

Comment Excerpt Text:
Dow Comments that Regulated Entities Should be Able to Take Credit for Repairing Leaking Equipment.

EPA solicits comment on whether an alternative approach that requires multiple surveys during a year should be required in order to improve the quality of the emission estimate for leaking equipment. Dow comments that EPA's final rule should continue to require a survey on an annual basis, but that regulated entities should be able to take credit for repairing leaking equipment during the year. For example, if a component is found to be leaking methane on July 15th and the regulated entity makes repairs to the component and stops the leak on July 16th, then credit should be taken for the repair. In this example, the emissions would be calculated using the "Leaker" emission factor from the period January 1 - July 15th, and using the Population Emission Factor from July 16th to December 31st. It is our belief that almost all regulated entities will address discovered leaks, thus this type of approach will increase the quality of the emission estimates.

Response: EPA agrees to allow multiple leak detection surveys. Please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1306-13
Organization: DTE Energy
Commenter: Gregory L. Ryan

Comment Excerpt Text:
The first year level of effort to meet the required leak detection and monitoring of the distribution system will be the most burdensome as technicians require training on leak detection methods and the database of sources is established. Under the proposed rule, an annual database of leaking components at above grade M&R stations would need to be developed to calculate GHG emissions utilizing the leaker emission factors in Table W-7. We would likely build on existing databases and drawings to help develop a compliance plan for monitoring leaks and reporting emissions from above grade M&R stations. However, the additional information needs would not likely be met by existing inventories or databases, and significant additional work may be required depending on the number of leaking components. For example, MichCon already maintains a database of components that lists the regulators, meters, pressure relief valves and line heaters at each M&R station as required by the Michigan Public Service Commission. This database contains information on the component manufacturer, model number, and design operating pressures. There are engineering schematics for each station, but these designs will not necessarily include all connectors, and some bypass lines will not be included in the schematics.

Because of the scale of distribution systems and the implementation issues described above, DTE Energy supports delaying the implementation of greenhouse gas reporting for M&R stations for at least a year. In place of leak detection, DTE Energy supports using default emission factors for above grade M&R stations as is allowed for below grade M&R stations.

Response: EPA disagrees with delaying the implementation of today's final rule. Leak detection is not required at all meter and regulator stations, thereby reducing the burden on reporters. Please see the response to EPA-HQ-OAR-2009-0923-1065-4. A leak detection survey can be conducted anytime during the year, which provides additional time for training personnel and developing databases. EPA does not anticipate the need for more time but with sufficient documentation, the reporter may apply for best available monitoring methods so long as the reporter meets very specific circumstances, as outlined in the best available monitoring methods criteria. For further information please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-3522-1
Organization: Heath Consultants
Commenter: Milton W. Heath

<u>Comment Excerpt Text:</u>
Direct Measurement vs. Emission Factors

The EPA's use of emission factors derived from the GRI (Gas Research Institute)/EPA study performed in 1996 do not take into account the variations occurring from new maintenance practices, better sealing materials and an overall bigger concern for the fugitive emissions resulting in lost and unaccounted for gas.

To simply categorize each of the leaking components by emission factor limits the ability to truly quantify those emissions and create an accurate, up to date emissions inventory. Through extensive field work and thousands of accurate leak measurements, it has been proven that the use of the Hi Flow Sampler for direct measurement in all phases of compliance for the EPA's Mandatory Reporting Rule 40 CFR 98 Subpart W will be the most accurate method available today. It is estimated that the use of the Hi Flow Sampler for quantification use will cover approximately 98% of all vented and fugitive emissions encountered during the emissions inventory survey, making this a very effective and accurate device for conducting the surveys. What's more, the Hi Flow Sampler takes into account temperature and pressure at the point of measurement which lends significant credibility to this measurement data thereby reducing error associated with other estimation techniques. The balance of the quantification events may be accomplished using a variety of other means including but not limited to:

1. Calibrated vent bag system
2. Rotameter
3. Anemometer
4. Ultrasonic flow device

The use of the Hi Flow Sampler for the direct measurement (quantification) of vented and fugitive methane emissions has been approved as standardized methodology by both the EPA and the United Nations FCCC (Framework Convention on Climate Change AM0023) for the Kyoto Protocol's Joint Implementation and Clean Development Mechanism programs. This is proven technology that has demonstrated remarkable accuracy as verified in side by side comparative studies with both rotameters and calibrated vent bags.

Based on these facts, it is recommended that the Hi Flow Sampler, as a proven quantification device be utilized to provide the most accurate, up to date data in emissions inventorying. This will provide the best quantified emission inventories for compliance to the new EPA's Mandatory Reporting Rule.

Response: EPA disagrees that it should require reporters to submit measured emissions data with the high volume sampler for all equipment leaks and vented emissions. EPA is allowing the use of the high volume sampler for venting emissions from centrifugal and reciprocating compressors, where direct measurement to quantify emissions is required to adequately inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-9
Organization: American Gas Association
Commenter: Pamela Lacey

<u>Comment Excerpt Text:</u>
Fourth, we are worried that you are trying to go too far down into the weeds at distribution facilities asking for estimated emissions from too long a list of individual components. Our members do not typically keep a comprehensive inventory of the number of components that they have at any given metering and regulator station. For example, one of our companies – I'll get to that in a moment. The proposed rule apparently would require knowing the number of each type of component in order to apply a component-specific emission factor multiplied by the number of components. And if we don't already have that list then we're going to have to go out to each of those stations out at remote locations and make an inventory.

Now, I know that this sounded logical in theory, but in practice, it would be onerous. It would require our gas utility personnel to visit thousands of remote facilities surveying equipment for each station in minute detail just to develop these lists of components. One company for example operates at least 10,000 M&R stations. This will require many hours of work at great expense to go out and do these surveys.

And then for what result? Because in the end all we can do with the old emission factors is to calculate a fictional number that we all know is seriously inaccurate and is likely to vastly overstate and misrepresent the level of actual emissions at distributional facilities.

Response: EPA disagrees with the comment that today's final rule requires creation of an inventory of all components at meter and regulator stations. EPA is requiring leak detection and a count of leaking components only at custody-transfer gate stations, which significantly reduces the burden. Please see the response to EPA-HQ-OAR-2009-0923-1065-4 for further details. EPA disagrees that emissions factors used in today's final rule are inaccurate and misrepresentative. EPA used the best available, public data to develop the emission factors in the natural gas distribution segment. Please see the response to EPA-HQ-OAR-2009-0923-1299-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0053 -2
Organization: Cardinal Engineering, Inc.
Commenter: Kristine D. Baranski

<u>Comment Excerpt Text:</u>
The proposed rule does not provide any simplified method for determining applicability. Similar to the final version of Subpart C - facilities with less than 30 mmBtu/hr aggregate maximum heat rating are not required to report if only potentially subject to Subpart C - there should be a less-costly method for determining applicability than requiring all of the direct monitoring, engineering estimation, component counts, etc. that are required by Subpart W. Please consider providing emission factors that would apply only to applicability determination calculations or other less costly applicability determination method.

Response: EPA intends develop a screening tool to assist in the determination of which entities are required to report under subpart W of 40 CFR part 98. Please see Section II.F of the preamble to today's final rule for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1151-44
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(r) Population count and emission factors. Table W-3 provides the emission factor for onshore natural gas transmission natural gas pneumatic low bleed device venting. Paragraphs Section 98.233(r)(2) through (7) reference Tables W-1 through W-7 for source category emission factors. However, Section 98.233(r)(2) through (7) does not reference Table W-3 for onshore natural gas transmission emission factors. In addition, the sources Section 98.233(f)(5), (g)(3), h(4) are included in both Section 98.233(q) and Section 98.233(r), which is duplicative and the sections have different requirements.

Response: EPA agrees, and has revised today's final rule to remove the reference to pneumatic devices from Section 98.233(r) of today's final rule. EPA disagrees with the comment on duplication of emissions sources under Sections 98.233(q) and 98.233(r) of today's final rule. For further details, please also see the response to EPA-HQ-OAR-2009-0923-1061-5.

Comment Number: EPA-HQ-OAR-2009-0923-0055-11
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

<u>Comment Excerpt Text:</u>
Suggestion 5: Allow leak measurements to be made as an option to determine bleed rates of pneumatic control devices.

Sections 98.233 (a) and (b) require the use of either manufacturer's data for high bleed pneumatics or the application of an emission factor for low bleed pneumatics. However, identifying the model of a particular device may be difficult if name plates are obscured by paint or wear. Additionally, some units may have been modified over time to reduce their bleed rate, but accurate records of these modifications may not be available. As an option, the Hi-Flow sampler or similar device could be used to make a measurement of the bleed rate from pneumatic devices. If companies already have this technology in house or are having it contracted for other measurements at their sites, this could provide a method to obtain data that might otherwise be hard to get.

Response: EPA disagrees that it should allow reporters to submit measured emissions data for pneumatic devices in today's final rule. EPA has revised today's final rule to require population emission factors for pneumatic devices and pumps, to reduce burden. Please see Section II.F of the preamble to today's final rule. In the proposed rule, EPA required reporters to determine the manufacturer model of each device in their facilities, and then estimate emissions based on manufacturer data. However, many potential reporters commented that the cost burden was too high. EPA accepted these comments and revised the rule to population emission factors to reduce compliance burden on industry while maintaining the necessary quality of data to inform policy

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Comment Number: EPA-HQ-OAR-2009-0923-1015-25
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Tracking natural gas bleed rate during normal operation for every high bleed device will be difficult to compile for the thousands of devices. PAW asks the EPA to propose a reasonable high bleed emission factor to use in place of manufacturer's data if manufacturer's data is unavailable. Further, it is unclear what the EPA means by "continuous." If it is a "continuous" bleed device, why is there a time element in the equation? Lastly, it is unclear at what point is the unit considered not in operation and therefore exempt.

Response: EPA agrees, and has revised today's final rule to include population emission factors for pneumatic device venting, which will eliminate the need to determine the device manufacturer model; please see the response to EPA-HQ-OAR-2009-0923-1011-8. In today's final rule, all natural gas pneumatic devices are assumed to be venting during the entire reporting period; please see the response to EPA-HQ-OAR-2009-0923-1039-8. The definitions of continuous and intermittent bleed pneumatic devices are in Section 98.6 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1167-33
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Natural gas driven pneumatic pumps: Noble recommends the use of an emission factor(s) (such

as the emission factor(s) for natural gas driven pneumatic pumps listed in the API Compendium) based on natural gas driven pneumatic pump counts in each reporting area to determine emissions from pneumatic pumps. If EPA does not support the use of the emission factor method, then Noble supports API's suggested alternative methods for natural gas pneumatic pumps.

Response: EPA agrees, and has revised today's final rule to use a GRI emission factor for pneumatic pumps. Please see the response to comment EPA-HQ-OAR-2009-0923-0055 -11.

Comment Number: EPA-HQ-OAR-2009-0923-1206-32
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Natural gas pneumatic low bleed device venting: The sources covered by this section are also covered by Section 98.233(r) for using population count and emission factors. We request that EPA delete this section to avoid double reporting or, alternatively, allow an operator to use an engineering estimate of the count of low bleed pneumatic devices.

Response: EPA agrees and has revised today's final rule. Please see response to comment EPA-HQ-OAR-2009-0923-1151-44.

Comment Number: EPA-HQ-OAR-2009-0923-1206-31
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Natural gas pneumatic high bleed device venting: We request that EPA allow an operator to use an engineering estimate of the count of high bleed pneumatic devices and a typical bleed rate to calculate emissions from this source category on a facility-wide basis rather than per each device.

Response: In regards to engineering estimates of pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. EPA has included population emission factors to reduce the burden of determining the bleed rate of each high-bleed pneumatic device required to report. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1305-17
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Table W-2 is missing a Low Bleed Pneumatic Device emission factor, although this table is referenced for the emission factor in 98.233(b), Equation W-2.

Response: EPA agrees, and in today's final rule, EPA has revised the rule and included a population emission factor for low-bleed pneumatic devices that is applicable to the onshore natural gas processing sector.

Comment Number: EPA-HQ-OAR-2009-0923-1155-12
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

<u>Comment Excerpt Text:</u>
Sampling and Audit Program
The dramatic underestimates of emissions from the oil and gas sector, acknowledged by EPA, demonstrate the critical need to immediately improve the quality of emissions factors used where direct measurement is not required and the importance of providing well-audited emissions data to support quality policy-making. To that end, EPA should commit to a rigorous periodic statistical sampling and audit program, beginning immediately, in order to ensure continuous improvement in the data collected under the MRR. EPA should establish, either as part of this rulemaking or in a separate sample and audit program, a specific plan and detailed timeline for carefully measuring emissions and maximizing the precision and accuracy of its estimation protocols.

Such an audit program should not, in any way, delay establishing reporting requirements for this sector and indeed should build on the data collected under the initial version of the rule. Rather, the goal of such a program should be stepwise improvement using the data gathered from the reporting rule in 2011 as the input for a sampling and audit program aimed at improving the quality of the data reported in subsequent years, perhaps as early as 2012.

Because uncertainties in emissions estimates could result in large-scale data quality issues if they become ingrained, EPA must commit to actively conduct sampling and audit to minimize the known uncertainties in quantifying emissions from this complex and fragmented sector. Because of the fragmented nature of this sector, there will be many factors to consider in constructing a useful audit program. EPA should place a high priority on those sources with the least certain reporting methods (e.g., pneumatic devices and onshore production and processing storage tanks, metering of vent flows from tank emissions) and on those sources where wide variability in emissions has been demonstrated, such as well completions. EPA should consider the use of randomized samples, collected at varying times and locations, from sources with the highest potential emissions and should place an emphasis on the top emitting source types. Guidance on sources to target may be available from California's current efforts to improve their O&G inventory, which is planned for completion this summer.[185] In addition, EPA should work actively with industry and equipment vendors to collect the broadest pool of direct measurement data possible. Another available resource for helping determine the highest priority sources would be the Western Regional Air Partnership's recent screening inventory analysis for the oil

[185] The California Energy Commission has a contract to develop new natural gas system emission factors and the California Air Resources Board has a contract to develop new emission factors for oil fields. The timeline for both inventories is for completion in summer 2010. See Oil and Natural Gas Production, Processing and Storage Public Workshop, CARB, Sacramento, California, December 8, 2009.

and gas exploration and production sector, which was designed to help rank GHG source categories associated with exploration and production operations.[186]

It is possible that some sources are already collecting samples that could be used as part of EPA's auditing program (e.g., in order to meet reporting requirements for ozone nonattainment area plans). In these cases, EPA could simply designate a certain percentage of samples for independent analysis and review. For those industry sources where direct measurement will not be required, alternative requirements for independent auditing of emissions estimate methods should be included as part of the final rule for those sources.

Response: EPA has reviewed these comments and disagrees that this rule should be fashioned specifically to serve several additional purposes beyond its primary intent of informing future policy. EPA had to balance cost burden on the industry with the quality and quantity of data necessary to address future policy, without biasing the data toward any particular policy. While direct measurement data is always very useful, this adds substantial cost. Much of the most useful and necessary data collected in today's final rule is the activity data: numbers of sources or frequency and duration of gas venting. Where publicly available, relatively recently collected data can be used for emission factors; this is a cost savings to industry. In cases where no credible, broad emissions data is publicly available, and emissions vary widely from site to site or by operating practice, EPA had to include the cost of direct measurement. The recent studies cited by this commenter, the Western Regional Air Partnership, and California Energy Commission, were not publicly available in time for vetting in the proposed rule. EPA may consider pertinent new data in the future as it becomes available. EPA cannot comment under this rule on any other programs to establish a separate sample and audit program aimed at maximizing the precision and accuracy of emissions estimating protocols. This is a policy outcome that may be considered based on the results of the MRR.

Comment Number: EPA-HQ-OAR-2009-0923-1201-13
Organization: North Slope Borough
Commenter: Edward S. Itta

<u>Comment Excerpt Text:</u>
A Robust Sampling and Audit Program is Needed to Ensure Continuous Improvement in Oil and Gas Reporting.

The dramatic underestimates in emissions from the oil and gas sector demonstrate a need to improve the quality of emission factors used in cases where direct measurement is not required, and the importance of providing well-audited emissions data to support quality policy-making. To that end, EPA should commit to a rigorous periodic statistical sampling and audit program, beginning immediately, in order to ensure continuous improvement in the data collected under the MRR. EPA should establish, either as part of this rulemaking or in a separate sample and audit program, a specific plan and detailed timeline for carefully measuring emissions and

[186] 39 Oil and Gas Exploration and Production Greenhouse Gas Protocol Task 2 Report on Significant Source Categories and Technical Review of Estimation Methodologies - Final Report, April 22, 2010. Available online at http://www.wrapair.org/ClimateChange/GHGProtocol/docs.html.

maximizing the precision and accuracy of its estimation protocols.
Such an audit program should in no way delay the issuance of reporting requirements for this sector. Rather, the goal of such a program should be to concurrently design and implement the program based on current estimates and then use the 2011 submittals to further refine the process, perhaps as early as 2012.

Because uncertainties in emissions estimates could result in large-scale data quality issues if they become ingrained, EPA should minimize uncertainties through sampling and auditing. The fragmented nature of this sector suggests that there will be many factors to consider in constructing a useful audit program. EPA should place a high priority on sources with the least certain reporting methods (e.g., pneumatic devices and onshore production and processing storage tanks) and on sources where wide variability in emissions has been demonstrated, such as well completions. EPA should consider the use of randomized samples, collected at varying times and locations, from sources with the highest potential emissions, and should place an emphasis on the top emitting source types.

Guidance on sources to target may be available from California's current efforts to improve its oil and gas inventory, which are planned for completion this summer.[187] Another available resource for helping determine the highest priority sources could be the Western Regional Air Partnership's recent screening inventory analysis for the oil and gas exploration and production sector, which was designed to help rank GHG source categories associated with exploration and production operations.[188]

Some sources may already be collecting samples that could be used as part of EPA's auditing program (e.g., in order to meet reporting requirements for ozone nonattainment area plans). For these sources, EPA could simply designate a certain percentage of samples for independent analysis and review.

Response: EPA disagrees that this rule should be fashioned specifically to serve several additional purposes beyond its primary intent of informing future policy. Also, EPA cannot comment under this rule on any other programs to establish a separate sample and audit program. For more information, see the response to EPA-HQ-OAR-2009-0923-1155-12.

Comment Number: EPA-HQ-OAR-2009-0923-1298-64
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

[187] The California Energy Commission has a contract to develop new natural gas system emission factors and the California Air Resources Board has a contract to develop new emission factors for oil fields. The timeline for both inventories is for completion in Summer 2010. See Oil and Natural Gas Production, Processing and Storage Public Workshop, CARB, Sacramento, California, December 8, 2009.

[188] Oil and Gas Exploration and Production Greenhouse Gas Protocol Task 2 Report on Significant Source Categories and Technical Review of Estimation Methodologies - Final Report, April 22, 2010. Available online at http://www.wrapair.org/ClimateChange/GHGProtocol/docs.html.

Comment Excerpt Text:
Emission Factors
Considerable expense and time would be required by operators for monitoring, lab analyses, and component counting to implement the proposed rule. Much of the information collected will not vary substantially from year to year and specific emission factors could easily be developed that would save operators both time and money without sacrificing the quality of the data or diminishing the overall goal of the GHG emissions reporting rule under 40 CFR 98. It is IPAMS' understanding that this substantial dataset will be made available by EPA to state regulatory agencies and the general public, and that statistically valid emission factors could be generated from these data. IPAMS has worked recently in conjunction with the Western Regional Air Partnership (WRAP) in a similar process that has developed improved criteria pollutant emissions inventory data for the oil and gas industry in the Intermountain West. Accordingly, IPAMS requests that EPA provide an option to allow reporters to use emission factors developed from data gathered from the initial reporting year for subsequent reporting years.

Response: Upon further analysis and review, EPA has determined that certain sources could take advantage of data collected in the first year and subsequent years to create company-specific emission factors that can be applied to similar activities and are periodically updated. Today's final rule includes several sources that apply this methodology, among which are gas well drilling completions using hydraulic fracturing, gas well liquids unloading, and different operational modes of large compressors (operating, standby pressurized and shut-down depressurized). EPA determined that the activity data collected, in conjunction with company and facility derived emission factors would provide cost-effective and suitable data for informing future policy. EPA may consider new data as it becomes publicly available, such as from the Western Regional Air Partnership, in future technical modifications of the rule.

13.1.1 POPULATION FACTORS

Comment Number: EPA-HQ-OAR-2009-0923-1065-6
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Delay reporting from the distribution sources for which the use of population emission factors has been proposed until more accurate emission factors are available, or commit to updating these emission factors as soon as more accurate ones are available;

Response: Please see the response to EPA-HQ-OAR-2009-0923-1065-11.

Comment Number: EPA-HQ-OAR-2009-0923-1151-126
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Sections 98.233(q) and (r) Fugitive Emissions

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

API believes that the methodology for arriving at a component count must be significantly changed to enable a reasonable approach to arrive at a component count for the hundreds of thousands of equipment and sites subject to the proposed rule. As currently structured, the rule would require a physical component count (along with concurrently gathering other information) at each well-site and associated facility. API's time and cost estimate for this inventory arrives at some 677 man years of time (at 2,000 hours per man year) and $168.7 MM necessary simply to inventory the specified components. To address this problem, API suggests the following:

- In lieu of the use of population counts and emission factors, API requests the option to use alternative emissions calculations for fugitive components where the methodologies are federally enforceable through state or federal permits.

- In a particular Sub-basin entity, operators tend to use similar equipment packages, such as separators, compressors, dehydrators, and tanks, and similar site layouts or configurations. API suggests that EPA modify the methodology for arriving at a component count for a particular Sub-basin entity as follows:

1. Require a component count for a small number (5) of each type of major equipment package. Inventory the number of each type of major equipment packages deployed in the Sub-basin entity. Multiply the component counts by the number of major equipment packages to arrive at a total component count for the major equipment packages.

2. Require a component count for a small number (5) of each type of site (e.g. single well-site, multi-well site, tank battery, central production site, etc) for components which are not part of the major equipment packages. Multiply the site component counts by the number of sites of each particular type to arrive at a total component count for components not part of the major equipment packages.

3. Sum the major equipment and site component counts for each Sub-basin entity to arrive at the total component count for the Sub-basin entity and then apply the methodology specified in the rule (Section 98.233 (r)) to arrive at a fugitive emission estimate for the Sub-basin entity.

4. Sum the fugitive emission estimates for all Sub-basin entities within an identified basin for purposes of annual reporting at the Basin entity level.

By making these modifications to estimate component counts, EPA can achieve a more appropriate balance between the burden of the rule and the amount of emissions covered while still yielding good quality emission estimates. Adopting this methodology would also partially address the issue of the industry's ability to physically meet the rule requirements in the time contemplated by EPA.

In addition, the minimum component size for leak survey should be defined (i.e., line size). API suggests that components associated with line size or tubing less than 2-inch outside diameter should be excluded because these components are expected to have minimal leakage while significantly adding to the burden on industry for collection of data associated with this smallest category of components. Ultimately, the leak detection and component count required should be consistent with existing leak detection and repair (LDAR) regulations to minimize additional burden required to collect data on these components.

Response: EPA disagrees with the commenter's request to allow onshore production reporters to count a small number of components and then to apply these counts across a "sub-basin entity" to calculate equipment leak emissions, as this would not represent "actual" emissions. EPA disagrees with the onshore facility definition as a sub-basin; please see response to comment EPA-HQ-OAR-2009-0923-1305-46. In order to manage burden while still gathering data necessary to inform future policy, EPA determined that, for equipment leaks in onshore production, the proposed rule's method to count the individual components and use population based emissions factors can be replaced with major equipment counts. The reporter would only count large equipment and apply a default average small component count based on the large equipment count. This will result in significantly less burden to reporters than counting each component (valve, flange, open-ended line, etc.) while sustaining the necessary quality of data, and thus EPA has revised today's final rule. For more information, please see "Equipment-Level Population Emission Factors for Onshore Production," EPA-HQ-OAR-2009-0923, and Section II.F of the preamble to today's final rule. However, reporters are still allowed the option to count components individually for a facility and apply the appropriate population emission factors. For counting components individually, EPA determined that tubing systems that are less than 0.5 inches in diameter are a small emission source and therefore, needn't be reported; EPA has revised today's final rule accordingly.

Comment Number: EPA-HQ-OAR-2009-0923-1011-48
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(r) Population count and emission factors

El Paso does not track all fugitive component counts for its pipeline and onshore oil and gas production operations. In evaluating the impact of the proposed rule requirements, El Paso estimates that it would have to locate and log over 1 million fugitive components across operations in ten states. Given the sheer number and geographic dispersion of fugitive components associated with onshore oil and gas operations alone, it is not possible to definitively account for all components, nor is it possible for EPA to verify the accuracy of the reported component counts for all operators. El Paso strongly encourages EPA to consider the trade off in emission accuracy between the use of component level emission factors applied to a count of components with a high degree of uncertainty due to the vast number of sources versus a slightly less accurate equipment level emission factor applied to a count of equipment that is known to a high degree of certainty. Furthermore this approach is more easily verified by EPA as well as the operators.

Given the geographic dispersion and number of small fugitive components, in addition to the disproportionate cost relative to the quantity of emissions, the rule should provide equipment level “population-based” counts and emission factors from industry accepted protocols such as the API Compendium, INGAA guidelines, etc. to quantify “population-based” fugitive emissions.

EPA states in the Preamble that the purpose of the Mandatory Reporting Rule is to guide policy development for future permitting and compliance purposes. General equipment-level emission counts are acceptable for this purpose, and therefore should be acceptable for petroleum and natural gas systems.

Response: EPA agrees with using onshore production major equipment counts for equipment leaks. Please see the response to comment EPA-HQ-OAR-2009-0923-1151-126.

Comment Number: EPA-HQ-OAR-2009-0923-1024-27
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Use of Population Emission Factors for Onshore Petroleum and Natural Gas Production and Gathering Pipelines. Although Kinder Morgan appreciates EPA’s emphasis on using population emission factors where possible, EPA has greatly underestimated the burden associated with applying population emission factors to the onshore petroleum and natural gas production sector. Many of the country’s approximately 450,000 wellheads, as well as the equipment associated with those facilities, do not have existing component counts. Carrying out component surveys at these sites would require considerable time and would be a highly labor-intensive process. Accordingly, Kinder Morgan recommends that EPA allow facility-level emission factors to be applied to onshore petroleum and natural gas production facilities, rather than requiring the application of component-specific emission factors. This method will yield data with acceptable accuracy and at much more reasonable cost than the proposed requirement.

Consistent with our recommendation above that Subpart W not require reporting of emissions from gathering pipeline segments, Kinder Morgan also recommends that the list of components for which population emission factors would be required under proposed 40 C.F.R. SECTION 98.233(r) be revised to exclude gathering pipeline fugitives in the onshore petroleum and natural gas production sector[189] and the natural gas processing sector.[190]

Response: EPA has revised t today’s final rule for equipment leaks in onshore production and allows the option to count major equipment and apply default average component counts per primary equipment; see the response to EPA-HQ-OAR-2009-0923-1151-126. EPA considered

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[189] See also proposed 40 C.F.R. SECTION 98.232(c)(9).

[190] See also proposed 40 C.F.R. SECTION 98.232(d)(8).

the comment to use facility level emission factors for onshore production, and has decided that it is not appropriate for the rule, as facility level emission factors are not available for the onshore production facility defined in this rule. As explained in Section II.E of the preamble to today's final rule, EPA has decided not to include monitoring and reporting requirements for gathering lines and boosting stations at this time.

Comment Number: EPA-HQ-OAR-2009-0923-1011-19
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233(r) Population count and emission factors. —El Paso recommends the use of a facility emission factor to be used as an alternative to population count for standard components at processing plants, onshore petroleum, transmission compression, underground storage, and LNG import facilities.

Response: EPA disagrees with the comment that facility level average emission factors should be used for gas processing facilities, onshore production, transmission compression, underground storage, or LNG import and export facilities. With regards to onshore production facility level emission factors, please see the response to EPA-HQ-OAR-2009-0923-1024-27. For gas processing facilities, transmission compression, underground storage, or LNG import and export facilities the facility level average emission factors are developed using "typical" facility activity factors and aggregated component emission measurements, and would not be reflective of the reporter's emissions, but rather average industry emissions. EPA deems this unacceptable data quality for the purposes of informing future policy. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). EPA is allowing equipment level reporting for onshore production; please see the response to EPA-HQ-OAR-2009-0923-1151-126.

Comment Number: EPA-HQ-OAR-2009-0923-0050-5
Organization: Southwest Gas Corporation
Commenter: Jim Wunderlin

Comment Excerpt Text:
Cost of Component Inventory. The discussion in the proposed rule demonstrates that there is a serious need on EPA's part to better understand natural gas distribution and transmission systems. EPA's proposal to use a population count of each fugitive emissions source (e.g., source types such as valves, connectors, etc.) multiplied by a population emissions factor simply will not work. Unfortunately an inventory of the types and numbers of components that are required to be inventoried for compliance with the proposed regulations is not readily available and it would be very costly and time consuming to compile this information.

Response: EPA disagrees with the comment on compliance cost. Please see the response to comment EPA-HQ-OAR-2009-0923-1020-5. EPA has analyzed the use of population emission factors and determined that it is a less burdensome method, and this remains in today's final rule. Please see the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027) Section Monitoring Method Options for further information.

Comment Number: EPA-HQ-OAR-2009-0923-1206-54
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The section on population count and emission factors includes emissions from gathering pipelines in Section 98.232(d)(8). This will require an operator to count and track every piping components [*sic*] along tens of thousands of miles of highly dispersed gathering pipeline, including tens of thousands or meter sites and valve settings. EPA has greatly underestimated the costs and resource requirement to conduct this population count, or they have perhaps failed to even consider the need to do this population count. Additionally, the gas quality can vary at every connection to a gathering pipeline. This would require that each pipeline segment be counted and tracked separately with the associated gas analysis applied to each segment.

Response: EPA has decided not to include monitoring and reporting requirements for gathering lines and boosting stations at this time. Please see response to comment EPA-HQ-OAR-2009-0923-1024-27.

Comment Number: EPA-HQ-OAR-2009-0923-1004-8
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
Restricting component population counts to components that are above a minimum size threshold.

Response: EPA agrees that a minimum size threshold is necessary. Please see the response to EPA-HQ-OAR-2009-0923-1151-126.

Comment Number: EPA-HQ-OAR-2009-0923-1016-25
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
Clarify Component Count Requirement .Proposed section 98.236(c)(19) "Data Reporting Requirements" states: "For fugitive emission sources using emission factors for estimating emissions report the following: (i) Component count for each fugitive emission source." If

reporting will be required by component count instead of by station or facility, AGA recommends that EPA:

- Clarify that only a count of leaking components by type are required to be reported, not a count of all components by type; and
  Establish a size threshold for components, such as 2” nominal diameter.

Response: EPA has clarified the data reporting requirements for equipment leak sources that use emission factors. Reporters that use leaker emission factors must report the total count of each type of component found leaking in a survey, as the commenter suggested. In addition, reporters that use population emission factors must report the total number of each type of component. EPA agrees, and a size threshold of 0.5 inches has been established. Please refer to EPA-HQ-OAR-2009-0923-1151-126 and EPA-HQ-OAR-2009-0923-1152-8.

Comment Number: EPA-HQ-OAR-2009-0923-1039-29
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

__**Comment Excerpt Text:**__
§98.233(r) references to §98.232(e)(6) and (f)(4) should be deleted: Low bleed pneumatic devices are identified as a source for gas transmission compression in §98.232(e)(6) and the emission estimation method is appropriately detailed in §98.233(b). This estimate uses population-based EFs from Table W-3. However, §98.233(r) also indicates that the estimation method in that paragraph applies to §98.232(e)(6). Since §98.233(b) already addresses estimates for this source type, any further delineation in §98.233(r) would be duplicative. It is apparent that the reference to “(e)(6)” in §98.233(r) is an error and “(e)(6)” should be deleted from the list of emission sources in §98.233(r).

In addition, the reference to “(f)(4)” as an emission source in §98.233(r) is inappropriate and should be deleted. Similar to the discussion above, §98.232(f)(4) identifies low bleed pneumatic devices as a source for underground storage and the estimation method is already addressed under §98.233(b).

Response: EPA has reviewed this comment and has decided to remove the reference to natural gas pneumatic device venting from 40 CFR 98.233 (r) in today’s final rule, as those sources have their own specific methodologies..

Comment Number: EPA-HQ-OAR-2009-0923-1039-8
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

__**Comment Excerpt Text:**__
High Bleed and Low Bleed Natural Gas-Driven Pneumatic Devices §98.233(a) and (b) provide emission estimates based on emission factors for high bleed and low bleed natural gas-driven pneumatic devices, respectively. Low bleed devices are defined as devices with gas bleed rates

less than or equal to 6 scf/hr. For low bleed devices, a Subpart W population emission factor is used. Emissions from all low bleed devices are calculated from the count of low bleed devices, the population emission factor, and an assumption of 8,760 operating hours per year. High bleed devices are defined as devices with gas bleed rates greater than 6 scf/hr. Equation W-1 is used to estimate gas emissions from each high-bleed device: [See original attachment for equation]

The emission factor (Bs) is the device bleed rate provided by the manufacturer or based on data for a similar device. Annual operating minutes (T) for each device must be determined.

INGAA accepts these methods for pneumatic device emission estimates with the request that two clarifications be provided in the Final Rule:

(1) "time" basis for high bleed devices is facility operating time and not related to time based on device actuation; and
(2) definitions of "low-bleed pneumatic device" and "high-bleed pneumatic device" in §98.6 are revised to clarify that applicability is based on continuous bleed rate and facility operating time.
Further, it is INGAA's understanding that pneumatic devices addressed under §98.233(a) and (b) are continuous bleed devices and not intermittent devices. Thus, valve actuators with intermittent releases are not covered by this section and intermittent release valve actuators do not meet the definition of high-bleed or low-bleed pneumatic device under Subpart W. For natural gas transmission and storage, valve actuator components would be screened during the leak survey required under §98.233(q).

Response: Today's final rule has been revised such that high bleed pneumatic devices will report emissions using an emission factor with an assumption of 8,760 operating hours per year. EPA determined that monitoring the operational time for each high-bleed pneumatic device is overly burdensome. EPA agrees that the definition of pneumatic devices needed clarification, and therefore in today's final rule has clarified the definition for high-bleed and low-bleed pneumatic devices to state that they are continuous bleed devices. Furthermore, in today's final rule, intermittent bleed devices are also required to report emissions. A definition for intermittent bleed devices has been added to 40 CFR 98.6. In addition, this commenter misinterpreted the EPA's intent regarding leak detection on valve actuator components in transmission and storage facilities. EPA does not require reporters to conduct leak detection surveys on pneumatic devices in the transmission and storage sector.

Comment Number: EPA-HQ-OAR-2009-0923-1060-16
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
First, the term definitions for Eq. W-19 refer to "facilities listed in 98.230(b)(3) through (b)(8)." However, 98.230(b) is marked reserved, so this reference is incorrect.

Response: EPA agrees and in today's final rule, the reference has been revised to refer to the appropriate facilities.

Comment Number: EPA-HQ-OAR-2009-0923-1065-11
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Emission Factors. For LDC pipelines and below grade M&R stations, the proposed rule requires a population count of emissions sources and use of population emissions factor to estimate fugitive emissions. While the Clean Energy Group agrees with this approach, we recognize that fugitive and vented emission factors for the oil and gas sector are outdated and uncertain, and that emission factor studies are ongoing that will likely provide more accurate emission factors for the industry. Therefore, the Clean Energy Group recommends that EPA delay requiring emissions reporting from these sources until more accurate emission factors are available. Alternatively, we encourage EPA to commit to updating these emission factors as soon as more accurate ones are available.

Response: EPA disagrees with this comment to delay reporting from sources that calculate emissions using population emission factors. EPA used best available, public data to develop the emission factors in Table W-1 through W-7 of today's final rule. If and when new data become available, EPA will consider the need to update the emissions factors. All other alternatives considered were either less recent or more prone to erroneous calculations than the data EPA used. Moreover, EPA developed the emission factors with the intent of minimizing the reporting burden on reporters. Where used in today's final rule, population emission factors are the least burdensome method for reporters, while sustaining the necessary quality of data. In addition, EPA will evaluate the natural gas distribution data received through the MRR, which are based on emission factors and methodologies in subpart W. EPA will also evaluate other emission factors that EPA may receive. EPA may also consider using direct measurement of equipment leaks and vents if EPA deems the natural gas distribution emissions data received through the MRR is insufficient to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-1065-4
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
If distribution facilities must report fugitive emissions from above-ground M&R stations, allow the use of population emission factors in order to reduce reporting costs.
If the use of population emission factors to report emissions from above-ground M&R stations is not allowed, redefine distribution facilities to exclude small, remote sub-systems in order to reduce reporting costs.

Response: The commenter made several assumptions which were not consistent with EPA's intent. One was the assumption that EPA required leak detection and calculating emissions from customer meters. Reporters are not required to calculate emissions from customer meters. EPA has clarified this in today's final rule. Please see Section II.F of the preamble to today's final rule. Furthermore, in today's final rule, above-ground meters and regulators at city gate station at custody transfer are required to use leak detection and leaker emission factors to calculate emissions. For above-grade meters and regulators at city gate stations not at custody transfer, reporters must develop a facility emission factor using emissions and meter count from the leak detection surveys conducted at the custody transfer city gate stations. This facility emission factor, along with a count of meters at the non-custody transfer city gate station, is used to calculate emissions from above-grade meters and regulators at city gate stations not at custody transfer.

Comment Number: EPA-HQ-OAR-2009-0923-1099-16
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

<u>Comment Excerpt Text:</u>
Monitoring methods and emissions quantification for: LDC pipeline mains and service lines (98.232(i)(3) and (4))

How do you calculate fugitives from distribution pipelines using the population count method? The emission factor in Table W-7 says the units are scf per hour per service. What does EPA mean by "service"? Did EPA intend to mean miles of pipeline? If EPA means miles of pipeline, the only way to reduce emissions would be to change the pipe material. It would seem that if a company where able to show proper maintenance records than the factors should be reduced.

Response: It appears as though the commenter misunderstood the method of calculating emissions from LDC pipeline mains and service lines.   To calculate emissions from distribution mains, the number of miles of distribution mains pipeline are multiplied by a population emission factor with units of standard cubic feet per hour per mile of pipeline. To calculate emissions from distribution service lines, the number of service lines branching off from the main distribution line is multiplied by a population emission factor with units of standard cubic feet per hour per number of services. EPA does not require the use of leak detection and leaker emission factors, which would better represent "actual" emissions, because this would be unduly burdensome.

13.1.2 LEAKER FACTORS

Comment Number: EPA-HQ-OAR-2009-0923-0049-9
Organization: American Gas Association
Commenter: Pamela Lacey

<u>Comment Excerpt Text:</u>
Third, EPA should delete the requirement to apply "leaking" emission factors to leaking components at city gates and above ground M&R stations, and instead, EPA should allow LDCs to use a facility level emission factor for city gates and both above ground and below ground M&R stations.

Response: EPA disagrees with using a facility level emission factor for above and below ground meters and regulators at city gate stations. Please refer to EPA-HQ-OAR-2009-0923-1065-4.

Comment Number: EPA-HQ-OAR-2009-0923-0050-4
Organization: Southwest Gas Corporation
Commenter: Jim Wunderlin

Comment Excerpt Text:

Cost of Improving Emission Factors
It is well known that the accuracy of existing emission factors varies by as much as 2,000%. There have been significant efforts made to improve those accuracies within the last two years by the AGA and individual companies, such as Southwest, who have implemented direct measurement programs to further enhance the base information from which emission factors are derived. While any new information will be helpful, the cost of this work and the time needed to do the work does not appear to be adequately addressed in the justification for the proposed rule. EPA found that emission factors generated from the Clearstone studies related better to methane-rich stream fugitives and were more appropriate than other emission factors developed for highly regulated refinery and petrochemical plants on VOC emissions. Therefore, EPA is using emissions data from the Clearstone studies as the basis for the leak factors proposed in this rule. Due to the extremely short comment period, Southwest does not have time to thoroughly evaluate the emission factors from the Clearstone studies. Southwest has no comfort that this alternative approach better estimates annual facility emissions without resulting in additional reporting burden for the facilities. Multiple surveys only add to the confusion that EPA has already created in attempting to promulgate this rule.

Response: EPA disagrees that the emission factors in the rule are inaccurate. EPA used the Clearstone studies to develop the emission factors in today's final rule, as it is the best available public data on transmission and distribution facilities. Please see the TSD EPA-HQ-OAR-2009-0923. All other alternatives considered were either less recent or more prone to erroneous calculations than the data EPA used. Moreover, EPA developed the emission factors with the intent of minimizing the reporting burden on reporters. Where used in today's final rule, emission factors are the least burdensome method for reporters that sustains the necessary quality of data.

EPA disagrees that multiple surveys are confusing. Multiple surveys would improve data quality, as a leak would not be assumed to be ongoing based on the data from the last regular leak survey. Therefore EPA is allowing reporters to voluntarily submit data from multiple leak detection surveys in today's final rule. EPA deliberated on the issue and determined that assuming that a leak perpetuates for the duration of a reporting period may overestimate emissions. Allowing multiple surveys allows reporters to adjust emissions for a component found leaking and not leaking, respectively, between two consecutive leak detection surveys.

EPA disagrees with the comment regarding the benefits of today's final rule. Please see the Section III.E of the preamble to today's final rule. In addition, EPA does not need to include in the rule's cost burden analysis the cost incurred by reporters to conduct their own emission measurement studies that are outside the scope of the rule.

Comment Number: EPA-HQ-OAR-2009-0923-0055 -14
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

<u>Comment Excerpt Text:</u>
<u>Measurement Complexities</u>
Although simple in principle, the proposed measurement techniques require substantial experience to perform correctly. Considerations include:

1. H-Flow enclosures must be placed so as not to restrict air flow and allow full capture of leaks.
2. The back ground probe for the H-Flow sampler must be placed in the correct position to determine if there is any interference from other sources as well as to determine whether or not complete capture of the leak has been achieved.
3. The vent bag technique must be first practiced under metered conditions in order to be confident of the results. Personnel must be aware of how to eliminate potential errors due to leaks, restricted openings, or flow induced by Venturi effects.
4. Some vents may be manifolded together, sometimes going to a larger diameter (six feet) silencer. Larger diameter vent stacks have been measured previously with the use of covers, but this technique requires practice and great attention to safety considerations. It may not be possible to know which source is the leak in these cases.

<u>Contribution of Standard Components to Total Leakage</u>
There may be an overemphasis on the importance of standard components at compressor stations due to Clearstone Engineering's studies at gas plants in 2002 and 2006. Although these studies were detailed and well executed, gas processing plants have a much larger ratio of standard components per compressor unit than is found at transmission compressor stations. For instance, in the PRCI study done at thirteen transmission compressor stations, the number of components per compressor unit was a little over 400. The Clearstone studies don't list a complete inventory of compressor units, but if there were twenty units at each site, the ratio of components to compressor units would be approximately 1000, about two and one half times greater than at transmission sites. Additionally, standard components at processing plants may be subjected to greater heat and vibration in some areas than at transmission compressor stations.

The 2002 Clearstone study (EPA, 2002) indicated that connectors and valves accounted for over 50% of the total leakage (Figure 10 of that study), whereas at transmission stations that number is more likely to be 20% (Howard et al, 1999). Additionally, the 2006 Clearstone study (KSU, 2006) indicates that connectors and valves were down to approximately 32% (Figure 13 of that study). Open ended lines contributed another 30%, but this category apparently includes compressor blow down valve leakage which would probably dominate the leakage.

It is understood that for the purposes of the proposed rule that different leaker emission factors have been developed for transmission as opposed to processing. However, the key point is that standard components in transmission don't contribute to the total leakage as much as the

Clearstone studies might be interpreted to suggest.

Response: With regard to measurement complexities, EPA disagrees that the four points the commenter discusses will prevent compliance with subpart W. In today's final rule, leak measurement using the instruments listed is only required for compressors. Reporters are to measure the manifolded vents in the operating mode in which the compressor is found. The rule provides guidance on how to properly use calibrated vent bags and high volume samplers; however, it also states that it is the responsibility of the reporter to follow all manufacturer instructions to ensure quality measurement. Reporters may also contract these measurements out to trained personnel. Today's final rule further allows reporters to apply for the use of best available monitoring methods, should the reporter have trouble accessing staff to perform this work. Please see Section II.F of the preamble to today's final rule. In addition, the use of acoustic detectors is also allowed in today's final rule for through valve leakage for compressors and transmission storage tanks. EPA's decision to include standard components is based on the criteria under Selection of Emissions Sources for Reporting in the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027). The standard components met the criteria and were subsequently required to report in today's final rule. Upon further analysis and review, EPA has revised the leaker emission factors for transmission and processing to be the same. Please see the memo "Revisions to Processing Leaker Emission Factors in Rule Table W-2" in EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-0055 -8
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

<u>Comment Excerpt Text:</u>
Detection/Leaker Emission Factors for Standard Components at Transmission Compressor Stations.

Currently, Section 98.233 (q) requires surveying standard components (such as connectors and valves, as opposed to vented components) with an IR camera and then applying a "leaker" emission factor to the number of leaks found at each component type.

It's clear that EPA's intent was to reduce labor costs in this area. However, this approach still requires a substantial amount of effort that does not provide a large improvement in the accuracy of the reported emissions. It would also distract from collecting accurate data from the vented components that make up the majority of fugitive emissions.

The contribution of leakage from standard components averages about 20% of the total leakage at transmission compressor stations (Howard et al., 1999 – this was a joint study sponsored by PRCI, GRI, and EPA.). Because the proposed method still uses an emission factor as opposed to a measurement, there will still be uncertainty in this method. The EPA Natural Gas Star program has previously developed emission factors for compressor stations based on the number of compressor units at the site (EPA, 2000). These factors include both standard and vented components but could easily be recalculated to assess only standard components.

Although the proposed method of using leak detection combined with leaker emission factors would be expected to give better results than applying a facility emission factor, this improvement only applies to approximately 20% of the total facility leak rate. Consequently, the improvement in the reporting accuracy for the entire facility is probably less than 5%, while the effort involved might require as much as 50% of the total leak survey effort.

Allowing a facility emission factor for standard components as an option to leak screening lets facilities focus on making measurements at the vented components that account for 80% of the total emissions. This full focus should improve the accuracy of the data collected from these key sources.

Should EPA still feel that leak surveys of standard components are essential, it would be better to allow more options than just the IR camera to conduct these surveys. Although these cameras are useful tools, screening with flame ionization detectors, catalytic oxidation/thermal conductivity detectors, and soap solutions have been proven to be effective (Howard et al., 1999; EPA, 2002; KSU, 2006) and should not be excluded.

It's possible that EPA felt that the IR cameras would be the most cost effective approach, and for some companies, that may be true. However, other companies might want to have in-house personnel conduct leak screening with techniques that they already know how to use. Clearstone's 2006 study (KSU, 2006) notes that a 2 person crew with an IR camera can survey approximately 6400 components per day. The PRCI study (p. A-1-14) found that experienced personnel could survey transmission station components using a combination of soap and catalytic oxidation/thermal conductivity detectors at a rate of 350 components per person per hour, or 5600 components per two person crew per eight hour day. During this time study, the personnel found 99.6% of combined leaks found by using this method and a Foxboro TVA – 1000, so these methods are clearly still effective.

Facilities that have access to IR cameras and trained personnel could apply the IR camera if they so desired. Other facilities without these resources could rely on past experience and conduct the leak screening on a flexible time schedule without necessarily acquiring more equipment or hiring contractors.

A further discussion of the contribution of standard components is given in the appendix of this letter.

Response: EPA disagrees, and did not include transmission compressor station facility-level average emission factors because they do not provide sufficient quality emissions data to inform future policy; please refer to EPA-HQ-OAR-2009-0923-1011-19. EPA selected leak detection and leaker emissions factors versus other options as it provides a more accurate calculation of emissions from each piece of equipment and reduces burden. Please see Section II.E of the preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002). Further, EPA included transmission compressor station equipment leaks as they fell within the 80/20 criteria in the TSD. Please see the TSD in EPA-HQ-OAR-2009-0923. EPA has noted the prevalence of other methodologies for leak detection and has included several additional leak detection techniques including flame ionization detectors, catalytic oxidation/thermal conductivity detectors, and soap solutions as per Method 21; please see Section II, Petroleum and Natural Gas Systems, of the Preamble for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0837-6
Organization: Canadian Gas Association
Commenter: Michael Cleland

Comment Excerpt Text:
Inclusion in the MMR: We think it is important to take into consideration the fact that both industry and governments continue to conduct field research to improve the quality and basis for fugitive emission factors. We know that these factors will continue to be updated, possibly quite frequently. We strongly suggest that EPA remove the emission factors from the rule itself to a reference source where emission revisions can be more readily published.

Use of GRI-EPA emission leaker factors: The EPA's TSD (p. 40) cites several concerns with these emission factors concluding that "this method for estimation of the emissions is not considered to be appropriate for a mandatory GHG reporting program." Additionally, these factors do not align with more recent and representative field work done in Canada. The use of these default emission factors risks generating a skewed national-level inventory for the sector that is not representative of current-day LDC facilities. It is also worth noting that odorized systems, which are the norm in LDC service, have demonstrably lower leak emission rates than non-odorized systems.

Response: EPA disagrees that emission factors in the rule are not representative of the U.S. industry. EPA used best available, public data to develop the emission factors in Table W-1 through W-7 of today's Final Rule. In addition to GRI studies, for distribution EPA also used data from Canadian studies "Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry" 2007 and "Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems" 1998. Please see the TSD in EPA-HQ-OAR-2009-0923. All other alternatives considered were either less recent or more prone to erroneous calculations than the data EPA used. Moreover, EPA developed the emission factors with the intent of minimizing the reporting burden on reporters while maintaining the necessary quality of data. EPA disagrees that EPA should remove the emission factors from subpart W and place them in another reference technical document. Please refer to EPA-HQ-OAR-2009-0923-1299-5. In addition, EPA will evaluate the natural gas distribution data received through the MRR, which are based on emission factors and methodologies in subpart W. EPA will also evaluate other emission factors that EPA may receive. EPA may also consider using direct measurement of equipment leaks and vents if EPA deems the natural gas distribution emissions data received through the MRR insufficient to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-0954-2
Organization: Verdeo Group
Commenter: John Savage

<u>Comment Excerpt Text:</u>
S98.233 (q) Leak detection and leaker emission factors

This section requires the use of component counts and emission factors for calculation of emissions detected from specified sources. A more accurate approach would be the use of a measurement device such as a high volume sampler or comparable methane leak detector.

Verdeo recommends that Section (q) be amended to allow (not require) companies the option of measuring leaks with such devices. Some companies may already be using such equipment as part of their site survey to collect data for the MRR. They may elect to invest the incremental time required to take an accurate direct measurement of leak rates in order to help them prioritize future investments in leak reduction processes or technologies. If they choose to do so and have the data available, they should be encouraged to submit it in their report. The company should simply indicate on their report if the leak data was derived from a direct measurement or the use of an emission factor.

Response: EPA disagrees that it should provide an option for reporters to submit measured data for equipment leak emissions. In the April 2009 proposed rule, EPA required reporters to measure their equipment leaks; however, many potential reporters commented that the cost burden was too high. EPA accepted these comments and revised the rule to population emission factors and leaker factors to reduce compliance burden on industry while maintaining the necessary quality of data to inform policy. Please see Section III of the preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002).

Comment Number: EPA-HQ-OAR-2009-0923-1082-7
Organization: MidAmerican Energy Holdings Company
Commenter:

<u>Comment Excerpt Text:</u>
Natural gas transmission and distribution facilities are highly regulated by other regulatory bodies, including the U.S. Department of Transportation through its Pipeline and Hazardous Materials Safety Administration, the Federal Energy Regulatory Commission, and state regulatory agencies. While these regulatory bodies do not specifically regulate greenhouse gas emissions, they are responsible for developing and enforcing strict gas leak response and repair requirements and safety standards. As a result of the imposition of these requirements, MidAmerican believes that on both the natural gas transmission and distribution side, EPA’s proposed fugitive default factors are overstated for leaks; that the leak duration assumptions (365 days) dramatically overstate the true duration of a leak and, as a result, overstate emissions; and, that the requirement to annually measure leaks from regulator stations is unnecessary. MidAmerican recommends that EPA obtain additional information regarding leak detection, response, and repair be sought from the pipeline safety organizations prior to finalizing the monitoring and reporting rules.

Response: EPA disagrees that rule is unnecessary because of DOT regulations. EPA conducted extensive research on all applicable transmission and distribution-sector related regulations in place today that might have similar requirements to subpart W, including consultations with Department of Transportation experts. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923) "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements." In today's final rule, EPA does not require leak detection at all regulator station; please see the response to EPA-HQ-OAR-2009-0923-1065-4. In addition, leak detection is not required at below-grade M&R, and instead use population emission factors. EPA agrees that assuming a leak duration of 365 days may overestimate emissions and is allowing adjustment of emission in today's final rule; please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-0955-7
Organization: American Public Gas Association (APGA)
Commenter: Bert Kalisch

Comment Excerpt Text:
The Final Rule should allow LDC operators to estimate emissions at above-ground M and R Stations together with the use of recent emissions data.

By operation of Section 98.233 (q), all LDC facilities identified by Section 98.232(i)(1) are required to be leak surveyed annually. Yet, as noted, under PHMSA's pipeline safety regulations LDC's conduct leakage surveys of their entire system at least once every 5 years. Some LDC operators leak survey their above ground facilities at least once every three years to coincide with a 3 year requirement to inspect the facilities for atmospheric corrosion.

APGA urges EPA to allow LDC's the option of maintaining their existing 3 or 5 year leakage survey cycles and to allow an estimate of emissions using an emission factor for facilities identified in Section 98.232 (i) (1) in years when no leakage survey is conducted on a given facility. A population emission factor would need to be developed.

Response: EPA disagrees, as current leakage surveys as prescribed by DOT regulations are not applicable to subpart W as they focus on safety and therefore gas concentration levels rather than specific emissions sources and the volume of emissions from said leak source. Therefore EPA will not allow LDCs to apply in subpart W the data gathered to meet the safety requirements under existing DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-1082-7. EPA disagrees that direct measurement of sources is not necessary. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). EPA disagrees with less than annual reporting. Please see Section II.H of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98).

Comment Number: EPA-HQ-OAR-2009-0923-0961-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
(98.233 (q)) What is the definition of a for use in the fugitive emission equation (Eq. W-18)

Response: In the rule paragraph 98.233(q), the definitions of emission sources are found in subpart W and in the Final MRR.

Comment Number: EPA-HQ-OAR-2009-0923-1011-16
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
XVI. Proposed Rule Section 98.233(q) Leak detection and leaker emission factors — El Paso requests monitoring flexibility and urges the use of a facility emission factor to be used as an alternative to Infra-red (IR) camera leak detection/leaker emission factors for standard components at transmission compression and underground storage facilities.

Response: EPA disagrees, and did not include facility level average emission factors because it does not provide sufficient activity data to inform future policy; please refer to EPA-HQ-OAR-2009-0923-1011-19.

Comment Number: EPA-HQ-OAR-2009-0923-1011-8
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
VIII. Proposed Rule Section 98.233(a) Natural gas pneumatic high bleed device venting.—El Paso encourages the EPA to provide a default leak rate for those devices where manufacturer and model is not known.

Response: Based on comments received, EPA has revised today's final rule to allow the use of population emission factors for pneumatic device venting emissions, this will reduce burden on the industry while maintaining the necessary quality of data to inform policy. This will eliminate the need to determine the device manufacturer model. EPA's decision to include a default leak rate was partially related to the difficulty of ascertaining the manufacturer and model in certain cases. EPA determined that the burden of determining the manufacturer and bleed rate of each reporting pneumatic device was unnecessary, as the collection of activity data and the application of emissions factors will not adversely affect the quality of reported data allowing consideration of future policy options.

Comment Number: EPA-HQ-OAR-2009-0923-1015-39
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:

General Comments – Use of Leak Detection and Leaking Component Emission Factors

98.233(q) requires direct measurement of leaks. In the preamble on page 18623, the EPA concedes that fugitive emissions detection for onshore petroleum and natural gas production is particularly challenging due to large geographical operations. PAW agrees with this statement. Also on page 18623 of the preamble, the EPA proposes that, "if a component fugitive emission is detected, emissions are assumed to occur the entire 365 days in the year." What if a leak is repaired the same day it is detected? It seems the EPA should at least let the operator prorate the leak from the beginning of the year to the day it was known to be repaired.

Response: EPA agrees to allow multiple leak detection surveys, please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1016-21
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
Allow the Use of a Leak Longevity Factor to Permit More Accurate Estimates of Methane Leaks at M&R and Gate Stations
EPA proposes to apply a "leaker" emission factor to components found to be leaking during leak surveys of M&R and city gate stations. These leaker emission factors assume that the leak occurs for 365 days during the year, which will significantly overstate emissions for most leaks. AGA recommends an alternative that will lead to more accurate emissions estimates by including a leak longevity factor in the calculation.

LDCs typically maintain systems that allows them to estimate the magnitude of a methane leak caused by a contractor hitting a gas line, in order to facilitate billing the contractor afterward for the resulting "third party damage" and the costs of repairing the leak. In addition, LDCs respond to leak calls generally within two hours or less, they know the leak began shortly before the caller was able to smell the odorized gas, and the LDC fixes the leak promptly. Thus for such leaks, it is possible to put a time bracket on the leak of 6 hours or less. To estimate emissions from the leak, one can apply the allocable portion of the 365-day leaker emission factor (e.g. a leak lasting one day would equate to the leaker emission factor divided by 365.

Response: EPA disagrees with the comment's proposed method for equipment leaks and leaker factors for LDC, since it uses methods under DOT regulations. Please see response to comment EPA-HQ-OAR-2009-0923-0955-7. However, EPA is allowing multiple leak detection surveys; please see the response to EPA-HQ-OAR-2009-0923-1014-9. The rule's multiple leak detection surveys method calls for the component found to be leaking to be calculated from the beginning of the year or since the previous leak detection survey.

Comment Number: EPA-HQ-OAR-2009-0923-3541-2
Organization: Sempra LNG
Commenter: David M. Cobb

Comment Excerpt Text:
Under 98.233 (q), the EPA assumes that, if a fugitive emission source is detected, the emissions would occur the entire 365 days of the year. This assumption is inaccurate, as LNG facilities cannot and do not permit such conditions as LNG valve leakage to continue after detection. When leaks are detected, they are quickly corrected.

Response: EPA is allowing multiple leak detection surveys; please see the response to EPA-HQ-OAR-2009-0923-1014-9. The rule's multiple leak detection surveys method calls for the component found to be leaking to be calculated from the beginning of the year or since the previous leak detection survey.

Comment Number: EPA-HQ-OAR-2009-0923-1060-13
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Use of Leak Detection and Leaking Component Emission Factors

98.233(q) requires direct measurement of leaks. In the preamble on page 18623, the EPA concedes that fugitive emissions detection for onshore petroleum and natural gas production is particularly challenging due to large geographical operations. Yates agrees with this statement. Also on page 18623 of the preamble, the EPA proposes that, "if a component fugitive emission is detected, emissions are assumed to occur the entire 365 days in the year." What if a leak is repaired the same day it is detected? It seems the EPA should at least let the operator prorate the leak from the beginning of the year to the day it was known to be repaired.

Response: The commenter misinterpreted the requirements of the proposed rule for leak detection and leaker emission factors. The EPA does not require reporters to directly measure the leaks. Instead, EPA requires reporters to determine leaking components and apply a leaker emission factor. EPA agrees with the commenter's point about improving the accuracy of emissions estimates to account for leak repairs and is allowing multiple leak detection surveys to address this. Please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1025-3
Organization: Paiute Pipeline Company
Commenter: Jeff Maples

Comment Excerpt Text:
Revise and Clarify Provisions for LNG Storage Facilities
EPA should not apply "leaker" emission factors at LNG facilities because leaks are rare and fixed immediately. EPA assumes that if a fugitive emission source is detected, the source must have continued to leak for all 365 days of the year. This hypothetical assumption would vastly overstate emissions and would not yield useful data for policy development. Leaks are rare at

LNG facilities and located / resolved in a timely manner. These facilities are very tight by design and operation. LNG facilities cannot and do not permit conditions such as LNG valve leakage to continue after detection. Detection of leaks is rapid due to installed fixed gas detection, low temperature spill detection and physical facility inspections by qualified operating staff. When leaks are detected, they are generally corrected immediately. Thus, using a "leaker" emission factor that assumes the leak continues all year would seriously overstate fugitive emissions at an LNG storage facility or import terminal.

Response: EPA disagrees that LNG emission factors in the rule will not yield useful data to inform future policy. EPA is allowing multiple leak detection surveys; please see the response to EPA-HQ-OAR-2009-0923-1014-9. The rule's multiple leak detection surveys method calls for the component found to be leaking to be calculated from the beginning of the year or since the previous leak detection survey.

Comment Number: EPA-HQ-OAR-2009-0923-1028-1
Organization:
Commenter: Michael Leonard

Comment Excerpt Text:
(98.233 (q)) The source category for Leak detection and leaker emission factors applies to emission sources with streams with gas contents greater than 10 percent CH_4 plus CO_2 by weight. We propose this source category be revised to include only CH_4, as the infrared absorption curve of CO_2 does not allow CO_2 to be visible using current Optical Gas Imaging technology. Current Optical Gas Imaging cameras can locate gases with absorbance curves in the 3.3 to 3.5 micrometer range of the electromagnetic spectrum, while the absorbance curve of CO_2 is in the 4.17 to 4.5 micrometer range of the electromagnetic spectrum and therefore cannot be easily detected using OGI technology.

Response: EPA recognizes that the infrared cameras commercially available today do not detect CO_2. EPA considered the sources of GHG equipment leak emissions and determined that with rare exceptions (e.g., CO_2 EOR) the gas streams are predominantly hydrocarbons detectible by IR camera and typically have a minor CO_2 content. The method referenced for use of the IR camera requires the camera to be able to detect the potentially leaking constituents at a certain leak rate, and this will insure that the IR camera is a suitable leak detection method for streams required to be surveyed in today's rule.

Comment Number: EPA-HQ-OAR-2009-0923-1060-25
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type: Fugitives from valves, connectors, OELs, pressure relief valves, meters, and centrifugal compressor dry seals, pumps, flanges, starter gas vents and other fugitive sources.
Regulatory reference for calculation/ monitoring requirements: 40 CFR 98.233(q)

Monitoring requirements/parameters:

- Total number of this type of emission source found to be leaking
- For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(3) through (a)(8), GHG_i equals 1.
- Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

Comment: Direct measurement of leaks is very burdensome and expensive, particularly since many upstream activities requiring FLIR surveys are operated in remote locations and difficult to reach. The EPA has repeatedly stated that accessibility is a key factor in determining which sources to require direct measurement. Of these sources, many of these sites are not easily accessible to Yates staff.

Response: The commenter has misinterpreted the proposed rule, which does not require direct measurement of leaks from sources listed under 98.233(q) for leak detection and leaker emission factors. Instead, EPA is requiring leak detection at these sources using methods described in 40 CFR 98.234 (a). In today's final rule, EPA has not limited the leak detection methods to just optical gas imaging devices. Instead, EPA has included techniques acceptable under 40 CFR part 60 (Method 21), and infra-red laser beam illuminated instruments; please see Section II., Petroleum and Natural Gas Systems, of the preamble for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1074-15
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
75 FR 18623: Use of Leak Detection and Leaking Component Emissions Factors
Comment: WBIH requests flexibility with the leak detection monitoring through the use of any industry accepted instruments or practices. Optical gas imaging instruments are costly and should not be mandated as the only monitoring method for leak detection when leak detection with soap solution is an accepted, standard industry best practice. Also, EPA should not make an assumption that a contractor would be hired when it is unknown if there is the required number of contractors to provide leak detection with optical gas imaging instruments.

Response: EPA has included several additional leak detection techniques including Method 21 and infra-red laser beam illuminated instruments; please see Section II of the preamble for further details. Regarding contractors to provide leak detection, EPA has revised the rule to include Best Available Monitoring Methods. Please see Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1061-5
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:

Duplicative provisions in proposed § 98.233(q) should be deleted. Proposed § 98.233 prescribes various calculation methods for different emission source categories. Subparagraph (q) provides certain calculation methods for sources listed in, inter alia, §§ 98.232(f)(5), (g)(3), and (h)(4) (generally relating to fugitive emissions). However, subparagraph (r) also provides calculation methods for sources listed in §§ 98.232(f)(5), (g)(3), and (h)(4). The duplicative coverage should be eliminated, and the reference to sources listed in §§ 98.232(f)(5), (g)(3), and (h)(4) should be struck from subparagraph (q).

Response: EPA disagrees with the comment on duplication of emissions sources under 98.233(q) for leak detection and leaker emission factors and 98.233(r) for population count and population emission factors. In 98.232(g)(3), (h)(4) and (f)(5) are listed equipment leak sources that require either a leaker emission factor or a population emission factor.

Comment Number: EPA-HQ-OAR-2009-0923-1039-30
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Leaker versus population emission factors for underground storage: For natural gas underground storage, fugitive emissions are identified as an emission source in §98.232 (f) (5). Based on Table W-4, emission estimates employ population EFs for storage wellhead components and leaker EFs for the balance of station components. Thus, §98.232 (f) (5) is cited in both §98.233 (q) for leak surveys and leaker EFs and §98.233 (r) for population EF-based estimates. To avoid confusion on which EFs are used, which portion of the facility requires leak survey, and potential double counting, additional clarity is desired. This could be addressed by adding the following to the end of §98.233 (q) (4):

"…For underground storage facility components in storage wellhead service, population emission factors apply under §98.233(r) and a leak survey is not required."

Response: EPA disagrees with the comment. Please refer to EPA-HQ-OAR-2009-0923-1061-5.

Comment Number: EPA-HQ-OAR-2009-0923-1206-52
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The requirements for leak detection and leaker emission factors would apply to emissions from several source categories, including Sections 98.232 (f)(5),(g)(3), and (h)(4). These three sources are also covered by Section 98.233(r) and should be deleted from this section to avoid double reporting.

Response: EPA disagrees with this comment; please refer to EPA-HQ-OAR-2009-0923-1061-5.

Comment Number: EPA-HQ-OAR-2009-0923-1298-43
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Leak detection and leaker emission factors

Section 98.233(q): The proposed rule requires that leak detection surveys be conducted annually for fugitive emissions from specific source types within each sector. If a leak is detected, an emission factor is applied as if the leak were occurring throughput the entire reporting year. In order to encourage leak repairs by operators and to minimize GHG emissions, IPAMS requests that EPA provide an optional alterative to annual leak detection surveys that would allow reporters to conduct multiple surveys, as frequently as they deem appropriate. Accordingly, as discussed on page 18623 of the preamble, emissions would reflect leak reductions as determined by repairs and follow-up detection surveys.

To account for fugitive emissions reduction measures that the industry has undertaken in the last few years since the leaker emission factors were developed, IPAMS requests that EPA provide a provision in the final rule that allows leaker emission factors to be updated periodically, either by EPA or by industry in consultation with EPA. As EPA stated on page 18622 of the preamble, the proposed emissions factors will remain constant indefinitely until new factors are provided.

Response: EPA agrees with the commenter and will allow multiple leak surveys; please see the response to EPA-HQ-OAR-2009-0923-1014-9. Concerning the application of updated emissions factors, please see the response to EPA-HQ-OAR-2009-0923-1299-5.

Comment Number: EPA-HQ-OAR-2009-0923-1151-86
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Paragraph 98.233(q)(5) should be revised from “LNG storage facilities . . . . connectors; and other.” to “LNG storage facilities . . . connectors; and other fugitive sources.”

Paragraph 98.233(q)(6) should be revised from "LNG imports and export facilities . . . . connectors; and other." to "LNG imports and export facilities . . . connectors; and other fugitive sources."

Response: EPA disagrees with the American Petroleum Institutes suggested amendments to the rule text under Calculating GHG emissions – Leak detection and leaker emission factors. “Other” is a specific equipment type (i.e. equipment type other than connectors, pumps, or valves) and is associated with an emission factor.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-5
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
Second, the proposal for leak detection and reporting would impose significant additional costs and overstate the actual level of emissions. The proposed rule would require utilities to conduct annual leak detection at above grade M&R stations – that's metering and regulating – and to apply emission factors to those leaking sources. While current practices require regular leak detection, the current level of detection does not nearly approach what would be required by this proposal which calls for optical imaging. We question whether there would be enough equipment or trained operators to conduct such annual surveys at all the M&R stations across the country that would be affected.

Response: EPA disagrees with the comment regarding cost; please see response to comment EPA-HQ-OAR-2009-0923-0049-7. In today's final rule, EPA does not require leak detection at all meters and regulators at city gate stations; please refer to EPA-HQ-OAR-2009-0923-1065-4. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923), "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements." EPA allows additional leak detection techniques; please see Section II, Petroleum and Natural Gas Systems, of the preamble for further details. Concerning the availability of equipment or trained operators, EPA has allowed application for the use of best available monitoring methods; please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1299-11
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:
EPA has not shown that LNG facilities emit significant levels of greenhouse gases from fugitive sources. If a leak were to develop in an LNG facility in a cooldown process, the equipment would be adjusted (e.g., tightening the flange) or the process would be stopped. If a safety relief valve were to fail its annual test by failing to lift properly or failing to reseat, it would be immediately replaced or repaired. If a water heater for a heat exchanger were to register the presence of flammable gas in the water, indicating a small internal leak in a heat exchanger, the heat exchanger would be identified and removed from service for testing and repair or replacement. Leaks in LNG facilities are attended to promptly; leaker factors that presume that leaks continue for 365 days give no recognition to the diligent operating and maintenance practices required in, and common to, LNG facilities. Even if a facility were to count all possible valves, pumps, connections, and other emission sources, and assume that all were detected leaking, even applying the 365-day factors still would not yield a mass of emissions that approached a reportable level. Indeed, facilities that have surveyed their plants as proposed have identified emissions sources numbering in the single digits, an effort yielding a near-infinite cost for the debatable benefit of identifying those tiny masses of emissions. It is likely EPA's unfamiliarity with LNG facilities that has led to its proposed requirement of plant-wide fugitive

detection surveys every year.

Response: EPA disagrees with the commenter on LNG facilities. LNG facilities handle natural gas and hence are liable to equipment leaks just like in other natural gas handling facilities. EPA's criteria for selecting segments and emission sources are outlined in the Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027) under Selection of emissions sources for reporting. Data that is gathered through the Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas Systems will be beneficial to inform future policy. EPA agrees that there is a lack of methane emissions data from LNG facilities, which further necessitates collection of these data in order for EPA to consider possible policy options. As a result, EPA has retained the requirements for reporting from LNG facilities.
EPA agrees with the commenter's point about improving the accuracy of emissions estimates to account for leak repairs and is allowing multiple leak detection surveys to address this. Please see the response to EPA-HQ-OAR-2009-0923-1014-9. In addition, EPA will evaluate the LNG facility data received through the MRR, which are based on emission factors and methodologies in subpart W. EPA will also evaluate other emission factors that EPA may receive. EPA may also consider using direct measurement of equipment leaks and vents if EPA deems the LNG facility emissions data received through the MRR is insufficient to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-1299-9
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:
Subpart W proposes that LNG facilities quantify certain specified process emissions, grouped as defined into vented and fugitive categories. The facility is to measure emissions from certain vented sources. Additionally, the EPA proposes that each facility identify 100% of its fugitive emissions sources by examining all facility equipment with a prescribed detection instrument, and prescribes leaker factors to estimate emissions from these identified sources. The EPA also prescribes a population leaker factor for vapor recovery compressors; this type of plant system at LNG facilities may take several forms, some of which are closed systems with no possibility of leaks.

The EPA has chosen to apply these factors uniformly to generic equipment names across the entire supply chain of petroleum and natural gas systems. However, given the extreme operating conditions in LNG facilities, equipment is designed, selected, installed, operated, and maintained to greatly reduce or eliminate leakage. The factors prescribed, which were introduced in 1993 for the synthetic organic chemical manufacturing industry (SOCMI), have not specifically been evaluated by the EPA for their applicability to current LNG facilities and equipment, nor for their applicability for cryogenic service. Further, the EPA has overlooked the basic principle that underlies the strong safety record of LNG facilities - to design, install, operate, and monitor the facility to keep the product safely within the process equipment. This principle dovetails with EPA's charge to minimize greenhouse gas emissions from that equipment in these facilities. (It is also in LNG facilities' commercial interest to minimize emissions, as the LNG, a premium fuel, as liquid or gas, is the facilities' only product, and it must be dispatched from the plant to customers in order to generate revenue.)

Response: EPA is aware of different technologies for vapor recovery compressors deployed by industry across several sectors to reduce emissions, including the use of closed systems. If this commenter is using low emission technologies as in a closed system, then EPA would expect to see such emissions reflected in its submitted report. However, the use of low emission technology is not known to be ubiquitous in the LNG industry; therefore, the collection of GHG data from the LNG sector is important in understanding emissions from this sector to inform future policy. As regards the prescription of SOCMI factors for applicability to LNG facilities and equipment, in the absence of LNG-specific leak data, EPA sought a comparable factor that would reduce burden on the industry while still capturing emissions information. Based on expert judgment that they were the best publicly available factors, the SOCMI leaker factors for components in NGL service were used to estimate LNG; however, the factors were adjusted for the mass of methane. Please see the response to EPA-HQ-OAR-2009-0923-1299-11. Please also see EPA's Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027) for EPA's method for including LNG facilities in the rule.

Comment Number: EPA-HQ-OAR-2009-0923-1016-40
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
EPA Should Revise and Clarify Several Provisions for LNG Import Terminals (and for LNG Storage Facilities If EPA Does Not Exclude Them)
EPA Should Not Apply "Leaker" Emission Factors at LNG Facilities Because Leaks Are Rare and Fixed Immediately

With respect to proposed emission leaker factors, the EPA assumes that if a fugitive emission source is detected, the source must have continued to leak for all 365 days of the year. This hypothetical assumption would vastly overstate emissions and would not yield useful data for policy development. Leaks are rare at LNG facilities. They are located and all but the smallest are fixed as soon as they occur. As an example, a member recently performed a complete survey of all of the equipment, and piping systems at their LNG storage facility using the FLIR camera. The member only found one small leak at a rod packing on the refrigeration compressor where mechanics were working, as was expected. These facilities are very tight by design and operation. LNG facilities cannot and do not permit conditions such as LNG valve leakage to continue after detection. Detection of leaks is rapid due to installed gas detection and physical facility inspections by qualified operating staff. When leaks are detected, they are generally corrected immediately. Thus, using a "leaker" emission factor that assumes the leak continues all year would seriously overstate fugitive emissions at an LNG storage facility or import terminal.

Response: EPA disagrees with the comment to not quantify LNG facility equipment leaks. Please see the response to EPA-HQ-OAR-2009-0923-1299-11. EPA will allow multiple leak detection surveys; please see the response to EPA-HQ-OAR-2009-0923-1014-9.

Comment Number: EPA-HQ-OAR-2009-0923-1016-42
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
LNG Valves and Minimal Valve Leakage.
Due to the combined conditions of extreme temperature and pressure, valves (gate, ball, butterfly, etc) in LNG service are typically designed with extended bonnets and utilize multiple rings of V-ring style stem packing, made typically of PTFE (Teflon). This style of packing is very resilient and has high sealing qualities, thereby greatly minimizing if not eliminating fugitive emissions. Furthermore, since valves in LNG or natural gas service can range from ¼" to 24" or greater diameter; the use of a required single leaker factor appears arbitrary.

Response: EPA has reviewed this comment and disagrees. EPA's decision to include LNG storage facilities was based on several considerations. First, please see EPA's Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027) for EPA's method for including LNG storage in the rule. In addition, EPA is aware of different technologies for valves deployed by industry across several sectors to reduce emissions. If this commenter is using low emission technologies, then EPA would expect to see such emissions reflected in their submitted report. However, the use of low emission technology does not eliminate the need for LNG storage facilities to report; as such information may demonstrate differentiated emissions levels, which would inform future policy. EPA disagrees with the comment stating that the choice of a leaker factor was arbitrary, as EPA used the best publicly available emission factors.

Comment Number: EPA-HQ-OAR-2009-0923-3541-3
Organization: Sempra LNG
Commenter: David M. Cobb

Comment Excerpt Text:
Table W-6 identifies a single emissions factor for valves. Due to the combined conditions of extreme temperature and pressure, valves (gate, ball, butterfly, etc) in LNG service are typically designed with extended bonnets and utilize multiple rings of V-ring style stem packing, made typically of PTFE (Teflon). This style of packing is very resilient and has high sealing qualities, thereby greatly minimizing if not eliminating fugitive emissions. Furthermore, valves in LNG or natural gas service can range from 1/4" to 24" or greater diameter. The use of a single factor appears arbitrary and may result in a significant overstatement of fugitive emissions for LNG facilities.

Response: EPA disagrees with the comment on the use of a single emissions factor. Please see the response to EPA-HQ-OAR-2009-0923-1016-42.

Comment Number: EPA-HQ-OAR-2009-0923-1025-4
Organization: Paiute Pipeline Company
Commenter: Jeff Maples

<u>Comment Excerpt Text:</u>
<u>LNG Valves and Minimal Valve Leakage</u>
Due to the combined conditions of temperature and pressure, valves (gate, ball, butterfly, etc.) in LNG service are typically designed with extended bonnets and utilize multiple rings of V-ring style stem packing, made typically of PTFE (Teflon). This style of packing is very resilient and has high sealing qualities, thereby greatly minimizing if not eliminating fugitive emissions. Furthermore, since valves in LNG or natural gas service can range from 1/4" to 24" or greater diameter; the use of a required single leaker factor appears arbitrary.

Response: EPA disagrees with the comment on the use of emission factors. Please see the response to EPA-HQ-OAR-2009-0923-1016-42.

Comment Number: EPA-HQ-OAR-2009-0923-1025-5
Organization: Paiute Pipeline Company
Commenter: Jeff Maples

<u>Comment Excerpt Text:</u>
LNG Safety Relief Devices
Due to extreme operating conditions, the majority of safety relief valves in LNG service are soft seated style valves, again this greatly minimizes, if not eliminates, leakage at pressures below the valve opening set point. Additionally, relief valves in the LNG industry in the U.S. are maintained at a very high level of performance, as each relief valve is required by the federal LNG code, 49 CFR § 193.2619, to be inspected and tested annually for lift pressure and positive reseating, which indicates that it operates properly and is not leaking. PHMSA inspects safety valve testing records to confirm that the facility's annual testing of valves has met the regulatory requirements for test frequency and valve performance.

Response: Please see the response to EPA-HQ-OAR-2009-0923-1016-42. EPA is not excluding LNG facilities from reporting in today's final rule because they are regulated by the PHMSA. Please see the response to EPA-HQ-OAR-2009-0923-1299-11 and see the rulemaking docket (EPA-HQ-OAR-2009-0923), "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements."

Comment Number: EPA-HQ-OAR-2009-0923-1016-43
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
LNG Safety Relief Devices.
Due to extreme operating conditions, the majority of safety relief valves in LNG service are soft seated style valves, again to greatly minimize if not eliminate premature leakage at pressures below the valve opening set point. Additionally, relief valves in the LNG industry in the U.S. are maintained at a very high level of performance, as each relief valve at LNG facilities is required by the federal LNG code, 49 C.F.R § 193.2619, to be inspected and tested annually for lift pressure and positive reseating, which indicates that it operates properly and is not leaking. PHMSA inspects safety valve testing records to confirm that the facility's annual testing of valves has met the regulatory requirements for test frequency and valve performance.

Response: Please see the response to EPA-HQ-OAR-2009-0923-1016-42. EPA is not excluding LNG facilities from reporting in today's final rule; please see the response to EPA-HQ-OAR-2009-0923-1299-11. Please see the rulemaking docket (EPA-HQ-OAR-2009-0923), "Understanding the Substance of the DOT Regulations and Comparing Them to the Subpart W Requirements."

13.1.3 ALTERNATIVE OPTIONS TO CONSIDER

Comment Number: EPA-HQ-OAR-2009-0923-0132-3
Organization:
Commenter: Michael Webb

Comment Excerpt Text:
Allowing choice of Emissions Factors or Direct Quantification (§98.233 (q) and §98.233 (r))

EPA previously recognized the importance of allowing the use of either emission factors or Direct Quantification of fugitive emissions.

EPA Document EPA-453/R-95-017, 1995 Protocol for Equipment Leak Emission Estimates, presented four methods for reporting fugitive hydrocarbon emissions. The first three methods used generalized emissions factors based on population counts or leaker counts. The fourth method allowed a facility to quantify leaks to obtain better accuracy in emissions reporting. If you were to allow facilities to quantify leaks, facilities with large leaks would report higher emissions than predicted by Tables W-1 through W-7. Facilities with small leaks would report lower emissions than predicted by Tables W-1 through W-7.

This would have the double advantage of (1) reporting measured emissions for each facility (rather than calculated emissions), and (2) motivating the facilities to fix large leaks, thereby lowering emissions to the environment.

It would also allow companies to become "industry-leaders" through proactive control of fugitive emissions.

A review of the data in my document, which you referenced, will show how and why Direct Quantification will decrease the burden on the environment.

Pages C-1 through C-4 of the report list the individual leak rates of 176 valves in gas service at Gas Processing Plants. The individual leaks are shown in the table below.

Gas Valve Leak Rates in Emission Factors for Oil and Gas Production Operations, January 1995 (scf/hr)

0.00	0.04	0.10	0.27	0.75	2.09	4.89
0.00	0.04	0.10	0.28	0.76	2.16	5.60
0.01	0.04	0.11	0.29	0.83	2.17	5.77
0.01	0.04	0.11	0.30	0.83	2.20	5.98
0.01	0.05	0.11	0.31	0.83	2.30	6.89
0.01	0.05	0.12	0.31	0.84	2.36	7.22
0.01	0.06	0.12	0.32	0.86	2.38	7.25
0.01	0.06	0.12	0.34	0.94	2.39	8.00
0.01	0.06	0.12	0.36	0.96	2.54	10.58
0.02	0.06	0.13	0.37	1.02	2.66	11.91
0.02	0.06	0.13	0.42	1.10	2.73	12.17
0.02	0.06	0.14	0.43	1.14	2.80	13.44
0.02	0.07	0.15	0.47	1.25	2.88	13.71
0.02	0.07	0.15	0.47	1.33	3.02	13.99
0.02	0.07	0.15	0.48	1.43	3.22	14.99
0.03	0.07	0.15	0.48	1.50	3.38	16.40
0.03	0.08	0.16	0.53	1.51	3.49	39.10
0.03	0.08	0.17	0.53	1.51	3.53	44.27
0.03	0.08	0.18	0.60	1.59	3.63	44.31
0.03	0.08	0.19	0.62	1.59	3.79	121.99
0.03	0.09	0.21	0.68	1.62	3.86	
0.03	0.09	0.22	0.68	1.65	4.17	
0.03	0.09	0.24	0.69	1.66	4.38	
0.03	0.09	0.24	0.71	1.67	4.67	
0.04	0.09	0.25	0.72	1.71	4.69	
0.04	0.10	0.25	0.74	1.72	4.69	

As can be seen, most of the leaks are small (less than 1.00 scf/hr) and a few are large (greater than 10.00 scf/hr). This population pattern is typical of all leak data sets, regardless of facility type, component type, stream composition or pressure.

Total emissions from the 176 valves are 542 scf/hr. The largest leak (121.99 scf/hr) is 23% of that total. If a facility were to repair that single valve, the burden on the environment would be reduced by 23%. Repairing the 10 largest leaks would reduce the burden by 62%.

Using Direct Quantification to prioritize maintenance work is essential to controlling fugitive emissions and documenting their reduction.

For this reason, I recommend allowing facilities to make Direct Quantification of the leaks if

they so choose.
The proposed Subpart W already mandates Direct Quantification for Reciprocating Compressor Rod Packing Venting (§98.233 (p) (3) (ii)); I am suggesting that Direct Quantification be included as an option for all facilities in §98.230.

Response: EPA disagrees that it should provide an option for reporters to submit measured data for equipment leak emissions. In the April 2009 proposed rule, EPA required reporters to measure their equipment leaks; however, many potential reporters commented that the cost burden was too high. EPA accepted these comments and revised the rule to include population emission factors and leaker factors to reduce compliance burden on industry while maintaining the necessary quality of data to inform policy. Please see Section III of the preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) and response to comment EPA-HQ-OAR-2009-0923-1155-12.

Comment Number: EPA-HQ-OAR-2009-0923-0132-1
Organization:
Commenter: Michael Webb

<u>Comment Excerpt Text:</u>
In §98.233 (q) and §98.233 (r), allow affected facilities the choice of either calculating fugitive emissions using Emissions Factors or measuring fugitive emissions using Direct Quantification

Response: EPA disagrees that it should provide an option for direct measurement as an alternative to monitoring equipment leaks; please see the response to EPA-HQ-OAR-2009-0923-0132-3.

Comment Number: EPA-HQ-OAR-2009-0923-1037-1
Organization: ENVIROTECH ENGINEERING
Commenter: Terence Trefiak

<u>Comment Excerpt Text:</u>
Using general emission factors can cause significant error in estimating emission rates.
In the example above these two leaking components would be given the same estimated leak rate which could be inaccurate (over estimation or under estimation) by many orders of magnitude.
In our experience the cost of leak measurement is approx. 10% of the total cost of performing a fugitive emission assessment. The majority of the assessment time is used to inspect and detect emissions and the time required to measure leaks is relatively low in comparison, but the value of having the actual leak rate is significant. All of our clients to date have requested leak rate direct measurement as part of the fugitive emission assessments.

We recommend that, if a reporting company has undertaken leak rate measurements as part of a fugitive emission assessment, that the finalized GHG Reporting Rule allows the option for the reporter to use the measured information as opposed to having to use the prescribed generic leakage factors.

Response: EPA disagrees that it should provide an option for direct measurement as an alternative to monitoring equipment leaks. Please see the response to EPA-HQ-OAR-2009-0923-0132-3.

Comment Number: EPA-HQ-OAR-2009-0923-0582-30
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
WCI Recommendations: WCI recommends adoption of USEPA methods 98.233(q) and (r) with minor modifications. While there are methods available that provide quantitative data on fugitive leaks (e.g. use of calibrated sampling bags and/or high-volume sampler) these methods are costly and time consuming. Further more, these quantitative methods provide a single snapshot in time and no information concerning leak duration.

The draft EPA rule quantification methodologies will not produce cap-and-trade quality data because they use default emissions factors rather than actual measurements of emissions. Additionally, these calculation methods assume that the component has been leaking for the entire reporting period and this assumption will overestimate actual emissions.

While the data generated are not cap-and-trade quality, section 98.233(q) does require that reporters conduct an annual component screening (a directed inspection program) on a subset of components. This will provide operators with operable information which both identifies leaking components and provides semi-quantitative data on leak rates. This information will help operators identify and prioritize leak mitigation opportunities.

WCI Modifications: Equations W-18 and W-19 contain errors which should be corrected. In both equations the variable GHGi is set equal to 1 for many sources. GHGi represents the concentration of GHGi (where i = CH_4 and CO_2) in the gas stream in question. Setting GHGi equal to 1 for CO_2 will result in a large overestimation of CO_2 emissions. For CO_2, GHGi should be the concentration of CO2 in the gas stream in question.

Response: Given that the purpose of this rule is to collect data to inform a variety of programs and policies, EPA has determined that the methodological rigor presented in today's final rule is sufficient for these purposes. If and when a particular policy is implemented (e.g., cap and trade), EPA will evaluate whether adjustments to the methodologies in this subpart are warranted. Please see the response to EPA-HQ-OAR-2009-0923-0582-10.
EPA agrees that the rule requirements should provide the option to account for the duration that a component leaks rather than assuming that it leaks for the entire reporting period. However, EPA is not requiring that reporters perform multiple leak surveys each year. Today's final rule allows reporters the option to account for the time a component leaks and provides guidance on how to estimate this based on the number of leak screening surveys that the reporter chooses to conduct.

EPA agrees that in the proposed rule the default fraction of CO_2 for equipment leaks was inaccurate. Today's final rule has been revised and has a more accurate parameter for the CO_2

fraction of emissions using the same method as the "U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2008." For onshore petroleum and natural gas production and onshore natural gas processing, reporters use their own CO_2 concentration from composition analysis. For pipeline quality natural gas in transmission, underground storage, LNG storage, LNG import and export, and distribution, the CO_2 content is 1.1×10^{-2}.

Comment Number: EPA-HQ-OAR-2009-0923-1011-37
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(a) Natural gas pneumatic high bleed device venting

Sections 98.233 (a) and (b) require the use of either manufacturer's data for high bleed pneumatics or the application of an emission factor for low bleed pneumatics. However, identifying the model of a particular device may be difficult if name plates are obscured by paint or wear. Additionally, some units may have been modified over time to reduce their bleed rate, but accurate records of these modifications may not be available.

The EPA should provide a default leak rate that can be used for those devices where the manufacturer or model number is not known. Alternatively, the EPA could allow operators to use appropriate factors from sources such as the API Compendium to obtain factors for these particular devices. As an additional option, the Hi-Flow sampler or similar device could be used to make a measurement of the bleed rate from pneumatic devices. If companies already have this technology in house or are having it contracted for other measurements at their sites, this could provide a method to obtain data that might otherwise be hard to get. The key here is to ensure flexibility in monitoring options.

Response: EPA agrees with the comment regarding the difficulty of identifying pneumatic device manufacturers. Today's final rule has been revised to use a population emission factor for high and low-bleed pneumatic devices, and therefore identifying manufacturers and manufacturer data is no longer necessary. Please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1018-22
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (a): CAPP would like clarity on the following statement in sub-section (2): Who decides what is a "similar device model"? Is this a role the EPA would take on an on-going basis and how would a facility go about receiving a decision on a similar device model?

To reduce the burden associated with collecting data on the number of hours each controller was in operation in the year, CAPP suggests that as a default, companies assume that all controllers in this category are in operation 24 hours per day, 365 days per year. This would provide a conservative estimate of emissions from this source. Those who have or choose to collect actual operating hours would be free to use those data in lieu of the default. This method would then be consistent with 98.233(b).

Where manufacturer specific bleed rate in not available, CAPP also recommends allowing the use of average gas consumption rates for high bleed pneumatic instruments (e.g., CAPP 1993 Table 2-2) and that the EPA may want to consider using generic count based on facility and process equipment type as per CAPP 2005, Volume 5.

Response: EPA agrees and today's final rule has been revised to use a population emission factor for low and high-bleed pneumatic devices. Please see the response to EPA-HQ-OAR-2009-0923-1011-37. Today's final rule has also been revised such that pneumatic devices will report with an assumption of 8,760 operating hours per year. EPA determined that monitoring the operational time for each pneumatic device is overly burdensome; please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1018-3
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
CAPP supports the EPA's decision to provide alternatives to the use of direct measurement, such as engineering estimates, in recognition of the fact that the installation of new meters or emission monitoring equipment often requires a facility shutdown in the oil and gas sector (as in many other industrial sectors). These shutdowns typically only occur on an annual or semi annual basis, making it difficult to ensure compliance without costly unscheduled shutdowns.

Response: EPA agrees and has maintained these provisions in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1019-4
Organization: Red Cedar Gathering
Commenter: Ethan W. Hinkley

Comment Excerpt Text:
Leak Detection Surveys and Annual Calculations

EPA is requesting comments on an alternative approach for fugitive leak detection and reporting. This approach includes requiring a facility to conduct multiple surveys and would take into account any repairs that were conducted between surveys. Red Cedar recommends that EPA allow this alternative approach as an option in the final rule, but does not recommend that it be mandatory. For a facility that makes repairs to reduce fugitive emissions this option would allow credit to be given for those repairs. By making it an optional approach, facilities that do not make repairs, likely due to few leaking components, would not be burdened with multiple surveys that would likely show very similar results.

Response: EPA agrees and has revised today's final rule to allow reporters the option to perform multiple leak surveys and repair discovered equipment leaks, and account for those repairs in their reported emissions. Please see the response to EPA-HQ-OAR-2009-0923-1015-39.

Comment Number: EPA-HQ-OAR-2009-0923-1076-1
Organization: GDF SUEZ Gas NA LLC
Commenter: Francis J. Katulak

Comment Excerpt Text:
In summary, the extensive requirements of existing federal LNG regulations, the robust equipment designed and selected for LNG facilities, the principles and practices developed by the LNG industry and by individual LNG facilities, and the regular inspections and evaluations by federal inspectors all support the efforts of facility personnel to ensure that LNG facilities are operated and maintained to keep the LNG safely within the process equipment. As a result, fugitive emissions of greenhouse gases are likewise nearly eliminated. Therefore, EPA's proposal to require a burdensome optical detection survey to attempt to detect fugitive leaks in an LNG facility cannot be justified, due to the high cost and the insignificant findings that would result from using EPA's methodology. And it is inappropriate to compute emissions based on assumed 365-day leaks, to apply factors that relate to equipment (and possibly fluids) distinct from those in LNG facilities, and to use an instrument for detection that has not been shown to provide accurate identification of emissions sources (and which is so specific as to be sure to be superseded in the future, necessitating a change to the regulation), rather than allowing those facilities where a fugitive emissions survey is appropriate to select from multiple approved detection methods to identify active emission sources.

Response: EPA disagrees, and will continue to retain reporting requirements from LNG facilities. Please see response to comment EPA-HQ-OAR-2009-0923-1025-1.
EPA disagrees that optical gas imaging instruments will be unable to detect methane leaks from LNG equipment and that the fluid properties governing the ability of a substance to leak through an orifice will differ substantially between LNG and NGLs such that the emission factors cannot be used to scope emissions with the intention to inform future policy. In the absence of LNG-specific leak data, EPA sought a comparable factor that would reduce burden on the industry while still capturing emissions information. Based on expert judgment, the SOCMI leaker factors for components in NGL service were used to estimate LNG; however, the factors were adjusted for the mass of methane.

EPA also must collect data from the LNG sector in order to inform possible future policy. The information on emissions from the LNG sector are necessary for EPA to evaluate the source and its level of emissions to determine what, if any, action is appropriate to take regarding those emissions. Furthermore, as explained in Section II.H of the preamble for the 2009 final Mandatory Reporting of Greenhouse Gases and 40 CFR 98.2(i), if a reporters emissions are below 15,000 mt CO2e for three years in a row or below 25,000 mt CO2e for five years in a row they can cease reporting.

Comment Number: EPA-HQ-OAR-2009-0923-1151-76
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
(Preamble pp. 79-80) The API compendium emissions factors that we are proposing to use in the upstream oil and gas production sector may be underestimating emissions. EPA seeks comment on how to improve these factors and/or collect more accurate data.

API supports the use of emission factors from the API Compendium, as these are widely used and accepted by the oil and natural gas industry worldwide. In addition, Subpart W should provide for the use of new emission factors as they develop. As such, API recommends removing Tables W-1 through W-7 from the reporting rule and instead reference a technical document of emission factors that is more readily updated.

Section VIII of this document details a comparison between the emission factors proposed for Subpart W and the API Compendium. Errors and recommendations for specific emission sources are noted there. For many source types, the API Compendium emission factors are larger or equivalent to those proposed by EPA.

Response: EPA disagrees with only using emission factors from the API Compendium; please refer to EPA-HQ-OAR-2009-0923-3524-4 for further details. EPA will not remove the emission factors from subpart W and place them in another reference technical document, as this will not reduce the amount of time needed to reference updated factors as compared to having the factors remain in the rule itself.

Comment Number: EPA-HQ-OAR-2009-0923-1041-3
Organization: Spectra Energy Corp
Commenter: Brianne Metzger-Doran

Comment Excerpt Text:
Vent Measurement for Manifold Vent Lines on a Continuous Basis Should be Allowed as an Operator Option

Continuous measurement of manifolded vent lines and aggregate annual emissions reporting should be allowed, at the operator's discretion, as an approved alternative to the methods defined in § 98.233. This continuous aggregate reporting option, supported by INGAA, is of particular importance to Spectra Energy because Spectra Energy has—at substantial cost and at a substantial number of its facilities—installed manifolded vent lines capable of supporting reliable continuous emissions measurement devices. These manifolded vent lines, or common headers, were installed to satisfy the "source control" requirements of the 1989 PCB consent decree between the United States and Texas Eastern Transmission Corporation. These common headers provide substantial environmental benefit and allow Spectra Energy to continue its PCB source control activities by directing the vented streams to liquid separators prior to venting to the atmosphere. As currently contemplated by § 98.233, the Proposed Rule would require the measurement of each covered emissions source connected to the common header, which could in some cases require Spectra Energy to physically dismantle the manifolded vent line system at least once every year to safely obtain "snapshot" emission measurements. If continuous measurement of manifolded vent lines and aggregate annual emissions reporting is allowed as an operator option, Spectra Energy, and operators like Spectra Energy, will be able to safely collect and report to EPA continuously measured reliable data. This data set will also allow EPA to compare these results with the GHG emissions data reported by operators that take a "snapshot" measurement of emissions from individual vents or pieces of equipment.

Response: EPA disagrees with the comment that compressor venting should be allowed to conduct direct measurement of common manifolded vent lines. The rule allows installation of a port on each vent line to the manifold, for insertion of a temporary meter, and these ports can be installed at ground level. Typically, compressor venting emissions vary with the mode of operation of the compressor. The emissions are highest when the compressor is operating and lower when they are in the not operating depressurized mode. However, when the compressor is not operating depressurized, there may be leakage of natural gas through the unit isolation valve, particularly if the valve seat has become fouled and will not completely close. Hence, to correctly characterize annual emissions from compressors, estimation of emissions in different compressor modes is required. A temporary meter such as a vane anemometer or permanent meter such as an orifice meter can be used to measure emissions from the vents.

Comment Number: EPA-HQ-OAR-2009-0923-1156-13
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
Further, it is strongly recommended that EPA approve alternate methods of determining and reporting fugitive emissions on reciprocating compressor rod packings other than direct measurement, such as manufacturer specifications, engineering calculations, or industry benchmark values for comparable engines. This will remove the financial burden associated with conducting leak testing on every reciprocating compressor rod packing nationwide. For one facility with six compressors having a total of eighteen compression cylinder rod packings, we have received an estimate of $40,000 to $60,000 per year to conduct the prescribed annual sampling. Obviously, the testing can be done, but the result of this sampling is of little value because it only captures fugitive emissions, if any, at one point in time, since any leaking rod packings are promptly addressed as part of the routine maintenance of these units.

Response: EPA has determined that commenters' incorrect assumptions and misinterpretations of the proposed rule largely account for the discrepancy in compressor monitoring cost burden estimated by EPA. The rule does not require that vent manifolds be broken apart. The rule allows installation of a port on each vent line to the manifold, for insertion of a temporary meter, and these ports can be installed at ground level. For more information, please see the response to EPA-HQ-OAR-2009-0923-1099-18. Further, the sampling is not of little value. EPA disagrees with the commenter that leaking rod packings are promptly addressed. On the contrary, EPA has learned that rod packing emissions varies greatly depending on the compressor itself and the wear that a specific compressor may have on rod packing. Also, compressor maintenance is most often done at fixed time intervals, not based on the wear of the rod-packing which impacts emissions rates and creates substantial inconsistencies in emissions from this source.

Comment Number: EPA-HQ-OAR-2009-0923-1206-47
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
Second, while GPA supports the full use of the API Compendium to calculate GHG emissions for all sources covered by the proposed Subpart W, at a minimum we suggest the application of the API Compendium in place of any direct measurement methods. For the gas gathering and processing sector, direct measurement is generally proposed to be limited to compressor wet seal vents and rod packing venting. The current proposal potentially requires direct measurement of compressor rod packing vents from every cylinder of a compressor in cases where the vent lines are not tied to a common line, which is a common practice in gathering compression facilities and production facilities. The prescribed methods for these sources are flawed because they assume a snapshot measurement applied across an entire year is more accurate than an emission factor based on well documented and controlled studies.

Response: EPA disagrees that the API Compendium is suitable for all sources covered by subpart W for the intent of informing future policy. Please see the response to EPA-HQ-OAR-2009-0923-3524-4.

With regard to monitoring of gathering and boosting emissions, today's final rule no longer requires reporting of those sources; please see Section II.F of the preamble to today's final rule for the response to this comment.

EPA disagrees that direct measurement of emissions from compressor venting is less accurate than emission factors. With regard to centrifugal compressor wet seals, please see the response to EPA-HQ-OAR-2009-0923-1206-45. With regard to reciprocating compressor rod packing, commenters made incorrect assumptions about measuring manifolded vents. The rule does not require that vent manifolds be broken apart. The rule allows installation of a port on each vent line to the manifold, for insertion of a temporary meter, and these ports can be installed at ground level. For more information, please see the response to EPA-HQ-OAR-2009-0923-1099-18.

Comment Number: EPA-HQ-OAR-2009-0923-2869-1
Organization:
Commenter: Matt Harrison

<u>Comment Excerpt Text:</u>
Please allow the use of emission factors for compressor related components. EPA should not require direct measurements for all gas compressors. As the project manager of the GRI/EPA studies from the 1990's that are cited in the proposed rule, I am familiar with many of these emission measurements. The direct compressor measurements EPA is requiring for five fugitive

and vented components at compressor stations are more technical, complex, and expensive to measure than EPA has estimated. Some emission sources are not possible to individually measure without physical modifications to the site. EPA should continue to fund research that refines the key natural gas emission factors. EPA should not require the entire industry to make measurements for a GHG reporting rule. EPA could allow for direct measurement as an alternative to emission factors, if the reporter elects, in their sole discretion.
Please allow for the use of scaled emission factors, rather than more detailed modeling that the proposed rule requires for sources like glycol dehydrators, amine units, and tanks. For the reporting rule purposes, the accuracy of scaled emission factors should be acceptable.

Response: EPA disagrees that direct measurement of emissions from compressor venting should be replaced by emission factors. With regard to centrifugal compressor wet seals, please see the response to EPA-HQ-OAR-2009-0923-1206-45. With regard to reciprocating compressor rod packing, please see the response to EPA-HQ-OAR-2009-0923-1099-18. The rule does not require that vent manifolds be broken apart. The rule allows installation of a port on each vent line to the manifold, for insertion of a temporary meter, and these ports can be installed at ground level.

EPA disagrees that scaled emission factors should be used for glycol dehydrator, amine units, and storage tank emissions. With regard to storage tanks, EPA designated it as a source with large uncertainty using typical emission factors, as discussed in Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document (EPA-HQ-OAR-2009-0923). With regard to acid gas removal vent, please see response to comment EPA-HQ-OAR-2009-0923-1024-26. With regard to glycol dehydrators, EPA determined that reporters will obtain better emissions estimates from larger glycol dehydrators using simulations versus emission factors, and without a substantial increase in cost burden. Once the initial set up for the software is accomplished, it takes little time to make multiple runs with new inputs. However, for small dehydrators less than 0.4 million cubic feet per day throughput, and storage tanks with separator or wellhead production throughputs less than 10 barrels per day, EPA agrees that simulations are an unnecessary burden for the magnitude of emissions, and has revised the rule to provide default emission factors that may be used. Please see “Equipment Threshold for Dehydrators” and “Equipment Threshold for Tanks” in the rulemaking docket (EPA-HQ-OAR-2009-0923) and Section II.E of the preamble to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1167-30
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

<u>Comment Excerpt Text:</u>
For small emission sources, the use of industry standard emission factors. For example:
For glycol dehydrators with throughput less than 3 MMcf/day, appropriate (i.e. considering use of flash separator and gas-assisted glycol pumps) emission factors from the API Compendium would be used rather than collect all the data and samples required for a GLYCalc estimation. While the emission factor approach may not be accurate for some individual sources, for the

population of sources errors average out and the emission factor estimates would provide quality data to inform policy decisions.

Response: EPA agrees that small glycol dehydrators may use emission factors to estimate emissions. Please see “Equipment Threshold for Dehydrators” in the rulemaking docket (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-3524-4
Organization: Chesapeake Energy Corporation
Commenter: Grover Campbell

<u>Comment Excerpt Text:</u>
Less Direct Measurement Should be Required.
Although EPA has reduced some direct measurement requirements from those included in its April 2009 MRR Subpart W proposal, EPA's current proposal does not acknowledge longstanding and accepted international protocols adopted by other countries to calculate emissions from the oil and gas sector. These protocols include Australia's National Greenhouse and Energy Reporting System ("NGERS"), the European Union Emission Trading Scheme ("EU ETS"), and Alberta's Greenhouse Gas Reporting Program, which all either allow or require reporting emissions calculated using the Compendium.[191] EPA's proposal assumes that calculating and reporting emissions from each small component related to oil and gas production will result in a more accurate GHG inventory, rather than using carefully documented emissions factors applied across entire facilities. However, utilizing burdensome methods of direct measurement will not necessarily result in an emissions inventory of greater value or validity, as compared to using other accepted and proven techniques, such as the Compendium. In fact, the CO2 emissions estimated from onshore facilities using the Compendium have been shown to be comparable to other available methods.[192] Moreover, if all of industry were to use the Compendium, the uncertainty in the values reported would be more uniform across the reporting industry, whereas if direct measurement were used, the uncertainties would be non-uniform across the reporting industry. Uncertainties can arise when using models or equations, but these errors can be eliminated in advance through the proper application of methods to the source

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[191] Australian Government, Department of Climate Change, Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia, ch. 3 (June 2009); Answers to Frequently Asked Questions on Greenhouse Gas Emissions Monitoring and Reporting under the EU Emissions Trading System Pursuant Directive 2003/87/EC, at 13 (Sept. 2007); Government of Alberta, Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications, at 30 (Feb. 2010).

[192] NARSTO Emission Inventory Workshop, Development of the API Compendium for Estimating Greenhouse Gas Emissions (Oct . 2003) , available at _http://nas .carer.uiowa.edu/ICARTT/Seminars%20and%20Formal%20Presentations/NARS"TO Emissions workshop 2003/presentations/ritter .pdf (comparing the Compendium to the following other methods: Exploration and Production Forum, Methods for Estimating Atmospheric Emissions from E&P Operations (E&P Forum 1994); Intergovernmental Panel on Climate Change, Guidelines for National Greenhouse Gas Inventories (IPCC 1997; UNECE/EMEP 1999; IPCC 2001); Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean, Atmospheric Emissions Inventories Methodologies in the Petroleum Industry (ARPEL 1998); World Resources Institute and World Business Council for Sustainable Development, The Greenhouse Gas Protocol ffRI/WBCSD 2001)).

category. LEVON Group, Addressing Uncertainty in Oil and Natural Gas Industry Greenhouse Gas Uncertainties, at 2-1 to 2-2 (Sept. 2009).[193] In contrast, "the nature of the measurement process. . . makes it impossible to measure a physical quantity without error." Id. at 2-2. Errors may originate from "sampling, measuring, incomplete reference data, or inconclusive expert judgment." Id. at 2-2. Thus, "determining the true value of any measured variable is not practical due to the limitations of measurement equipment and procedures, and the possibility of human error." Id at 3-1 . Therefore, by having sources use the Compendium, the uncertainty of the results reported should be uniform and the accuracy and overall reliability of the data should increase, at a fraction of the cost.

Response: EPA disagrees that applying API Compendium emission factors across the industry would result in more accurate emissions estimates than the methods in today's final rule. The emission factors in the US Inventory, and also in the API Compendium, have been demonstrated to underestimate emissions by an order of magnitude or more for sources including gas well liquids unloading, gas well completions and workovers, and centrifugal compressor wet seal degassing vents. EPA discusses the methodologies it considered and its goals in the Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1206-45
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
As explained in Section 6, above, the rule should allow for the use of API Compendium factors to estimate emissions from centrifugal compressor wet seal degassing vents.
Response: EPA has reviewed this comment and disagrees with this comment. Please see response to comment EPA-HQ-OAR-2009-0923-3524-4.

Comment Number: EPA-HQ-OAR-2009-0923-1005-9
Organization: Independent Petroleum Association of America
Commenter: Lee Fuller

<u>Comment Excerpt Text:</u>
As we stated in our 2009 comments, there are clearly emissions estimating tools available that have been used and can be improved without imposing these new requirements. If better estimates are needed for this small portion of the GHG inventory, EPA can turn to its own capabilities to address these estimates. EPA operates the Natural Gas Star program. It cites information in supporting documents to the 2009 proposal indicating that Natural Gas Star has identified and to some degree determined what emissions areas at production systems generate the most emissions. Similarly, API released a new version of its Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry. These tools can be used

[193] Prepared for the International Petroleum Industry Environmental Conservation Association ("IPIECA"), API, and Concawe.

to create reasonable average emissions projections for production systems that could be linked to production volumes. And, EPA could then improve its GHG estimates for onshore petroleum and natural gas production without imposing the costly reporting burdens that would result from inclusion of these operations in the reporting requirements.

Response: EPA has reviewed this comment and disagrees with applying API Compendium emission factors across the industry. Please see response to comment EPA-HQ-OAR-2009-0923-3524-4. The API Compendium methods underestimate emissions substantially for sources such as gas well liquids unloading, gas well completions and workovers, and centrifugal compressor wet seal degassing vents. Therefore, it is necessary to gather actual emissions data from these and other sources such that EPA can meet data quality standards necessary to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-1197-7
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

Comment Excerpt Text:
Provide alternative to optical gas imaging instrument - Limiting leak identification to only an optical gas imaging instrument is too restrictive and would result in increased cost and will worsen the shortage of qualified personnel to conduct leak detection. Options should be offered to use alternative methodologies that are available, currently are in practice, and provide better or equivalent results in most cases.

Response: EPA agrees that alternatives to optical gas imaging may be used for leak detection for accessible components. Please see the response in Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1167-8
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
In addition to removal of unnecessary emission sources, Nobles recommends that the Proposed Rule revisions to reduce burden while collecting GHG emissions data to develop a representative inventory include alternative, simpler, streamlined GHG emission estimation methods: Representative sampling and measurements to develop emission factors / data to estimate entire population emissions rather than test or sample every emission source

Response: EPA compared alternative monitoring methodologies to determine which sources require direct measurement or leak detection and if a representative sample would result in reduced burden on industry while maintaining the necessary quality of data to inform policy. EPA determined that direct measurement of representative samples was appropriate for gas well venting during well completions or workovers with hydraulic fracturing, centrifugal compressors wet seal degassing venting, and reciprocating compressor rod packing venting. EPA also determined that leak detection of representative samples was appropriate for above-ground meters and regulators at non-custody transfer city gate stations.

Comment Number: EPA-HQ-OAR-2009-0923-1042-14
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§ 98.233 Calculating GHGs emissions.

ConocoPhillips General Comment:

We request EPA add an option that applies to all sources that gives the reporter the ability to submit to EPA a request for a waiver from the prescribed calculation methodology for a particular source. The waiver request can require the reporter to justify an alternative calculating methodology. This will allow for circumstances where an alternative method is more accurate for GHG emission calculations while also reducing the data collection/reporting burden. In addition, the approved methodology will be documented in the GHG Monitoring Plan.

Response: EPA disagrees that reporters should have the ability to request a waiver from the required calculation methodology for a particular source. EPA selected the monitoring methodologies that would minimize burden on industry while maintaining the necessary quality and consistency of data to inform policy. Additionally, we have provided flexibility by introducing simplified methods and best available monitoring methods. Please refer to Section II.E and II.F of the preamble to today's final rule. Based on the changes made, we have concluded that it is not reasonable to review and regulate customized, individual requests for each source from each reporter. Furthermore, to ensure data consistency and quality, it is necessary to have all reporters following the same methodologies for the same emission sources.

13.2 GREENHOUSE GAS CALCULATION PROCEDURES

Comment Number: EMAIL-0002-4 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
Screening Criteria and Levels are Necessary to Establish the Requirement to Report under Subpart W.

Based on the currently proposed calculation methods in Subpart W, emissions from many of the GHG sources are unpredictable, which will make determining applicability relative to the 25kTon/yr threshold impractical. In particular, emissions from the following sources cannot be predicted: blowdowns, flares, compressor vents & seal, and fugitive leaks. Due to the unpredictable nature of these sources, a facility will not be able to establish applicability to Subpart W reporting until well into a calendar year and perhaps not until the end of a calendar . Also, for compressor vents & seals and fugitive leaks, a facility will not be able to determine emissions from the sources until the direct detection and measurement is completed. In order for the regulated community to establish applicability of the GHG reporting rule, specifically for Subpart W, screening criteria need to be established that allows this determination to be made with certainty in January of each calendar year.

Response: To assist reporters in determining applicability, EPA plans to provide reporters with a screening tool. Please see Section II.F of the preamble to today's final rule for a response to this comment and further details on the screening tool.

Comment Number: EPA-HQ-OAR-2009-0923-0055 -6
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

Comment Excerpt Text:
Allow leak measurements as an option to determine bleed rates of pneumatic control devices.

Response: EPA has determined that leak measurement to determine the bleed rates of pneumatic control device is too onerous and has chosen not to include it in today's final rule. In today's final rule, all pneumatic device emissions are required to be estimated using emissions factors.

Comment Number: EPA-HQ-OAR-2009-0923-0582-14
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Discussion of measurement options:
1) Engineering Calculations, Metering where available.

There is a paucity of data concerning the accuracy of using engineering estimates to estimate fuel consumption. In addition, there do not appear to be standard methods available for the determination of variables such as engine load factor. For these reasons, WCI feels that engineering approaches to the quantification of fuel consumption are not sufficiently accurate for this important emission source.

2) Metering required for significant fraction of fuel use, remainder by engineering calculations.

Metering of field gas consumption combined with periodic sampling of gas composition is the most accurate and desirable manner to quantify these CO2 combustion emissions. However, because it is likely that most field gas use is not metered, requiring the installation of new meters at all sources may be excessively burdensome, especially considering that these units are often relatively small and geographically dispersed among wellhead. To decrease this burden and yet obtain data that is reasonably accurate in the aggregate, it is appropriate to require metering for only a significant fraction of the total field gas use, and estimate the remainder by engineering calculations.

Two options were considered for setting thresholds that would trigger the metering requirement. Both are based on the rated heat input capacity or horsepower of the combustion equipment and both allow for a phase-in of the metering requirement, with higher thresholds the first year of rule implementation and lower thresholds thereafter.

(a) Metering thresholds based on capacity and device type.

In this approach, the requirement to meter field gas use would be determined at the unit level, with different thresholds depending on the type of device (compressors, heater-treaters, heaters and additional equipment). For all devices below the threshold, fuel consumption could be determined using an engineering approach. The primary disadvantage of this approach is that it discourages common-pipe metering of installations having a large number of small sources.

(b) Metering threshold based on capacity of installation-level field gas combustion equipment. In this approach, the requirement to meter field gas use is based on the installation-level sum of heat input capacity of the field gas combustion units. This approach would tend to encourage common-pipe metering, and could potentially cover more field gas use while requiring meters at fewer installations.

Response: EPA disagrees with the comment. Please see the response to comment EPA-HQ-OAR-2009-0923-0582-17.

Comment Number: EPA-HQ-OAR-2009-0923-0582-17
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
Subpart W should include emissions calculation methodologies and fuel use measurement and analysis requirements specifically designed for the onshore production segment, taking into account the type and size of combustion units, their dispersal among individual wellhead sites, and the common availability of gas composition data obtained for production purposes.

WCI recommends Option 2b listed above. WCI recommends use of the Subpart C Tier 3 calculation method (measured fuel carbon content) but with metering and fuel analysis requirements modified to be more feasible for oil and gas production installations. To ensure that a significant fraction of field gas use is metered, while not requiring the installation of meters at installations with only minor amounts of field gas use, we recommend setting an installation-level threshold for the metering requirement. For the installations falling below the threshold, we recommend that field gas consumption be estimated using an engineering approach such as that given in the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry (2009; page 4-5).

We think that an installation-level threshold is preferable to individual thresholds for each type of combustion equipment (engines, heaters, etc.) because common-pipe metering will be the most practical approach for most operators. We recommend that this threshold be set at a rated fuel use capacity of 525 MBtu/hr for the total of all field gas combustion equipment at an installation. To allow time for installation of all the new meters required, we recommend a phased approach, with the threshold set at 1675 MBtu/hr for the first year that the monitoring rule is in effect. The higher threshold corresponds to about 200 hp and 800 metric tons CO2e/yr, and the lower threshold corresponds to about 62 hp and 250 metric tons CO2e/yr.

For the carbon content values to be used in the calculation methodology, we recommend that field gas composition be determined twice per year. When sufficient data are available to evaluate variation with time for individual wells and across wells within a geological formation, this requirement could potentially be modified to reduce the frequency of analysis or the number of wells per formation that must be analyzed.

Response: EPA considered the points raised above but has determined that the cost of metering fuel gas consumption in onshore production at an equipment type level or installation level results in undue reporting burden. In today's final rule, EPA is including monitoring methods for onshore petroleum and natural gas production that will sufficiently characterize combustion emissions to inform policy while balancing reporting burden. Onshore production portable and stationary combustion must follow the monitoring methods in subpart W. EPA does not agree with the commenter on the composition requirements for onshore production. Please see Section II.E of the preamble to today's final rule for EPA's changes regarding gas composition sampling requirements. Onshore production operations typically know the composition of their produced natural gas (or field gas). The incremental accuracy gained from sampling over existing composition data does not justify the incremental cost burden associated with sampling.

Comment Number: EPA-HQ-OAR-2009-0923-0582-20
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
WCI recommends that the following paragraph be added to SECTION 98.233:

(aa) Field gas combustion. For combustion units that combust field gas, you must comply with following requirements:
(i) Measure the higher heating value of the field gas annually.
(ii) If the measured higher heating value is equal to or greater than 970 Btu/scf and less than 1,100 Btu/scf, then calculate the CO_2, CH_4, and N_2O emissions using the methods in subpart C of this part (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.
(iii) If the measured higher heating value is less than 970 Btu/scf or greater than 1,100 Btu/scf, then calculate the CO_2, CH_4, and N_2O emissions using either the Tier 3 or Tier 4 methodology in subpart C of this part (General Stationary Combustion Sources).
(iv) If the maximum rated heat input capacity of all combustion equipment located at your facility is less than or equal to 1675 MBtu/hour for the first reporting year and less than or equal

to 525 MBtu/hour in all subsequent reporting years, then fuel use may be determined by engineering calculation based on rated heat input capacity or horsepower and load factor.

Response: EPA disagrees with the commenter. See the response to comment EPA-HQ-OAR-2009-0923-0582-17.

Comment Number: EPA-HQ-OAR-2009-0923-1011-36
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233 Calculating GHG emissions

Efforts to reduce lost gas have been a driver for companies to implement component replacement/repair programs. Management of this program requires that pre- and post-leak measurement readings be taken to justify Operation and Maintenance (O&M) costs and confirm fugitive emission reductions. EPA should consider that when additional direct measurements of emissions for any component are available, the operating company could optionally use multiple measurement results obtained during the reporting year to calculate annual emissions for the component surveyed per the company's other reporting procedures for the prioritization of related leak reduction work.

Response: In today's final rule, EPA allows for the adjustment of leak estimates based on multiple surveys. Please see Section II.D of the preamble to today's final rule for further details. EPA disagrees with the commenter on the use of leak measurements to estimate emissions. EPA has determined that providing monitoring methods to conduct leak measurement of a sample of leaking components and applying it to the entire facility is not practical to define in today's final rule or necessary to inform future policy. Furthermore, such requirements would put undue verification burden on EPA. Hence, EPA requires the use of leaker emissions factors when leaks are found.

Comment Number: EPA-HQ-OAR-2009-0923-1011-7
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233 Calculating GHG emissions.—El Paso encourages the EPA to allow annual emissions to be optionally based on all direct measurement results that may be available during a calendar year for any emission source.

Response: Please see EPA's response to comment EPA-HQ-OAR-2009-0923-1011-36.

Comment Number: EPA-HQ-OAR-2009-0923-1014-13
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
Natural Gas Driven Pneumatic Pump Venting.
As proposed, Subpart W requires oil and gas operators to calculate emissions from natural gas driven pneumatic pump venting using an engineering estimation based on manufacturer model emissions per unit volume and volume pumped. 40 C.F.R. § 98.233(c), 75 Fed. Reg. at 18638. However, the required manufacturer's data is not consistently available for this type of source. Availability of such information varies based on the age of the pump and its manufacturer, and for some older pumps, data may not be available for sufficiently "similar" pump models pursuant to proposed 40 C.F.R. § 98.233(c)(2). Additionally, while IOGA-WV appreciates that the agency has authorized operators to utilize data for a "similar pump model, size and operational characteristics to estimate emissions" where manufacturer data for a specific pump is not available, we note that this creates a highly subjective standard that may vary depending upon the interpretation of the reviewer. IOGA-WV therefore invites USEPA to provide some additional clarification or guidelines with regard to what the agency will deem acceptable under these provisions. Finally, IOGA-WV suggests that, in those cases when both manufacturer data and "similar" pump data is unavailable, USEPA authorize operators to estimate emissions based on industry knowledge and operational history, as long as the basis for such an estimate is properly documented in company records.

Response: Please see EPA's response to EPA-HQ-OAR-2009-0923-1060-28 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1015-40
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Below represents challenges that specific proposed monitoring methodologies pose for many operators.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
			Tracking natural gas bleed rate

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
NG pneumatic high bleed device venting	40 CFR 98.233(a)	1. Natural gas driven pneumatic device continuous bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer. 2. Amount of time in minutes that the pneumatic device has been operational through the reporting period.	during normal operation for every high bleed device will be difficult to compile for the thousands of devices. PAW asks the EPA to propose a reasonable high bleed emission factor to use in place of manufacturer's data if manufacturer's data is unavailable. Further, It is unclear what the EPA means by "continuous." If it is a "continuous" bleed device, why is there a time element in the equation? Lastly, it is unclear at what point is the unit considered not in operation and therefore exempt.
NG pneumatic low bleed device venting	40 CFR 98.233(b)	1. Total number of natural gas pneumatic low bleed devices. 2. For onshore petroleum and natural gas production facilities, concentration of GHG i, CH4 or CO2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHGi equals 1.	It is unclear what the EPA means by "continuous." It is unclear at what point is the unit considered not in operation and therefore exempt. A general note regarding the treatment of high and low-bleed devices: PAW recommends that EPA harmonize treatment of these sources with the API Compendium.
NG driven pneumatic pump venting	40 CFR 98.233(c)	1. Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating	It is unclear at what point is the unit considered not in operation and therefore exempt. It is impractical to keep the records that the EPA is proposing. It does seem from supporting documentation that it is not expected that these sources are a large emitter of GHGs. Therefore, utilizing man-hours to track and maintain a library of emission data

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
		manufacturer. 2. Volume of liquid pumped annually in gallons/year.	from these pumps is overly burdensome to report a relatively small amount of GHG emissions. This data is kept by well-site, not by individual pumps. PAW proposes allowing a site-wide volume of liquid pumped.
Well venting for liquids unloading	40 CFR 98.233(f)	Either Calculation Methodology 1 or 2 must be used to determine emissions for well venting. The same method must be used for the entire reporting year. <u>Calculation Methodology 1:</u> 1. Cumulative amount of time in hours of well venting during the year. 2. Flow Rate in cubic feet per hour, under ambient conditions as required in paragraph (f)(1)(i)(A), (f)(1)(i)(B) and (f)(1)(i)(C) of this section.	Meters are not designed to monitor intermittent flow. As liquids unloading has previously not generally metered, it will be difficult to estimate the orifice size and/or meter capacity in order to provide direct data to calculate this. As the process of installing meters for this purpose will be experimental, PAW proposes that BAMM is used for this estimation for the first reporting year. For smaller wells, calculation methodology 2 would be most appropriate, however the number of hours the well was vented is difficult to monitor. PAW requests the use of BAMM for the first reporting year as operators attempt to resolve this issue.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
		<u>Calculation Methodology 2:</u> 1. Casing diameter (inches). 2. Well depth (feet). 3. Shut-in pressure (psig). 4. Number of vents per year. 5. Sales flow rate of gas well in cubic feet per hour. 6. Hours that the well was left open to the atmosphere during unloading.	
Gas well venting during conventional well completions and workovers	40 CFR 98.233(h)	1. Daily gas production rate in cubic feet per minute. 2. Cumulative amount of time of well venting in minutes during the year.	Yates will need to install flow meters for this requirement. Therefore PAW requests the use of BAMM for the first reporting year.
Gas well venting during unconventional well completions and workovers	40 CFR 98.233(g)	1. Daily gas production rate in cubic feet per minute. 2. Cumulative amount of time of well venting in minutes during the year.	This will require installation of flow meters for this requirement in many instances. PAW requests the use of BAMM for the first reporting year.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
Gathering Pipeline Fugitives	40 CFR 98.233(r)	Use Eq. W-19 to calculate emissions from all sources listed in 98.233(r) - see comment for listed sources. 1. Total number of each type of emission source listed in 98.233(r) 2. For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHGi (CH_4 or CO_2) in produced natural gas or feed natural gas; for other facilities listed in § 98.230 (b)(3) through (b)(8), GHGi equals one.	PAW believes that it is unclear when Production is required to include gathering, and when boosting/processing includes gathering. PAW reiterates that it is unclear in the rule where Production site responsibility ends and Gathering/Processing site responsibility begins.
		3. Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.	
		2. If the tank vapors are continuous then use a meter (such as a turbine meter) to measure tank vapors.	

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
		3. Use the appropriate gas composition from 98.233(u)(2)(iii) (i.e., the GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities).	
		2. Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.	
Reciprocating compressor rod packing venting	40 CFR 98.233(p)	1. Meter volumetric reading of gas emissions per unit time, under ambient conditions. 2. Total time the compressor associated with the venting is operational in the reporting year. 3. Mole percent of GHG i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.	Compressor engines are generally either operational or not. A compressor would not standby pressurized for any amount of time that would affect its emissions significantly as it would be otherwise offset by the fact that the compressor is not operational. Therefore, requiring measurement in each mode is burdensome and does not reflect a significant source of emissions.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
Well testing venting and flaring	40 CFR 98.233(l)	1. Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities. 2. Flow rate in barrels of oil per day for the well being tested. 3. Number of days during the year, the well is tested.	It is not industry standard to determine GOR by individual wellhead. Yates requests the use of BAMM for the first reporting year.
CBM produced water emissions	40 CFR 98.233(r)	1. For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHGi, CH4 or CO2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230 (b)(3) through (b)(8),GHGi equals one. 2. Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.	This source is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs. As measuring emissions from this activity is currently not industry standard, PAW requests the use of BAMM for the first reporting year.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
Acid Gas Removal Vent Stacks	40 CFR 98.233(d)	1. Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition. 2. Volume weighted CO2 content of natural gas into the AGR unit. 3. Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition. 4. Volume weighted CO2 content of natural gas out of the AGR unit.	Acid gas emissions are calculated, not directly measured, using a mass-balance approach: Inlet gas is measured as is outlet gas – the difference is considered to be acid gas. This methodology has been an accepted method with regulatory agencies. Gas that is high in H2S, is highly corrosive: flow meters for acid gas have a high rate of failure and are highly unreliable due to the highly corrosive environment. PAW proposes an additional monitoring methodology using the "mass-balance" approach to calculating acid gas.
Hydrocarbon liquids dissolved CO2	40 CFR 98.233(x)	1. Amount of CO2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions. 2. Total volume of hydrocarbon liquids produced in barrels in the reporting year.	It seems the EPA is assuming that the entrained CO2 will eventually be released, but it is unclear why this assumption is being made. Further, it seems that the level of effort is not commensurate with the amount of CO2 even the EPA expects to be emitted from this source. Also, this source is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
Produced water dissolved CO_2	40 CFR 98.233(y)	1. Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions 2. Total volume of produced water produced in barrels in the reporting year	It seems the EPA is assuming that the entrained CO_2 will eventually be released, but it is unclear why this assumption is being made. Further, it seems that the level of effort is not commensurate with the amount of CO_2 even the EPA expects to be emitted from this source. Also, this source is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs.
Fugitives from valves, connectors, OELs, pressure relief valves, meters, and centrifugal compressor dry seals, pumps, flanges, starter gas vents and other fugitive	40 CFR 98.233(q)	1. Total number of this type of emission source found to be leaking 2. For onshore natural gas processing facilities, concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(3) through (a)(8), GHGi equals 1. 3. Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.	Direct measurement of leaks is very burdensome and expensive, particularly since many upstream activities requiring FLIR surveys are operated in remote locations and difficult to reach. The EPA has repeatedly stated that accessibility is a key factor in determining which sources to require direct measurement of these sources: many of these sites are not easily accessible to field staff.

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
sources.			
Flares	40 CFR 98.233(n)	1. Volume of natural gas sent to flare in cubic feet, during the year. 2. Percent of natural gas combusted by flare (default is 98 percent). 3. Concentration of GHG i in gas to the flare. 4. Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus). 5. Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).	When flares are used in emergency situations, concentration of GHG in the gas flared is not immediately available. PAW requests clarification that it is acceptable to calculate GHG emissions during upset conditions using available concentration data, and correcting the concentration as more accurate data becomes available following an upset condition.
Stationary Combustion Equipment (includi	40 CFR 98.233(z)	1. For portable combustion equipment, use the Tier 1 methodology of Subpart C. The only monitoring	There are several issues here: Does the 25,000 tonne threshold include all combustion equipment in the basin for production facilities? Does this regulation bring all facilities reporting under Subpart C into one larger facility under Subpart W? It is

Source Type	Regulatory reference for calculation/ monitoring requirements	Monitoring requirements/parameters	Comment
ng, but not limited to, engines, turbines, generators)		1 is annual fuel consumption. 2. For stationary combustion equipment, follow the requirements of Subpart C.	unclear how facilities required to report under Subpart C by the standard definition of "facility" would also report under Subpart W. PAW requests clarification/removal of portable combustion equipment

Response: For all pneumatic devices and pneumatic pumps, in today's final rule, EPA is requiring the use of emissions factors. Hence, the reporters only need to count the number of devices to estimate emissions. See the response to comment EPA-HQ-OAR-2009-0923-1060-28. The definitions of continuous and intermittent bleed pneumatic devices are in 40 CFR part 98.6. For the comments on well venting for liquids unloading, EPA recognizes that the determination of gas vented during well unloading is a difficult measurement. EPA considered the methods that Natural Gas STAR partners used in evaluating these emissions and determined that a flow meter on the gas vent line off a gas/liquid separator is the only practical way to measure these emissions. EPA recognizes that the flowback is irregular, and an orifice meter recording may therefore be irregular. Nevertheless, interpreting this meter recording will need some skill where an average flow rate will have to be determined using engineering judgment. EPA disagrees with the commenter that monitoring the time to vent a well during liquids unloading is difficult. For a description of how operating personnel would collect and record the time to vent a well during liquids unloading, please see the response to comment EPA-HQ-OAR-2009-0923-1305-46.

For the comments on gas well venting during conventional well completions and workovers (referred to as gas well venting during completions and workovers without hydraulic fracturing),EPA does not have sufficient information from the comment to determine why the commenter would need meters for conventional completions. Wells are tested after completion to determine their flow rates and producing well flow rates have to be reported to States and are often required for royalty and tax payments. EPA requires the use of this existing data to estimate emissions and does not see the need for any new metering.

In regards to unconventional well completions and workovers (referred to as gas well venting during completions and workovers from hydraulic fracturing), the reporter may use their most recent gas composition based on available sample analysis of the field. EPA has estimated that this should be manageable for most reporters. Please see response to EPA-HQ-OAR-2009-0923-1151-97 for further details on the estimated number of samples. Also, in case the reporter is not able to conduct the required monitoring, under certain conditions, EPA is allowing for the use of BAMM. Please see Section II.E of the preamble to today's final rule for further details.

For the comment requesting clarification on gathering pipelines, EPA has removed this source from today's final rule. See Section II.E of the preamble to today's final rule for further details. In today's final rule, emissions from compressors in onshore petroleum and natural gas production need to be estimated using emissions factor and activity count. This resolves the issue of measuring compressor emissions in different modes of operation for onshore production. Today's final rule allows reporters to use existing GOR data; please see Sections II.D of the preamble to today's final rule for further details. EPA has removed the reporting requirements for CBM produced water emissions from today's final rule. For further details, please also see Section II.E of the preamble to today's final rule and response to EPA-HQ-OAR-2009-0923-1151-129.

Regarding concerns with using flow meters for acid gas, in today's final rule EPA allows the use of engineering estimation to determine flow rate to an Acid Gas Removal unit under certain conditions. See EPA's response to EPA-HQ-OAR-2009-0923-1024-26 for further details. This should avoid any issues with metering where it is not possible.

CO2 in hydrocarbon liquids (mostly crude oil and condensate) does not pass on into today's final products (propane, butane, gasoline, etc.), hence it is a reasonable assumption that the CO2 entrained finally goes to the atmosphere. In today's final rule, EPA has clarified that the source applies only to EOR operations. Further, sampling has been reduced to annual. This should significantly reduce the burden to commenter on this source.

EPA has removed reporting requirements for produced water dissolved CO2 from today's final rule which will address the commenters concerns with this source type. See responses EPA-HQ-OAR-2009-0923-1151-129.

Regarding the comment on equipment leak emissions sources, EPA does not have sufficient details in the comment on why certain sites are not accessible for leak detection. The accessibility that EPA has referred to in its documents relates to the physical reach of the equipment for an operator to conduct leak detection using detection devices that need physical contact. In fact, an IR optical imaging device or IR laser pointing device resolves this issue on equipment access.

In regards to concentration of GHG in gas sent to flares, please see response to EPA-HQ-OAR-2009-0923-1015-12 for further details.
Please see the response to EPA-HQ-OAR-2009-0923-1060-27 for a response to the commenter's questions regarding stationary combustion reporting.

The commenter has requested BAMM for several of the sources. EPA in today's final rule is allowing BAMM for certain source types for specified periods of time. See Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1018-17
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman**:**

Comment Excerpt Text:
Pre-amble-page 78, "Under this approach, if a specific emission source is found not leaking in the initial survey but leaking in subsequent surveys, emissions would be quantified from the date of the first survey where a leak was detected forward through the time when the leak is fixed, or the end of the year, whichever is first. Similarly, if an emissions source is found to be leaking in the initial survey, emissions would be quantified from the date of that survey through to when the leak is repaired, or the end of the year, whichever is first. Under this approach, emissions would reflect leak reductions as determined by repairs and follow-up detection surveys.

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

- CAPP does not have a concern with the outlined methodology for assessing emissions from fugitive equipment leaks based on the timing of the survey and subsequent leak repairs. However, we do not believe that multiple emission surveys per year should be mandatory.

Response: In today's final rule, EPA requires at least one mandatory leak detection survey, but allows for multiple leak detection surveys as long as they are comprehensive. In addition, EPA has provided for the adjustment of emissions based on multiple survey results. Please see Section II.D of the preamble to today's final rule for more details.

Comment Number: EPA-HQ-OAR-2009-0923-1018-25
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (d):
CAPP recommends that the use of a mass balance around the plant or amine unit be an allowed methodology under 98.233 (d) in lieu of the requirement to directly meter V2. CAPP also recommends the redefinition of the variable presented in the formula to: ·

- V1: Metered annual inlet raw gas volume into plant or into amine unit ·

- %Vol1: Volume weighted CO2 content of natural gas or inlet raw gas ·

- %Vol2: Volume weighted CO2 content of sweet sales gas

In addition CAPP believes the requirement for quarterly sampling is not necessary and that the EPA should allow for annual sampling instead.

Response: Please see EPA's response to comment EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1018-53
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
CAPP recommends that in 98.236(c)(19) the venting and fugitive equipment leaks be reported separately. This will provide a more representative picture of the contribution of fugitive equipment leaks to the overall GHG inventory. CAPP would also like to inform the EPA that under 98.236(c)(19)(i) the industry standard is not to prepare actual component counts as this would require effort which is not commensurate with the benefit provided. Instead facilities generally use an estimate based on the count of individual process units and typical component counts for each type of process.

CAPP also seeks clarification on the sampling location the EPA would like used for 98.236(c)(19)(ii) CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production.

Response: EPA agrees with the commenter. Today's final rule requires reporters to report their equipment leaks and vented emissions separately for each respective source. Also, today's final rule allows onshore production reporters to quantify equipment leak emissions by counting major pieces of equipment. For clarification on the sampling requirements for CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production, please see Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1027-10
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
OOC Comment: To prevent confusion, the rule should clearly state that the only subsection from 98.233 that applies to offshore platforms is 98.233(s).

Response: EPA disagrees with the commenter. EPA has reviewed Sections 98.233 and 98.233(s) of today's final rule and has determined that the specific reporting requirements for offshore operators outlined in Section 98.233 are clear and appropriate

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Comment Number: EPA-HQ-OAR-2009-0923-1031-7
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

<u>Comment Excerpt Text:</u>
Direct measurement should not be required. Anadarko feels that direct measurement is not appropriate for any sources for the purposes of GHG emission inventories, consistent with other emission inventory practices. Although EPA has reduced direct measurement requirements in the current proposal for Subpart W, EPA continues to employ methods that ignore longstanding and accepted international protocols for emission inventory calculations. Further, the provision for the use of best available monitoring methods stated in Section 98.3(d)(1) is exclusive to the subparts that were finalized in 2009 and were implemented January 1, 2010. Due to the extensive and comprehensive nature of the monitoring required by Subpart W that is not currently being conducted by this affected industrial category, we request that EPA incorporate an amendment to Section 98.3(d)(1) that allows those subject to any subpart that will be implemented January 1, 2011, to use BAMM for emissions for calendar year 2011.

Response: EPA disagrees with the commenter that direct measurement is not appropriate for any sources. Please see the response to comment EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for a detailed response. In addition, EPA agrees that use of best available monitoring methods should be allowed for some sources; please see the response to EPA-HQ-OAR-2009-0923-1151-64. Additionally, EPA disagrees that use of best available monitoring methods will be necessary for the entire first year for all reporters. For more information, please see the Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1039-32
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Equations should be reviewed for accuracy, clarity and engineering unit consistency: Several comments included in this document (e.g., for blowdown vents) note errors or lack of clarity (e.g., engineering units not provided) related to equations in the Proposed Rule. While a few specific recommendations are provided in these comments, INGAA recommends that EPA closely review all equations for accuracy and consistency (e.g., reference conditions, consistent engineering units for related data, proper application of molar/volume ratio for methane and CO2 content of natural gas), as it is evident that there are additional errors such as engineering units not being provided for all equations. This review is particularly important for equations that are frequently referenced, such as Equation W-20 and Equation W-21 in §98.233(t).

Response: EPA appreciates this comment and has thoroughly reviewed all equations and methodologies in today's final rule for accuracy and consistency.

Comment Number: EPA-HQ-OAR-2009-0923-1039-33
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Equation time basis should be based on operating hours: In many cases, time is (or should be) a variable in the emission calculation. In some cases, it appears that EPA presumes 8,760 hours of operation or source service. INGAA recommends that calculations that assume continuous operation be revised to allow the relevant annual operating hours or time in service to be used to calculate annual emissions.

Response: EPA agrees with the commenter, and has allowed operational hours to be used with select sources (e.g. reciprocating compressor rod packing venting), however, has determined that requiring reporters to track the operational time for equipment leak sources would impose an unjustified burden on reporters. Consequently, EPA assumes when an equipment leak is detected during an equipment leak detection survey that it has been leaking the entire reporting period unless multiple leak detection survey are performed within the reporting period. Please see Section II.E of the preamble to today's final rule for how reporters may adjust their emissions with multiple leak detection surveys.

Comment Number: EPA-HQ-OAR-2009-0923-1040-6
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
Direct measurement should not be required.
Although EPA has reduced some direct measurement requirements from the first Subpart W proposal, EPA still chooses to ignore longstanding and accepted international protocols for emissions calculations that other countries have adopted and currently use to calculate their oil and gas sector emissions. This includes Australia NGERS, EU-ETS, and Alberta for which all emissions are based on the API Compendium-1P1ECA standards. EPA is assuming that better data will result from documenting and calculating emissions from every single small component related to oil and gas production instead of using carefully documented emissions factors applied across larger units. This procedure ignores the rules of probability and statistics and rejects average values in favor of counting every bean. There is no reason to believe that this burdensome method of data collection will produce an emissions number of greater value or validity than other accepted and proven techniques. The proposed rule is considerably more burdensome for onshore facilities than offshore facilities where MMS GOADS reporting standards arc acceptable.

Response: Please see EPA's response to comment EMAIL-0002-9 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1042-15
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§98.233(a) Natural gas pneumatic high bleed device venting

ConocoPhillips Comment:

In order to reduce burden, ConocoPhillips requests the addition of a simplified approach similar to the one suggested for estimating number of fugitive components. i.e. number of pneumatic controllers can be estimated as follows:

1. Require a pneumatic controller count (both types, high bleed and low bleed) for a small number (20) of each type of major equipment (typically controllers are associated with separators, glycol dehydrators, compressors, etc). Inventory the number of each type of major equipment deployed in the reporting unit/area. Multiply the type of pneumatic controller counts by the number of major equipment to arrive at a total pneumatic controller count for the major equipment.
2. Sum the major equipment and site pneumatic controller counts for each reporting area to arrive at the total pneumatic controller count for the reporting area and then apply the methodology specified in the rule (§98.233 (a) & (b)) to arrive at a emission estimate for the reporting unit/area.

Sum the emission estimates for all reporting units/areas within an identified basin for purposes of annual reporting.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23 Please see Section II.E and Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1042-16
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§98.233(b) Natural gas pneumatic low bleed device venting

ConocoPhillips Comment:

ConocoPhillips requests the addition of a simplified approach for estimating the number of low bleed controllers. An approach similar to the one discussed above for high bleed controllers should be allowed. Most of these devices actuate only a few times per day. Probably 99% of our pneumatics are venting << 1% of the time. In order to reduce overestimating emissions, EPA should give us the option to use a statistical approach (i.e. track 2% of sites each year or something similar) to estimate the time factor. The calculation approach would be documented in the GHG Monitoring Plan.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. See Section II.E and Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1060-28
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type:
NG pneumatic high bleed device venting

Regulatory reference for calculation/ monitoring requirements
40 CFR 98.233(a)

Monitoring requirements/parameters:
1. Natural gas driven pneumatic device continuous bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer.
2. Amount of time in minutes that the pneumatic device has been operational through the reporting period.

Comment:
Tracking natural gas bleed rate during normal operation for every high bleed device will be difficult to compile for the thousands of devices owned by Yates Petroleum Corporation. Yates asks the EPA to propose a reasonable high bleed emission factor to use in place of manufacturer's data if manufacturer's data is unavailable. Further, It is unclear what the EPA means by "continuous." If it is a "continuous" bleed device, why is there a time element in the equation? Lastly, it is unclear at what point is the unit considered not in operation and therefore exempt.
Source Type:
NG pneumatic low bleed device venting

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(b)

Monitoring requirements/parameters:
1. Total number of natural gas pneumatic low bleed devices.
2. For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHGi equals 1.

Comment:

It is unclear what the EPA means by "continuous." It is unclear at what point is the unit considered not in operation and therefore exempt. A general note regarding the treatment of high and low-bleed devices: Yates recommends that EPA harmonize treatment of these sources with the API Compendium.

Source Type:
NG driven pneumatic pump venting

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(c)

Monitoring requirements/parameters:
1. Natural gas driven pneumatic pump gas emission in ‘‘emission per volume of liquid pumped at operating pressure’’ in scf/gallon at standard conditions, as provided by the manufacturer.
2. Volume of liquid pumped annually in gallons/year.

Comments:
It is unclear at what point is the unit considered not in operation and therefore exempt. It is impractical to keep the records that the EPA is proposing. It does seem from supporting documentation that it is not expected that these sources are a large emitter of GHGs. Therefore, utilizing man-hours to track and maintain a library of emission data from these pumps (of which YPC operates thousands) is overly burdensome to report a relatively small amount of GHG emissions. This data is kept by well-site, not by individual pumps. YPC proposes allowing a site-wide volume of liquid pumped.

Response: Upon further analysis and review, EPA has determined that good activity data (pneumatic device count) and acceptable emissions estimates from pneumatic devices can be achieved using emissions factors for high bleed, low bleed and intermittent bleed pneumatic controllers. Therefore today’s final rule does not require the reporters to consult instrument vendors for bleed rates or maintain operational records of the time a pneumatic controller is in service. The emission factors for bleeding pneumatic devices are taken from the third edition of the API Compendium. In the context of this rule, the term “continuous” bleed refers to a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

EPA now requires the use of emissions factors for all pneumatic devices in today’s final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. Please see Section II.E and Section II.F of the preamble to today’s final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1074-30
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.233:

Equations should be removed from the proposed rule and placed in a guidance document. This will allow for corrections and updates whenever necessary without prompting a rule change.

Response: EPA disagrees with this comment. In order to change any equations, emissions factors etc., EPA must re-propose the rule and initiate the appropriate public comment process. There is no system by which EPA could simply update equations and factors without prompting a rule change. Hence, EPA has retained the equations in the subpart W rule text.

Comment Number: EPA-HQ-OAR-2009-0923-1082-12
Organization: MidAmerican Energy Holdings Company
Commenter:

<u>Comment Excerpt Text:</u>
EPA seeks comment on whether there are additional or alternative software packages to E&P Tank and GlyCalc that should be required to be used to calculate emissions. (page 65)

MidAmerican is not aware of any other specific software packages that should be considered at this time to calculate emissions. However, alternatives should be considered as they become available as long as they have the necessary functionality to appropriately calculate and capture the data.

Response: EPA now allows reporters to use any software package to calculate onshore production tank emissions that meet the criteria specific in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1100-3
Organization: Linn Energy
Commenter: Paul M. Espenan

<u>Comment Excerpt Text:</u>
Provide streamlined emission-estimating methods for upstream production sites with limited GHG emissions. For these sites, the API Compendium provides a reliable, accurate, and streamlined method of estimating emissions.

Response: EPA disagrees with the commenter. Most "production sites with limited GHG emissions" in the U.S. will likely not cross the 25,000 metric ton CO_2e threshold, and those basin-operators that do cross the threshold have been estimated to emit 85% of the emissions from the petroleum and natural gas sector.

Comment Number: EPA-HQ-OAR-2009-0923-1151-109
Organization: American Petroleum Institute

Commenter: Karin Ritter

Comment Excerpt Text:
Source Category Comments and Alternative Emission Estimation Methodologies

API proposes alternative estimation methodologies for most of the source types applicable to the Onshore Petroleum and Gas Production Sector (OGPG). These alternative methodologies are warranted to reduce the man power and cost burden and to address errors in EPA's assessment of specific sources and methodologies. Also, API recommends that some of the source types be deleted from the final rule because of insignificant GHG emissions associated with them (reasons/examples are provided below for relevant source type discussions).

A. Section 98.233(a) Natural gas pneumatic high bleed device venting

Onshore Production Source Category: Natural gas pneumatic high bleed device venting The proposed rule requires gathering manufacturer data for each unique device model and determining the amount of time each device is operational during the reporting year. API estimates that some 673,000 locations would need to be visited to gather this information, requiring an estimate 667 man-years (based on 2000 hours per year).

The inventorying of pneumatic controllers should be simplified by a method similar to the one suggested for estimating number of fugitive components (provide in item N below). API suggests that the number of pneumatic controllers will be estimated as follows:

1. Require a pneumatic controller count (by high bleed and low bleed types) for a small number (5) of each type of major equipment (typically controllers are associated with separators, glycol dehydrators, compressors, etc) within the Sub-basin entity. Inventory the number of each type of major equipment deployed in the Sub-basin entity. Multiply the type of pneumatic controller counts by the number of major equipment to arrive at a total pneumatic controller count for the major equipment.

2. Sum the major equipment and site pneumatic controller counts for each Sub-basin entity to arrive at the total pneumatic controller count for the Sub-basin entity and then apply the methodology specified in the rule (Section 98.233 (a) & (b)) to arrive at a emission estimate for the Sub-basin entity.

3. Sum the emission estimates for all Sub-basins within an identified Basin entity for purposes of annual reporting.

Per equation W-1, the rule requires calculation of emissions for each pneumatic controller by keeping record of the amount of time the pneumatic controller has been operational through the reporting period. API requests flexibility in determining the operational time of high bleed pneumatic controllers:

1. Where the operational time of high bleed controllers is far less than 8760 hours per year, (as a matter of fact it could be much less than 1% of the time), API requests the option of estimating

operational time based on statistical samples/periodic surveys of the pneumatic controllers in the Sub-basin entity so that a Sub-basin default operational hours/year for each Basin entity can be applied.

2. Where a Sub-basin entity is known to have operated continuously or nearly continuously for the year, API requests the flexibility of estimating emissions based on 8760 hours of operation.

3. Where a Sub-basin entity operates for a portion of the year, API requests the option of adjusting the number of days of operation to correspond to full days that the pneumatic controller and associated equipment at the Sub-basin were in operation

Also, equation W-1 refers to paragraph Section 98.233 (u) to calculate GHG emissions based on the composition of the produced natural gas used to operate the controllers. See Section III comment #39 above for API's suggested revisions to sampling frequency.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. See Sections II.E and II.F of the preamble to today's final rule for further details. In regards to produced natural gas composition, see response to EPA-HQ-OAR-2009-0923-1151-53 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-111
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Where a high bleed pneumatic controller has been retrofitted, such that the manufacturer's information is no longer applicable; API proposes that an emission factor post-retrofit be applied, if available, otherwise the low bleed emission factor should be applied to these pneumatic controllers.

Where a manufacturer or model number can not be determined, due to age of the pneumatic controller or inaccessible information, API requests the use of a default emission factor from the API Compendium.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. See Sections II.E and II.F of the preamble to today's final rule for further details. Where a high bleed device retrofitted to reduce bleed rate is bleeding at or below the low bleed device bleed rate as defined in today's final rule, the reporter should use the low bleed device emissions factor.

Comment Number: EPA-HQ-OAR-2009-0923-1151-113
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(b) Natural gas pneumatic low bleed device venting

Onshore Production Source Category: Natural gas pneumatic low bleed device venting
API proposes the same phased sampling approach and provisions for retrofits or inaccessible information for low bleed pneumatic controllers as described for high bleed pneumatic controllers.

Equation W-2 for low bleed pneumatic controllers incorporates factors for continuous annual operation (24 × 365), rather than using a controller-specific time factor, as provided in Equation W-1. API proposes the same options for determining the operational time of low bleed pneumatic controllers as described above for high bleed pneumatic controllers

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today's final rule for further details. In regards to retrofits to high bleed devices, please see response to EPA-HQ-OAR-2009-0923-1151-111.

Comment Number: EPA-HQ-OAR-2009-0923-1151-115
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(c) Natural gas driven pneumatic pump venting.

Onshore Production Source Category: Natural gas driven pneumatic pump venting
The proposed rule requires gathering manufacturer data for each unique pump model per unit volume of liquid circulation rate at pump speeds and operating pressures, and the amount of liquid pumped annually for individual pumps. Pneumatic pumps are used for the injection of small amounts (i.e., several ounces of fluids over several hours). In addition, the pumps are installed on sumps, which are typically installed on every wellhead and manifold. One API company reports there are approximately 1,000 such pumps spread out over a 600 square mile area with approximately 5 people responsible for maintaining the equipment and visiting a site about every two weeks. On a national level, API estimates that this requirement applies to approximately 520,000 pneumatic pumps and would require 260 man years (based on 2000 hours per year) to gather the required information for the first year. Keeping a log for each pump is impractical. API recommends engineering estimates be used for volume of liquid pumped annually.

Three primary types of pneumatic pumps are used in oil and gas production operations:

- Pneumatic pumps used in association with dehydration units, generally referred to as Kimray pumps. API requests that Section 98.233(b) specifically exclude reporting emissions for pneumatic pumps associated with glycol dehydration units. Emissions from these pumps are already included in the GLYCalc modeling required for the dehydration units and will be captured in emissions reported under Section 98.233(e).

- Piston pumps; and

- Dual diaphragm low pressure pumps.

Operators do not log how much liquid each pump handles, so determining emissions based on the volume handled for each pump would be an excessive burden, as noted above. API requests the following alternatives.

For the piston pumps, company records of the types of pumps and pump curves should be allowed to determine the average amount of gas released per volume of liquid pumped. Emissions can then be quantified for the Sub-basin entity by applying company records of the amount of chemicals or methanol purchased/injected to the average gas usage rates.

For diaphragm pumps, API requests the use of a representative sampling of pumps for the Sub-basin entity to determining the number of strokes per minute and an estimated operational duration for the year. The Sub-basin entity data would be combined with manufacturer information on the amount of gas displaced per stroke to quantify the emissions for a grouping of similar pumps.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. See section II.E of the preamble to today's final rule for further details.

EPA agrees with the commenter with regards to double counting of emissions from glycol circulations pumps. Please see the response to EPA-HQ-OAR-2009-0923-0582-33 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-29
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(a) Natural gas pneumatic high bleed device venting. The equation seems to be geared towards continuous bleed devices. It will be extremely difficult to track the duration of actuation for intermittent bleed devices. API requests that the definition in Section 98.7 match what appears to be requested in Section 98.233(a), which is continuous bleed devices. Therefore, intermittent bleed devices are not addressed.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to the final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-30
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(b) Natural gas pneumatic low bleed device venting. Equation W-2 provides factors to convert between scf of CH_4 and CO_2 to tonnes of CO_2 equivalents. Applying a molar volume conversion of 379.3 scf/lbmole, based on industry standard conditions of 60°F and 1 atm, these emission factors would be 0.0004018 for CH_4 and 0.00005262 for $_{CO2}$. It appears the factors shown for Section 98.233(b) are based on standard conditions of 56°F and 1 atm. API urges EPA to adopt industry standard conditions of 60°F and 1 atm.

Response: EPA has revised today's final rule, and emission factors in Tables W-1A, W-2, W-3, W-4, W-5, W-6, and W-7 are all at standard conditions of 68°F and 14.7 psia, as defined in subpart A.

Comment Number: EPA-HQ-OAR-2009-0923-1151-31
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(b) Natural gas pneumatic low bleed device venting - Paragraph Section 98.233(b) provides the emission calculation methodology for natural gas pneumatic low bleed device venting. The methodology uses number of devices and the emission factors from Tables W-1, W-3, and W-4 to calculation emissions. Paragraph Section 98.233(r) provides the population count and emission factor emission calculation methodology for certain emissions sources including pneumatic low bleed device venting for onshore petroleum and natural gas production facilities (Section 98.232(c)(2)), onshore natural gas transmission compression facilities (Section 98.232(e)(6)), and underground LNG storage facilities (Section 98.232(f)(4)). Paragraph Section 98.233(r) uses the number of devices and emissions factors from Tables W-1, W-3, and W-4 for pneumatic low bleed devices. It appears the calculation methodology in Section 98.233(b) and Section 98.233(r) for pneumatic low bleed devices is duplicative.

17. Table W-2 is missing a Low Bleed Pneumatic Device emission factor, although this table is referenced for the emission factor in Section 98.233(b), Equation W-2.

Response: EPA agrees with the comment, and has revised today's final rule to remove the reference to pneumatic devices from Section 98.233(r). In today's final rule, pneumatic bleed device or pump venting for onshore natural gas processing are not required to be reported, since most of these devices in natural gas processing are driven by air, and may not contribute significantly to GHG emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1151-32
Organization: American Petroleum Institute

Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(c)(2) Natural gas driven pneumatic pump venting. Section 98.233(c)(1)(ii) requires reporters to maintain a log of the amount of liquid pumped annually from individual pumps. Keeping a log for each pump is impractical. API recommends engineering estimates be used for volume of liquid pumped annually. Additional details are provided in Section VII.C of this document.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-95
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(3) and Section 98.233(c): Pneumatic pumps are used in the onshore production sector to pump chemicals, methanol, heat trace fluid, and other materials. An individual well site may have no pneumatic pumps or multiple pumps in different services. API opted to estimate the number chemical and methanol injection pumps rather than apply the value from EPA's national inventory, which appears very low (62,253 CIPs). Assuming that there is an average of one pneumatic pump per gas well and 0.5 pneumatic pumps per oil well, this yields a population of about 520,000 pneumatic pumps. Note this does not include pneumatic pumps associated with dehydrators (commonly referred to as Kimray pumps) because these emissions are accounted for in running the GLYCalc model. The rule requires tracking the amount of liquid pumped and the discharge pressure for each pump, and emissions calculated based on the pump curves for the specific pump. Assuming 81% are covered by the rule, and projecting one hour per pump to fulfill the rule requirements at $100 per hour, yields a total cost of $52 MM.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. This should alleviate any cost concerns related to reporting emissions from pneumatic pumps. See Section II.E of the preamble to today's final rule for further details.

EPA agrees with the commenter with regards to double counting of emissions from glycol circulations pumps. Please see the response to EPA-HQ-OAR-2009-0923-0582-33 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1155-19
Organization: Clean Air Task Force et. al.

Commenter: Pamela Campos

Comment Excerpt Text:
Pneumatic Control Devices

We support WCI's recommendations on emissions reporting for pneumatic control devices. We agree that metering should be required for all high-bleed pneumatic devices and all natural gas powered pneumatic pumps. We agree that engineering calculations using emission factors is appropriate for low-bleed devices.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1167-51
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Noble supports Section VII of the API Subpart W comments and proposed alternative methods as outlined in this section. - Noble generally supports API comment regarding the following emission sources: natural gas pneumatic high bleed device venting, natural gas pneumatic low bleed device venting, well venting for liquids unloading, gas well venting during conventional well completions, gas well venting during conventional well workovers, reciprocating compressor rod packing venting, dehydrator vent stacks, storage Tanks, associated gas venting and flaring , centrifugal compressor wet seal degassing venting, coal bed methane produced water emissions, EOR injection pump blowdown, acid gas removal vent stack, hydrocarbon liquids dissolved CO2, produced water dissolved CO2, and fugitive emissions.

Response: Please see EPA's responses to API comments referenced below for each emission source.

Natural gas pneumatic high bleed device venting and natural gas pneumatic low bleed device venting:
EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today's final rule for further details.

Well venting for liquids unloading:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-118

Gas well venting during well completions without hydraulic fracturing and gas well venting during well workovers without hydraulic fracturing:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-120.

Reciprocating compressor rod packing venting:

Please see the response to comment EPA-HQ-OAR-2009-0923-1151-125

Dehydrator vent:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-117

Storage Tanks:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-121

Associated gas venting and flaring:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-123

Centrifugal compressor wet seal degassing venting:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-124

Coal bed methane produced water emissions:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-129

EOR injection pump blowdown:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-52

Acid gas removal vent stack:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-116

Hydrocarbon liquids dissolved CO2:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-119

Produced water dissolved CO2:
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-129

Equipment leak emissions:.
Please see the response to comment EPA-HQ-OAR-2009-0923-1151-126

Comment Number: EPA-HQ-OAR-2009-0923-1206-34
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Natural gas driven pneumatic pump venting: We request that EPA allow an operator to use an engineering estimate of the count of natural gas driven pneumatic pumps. Therefore, we also request that EPA modify Section 98.233(c)(1)(ii) to allow an operator to maintain a record of the maximum amount of liquid pumped annually from pumps on a facility-wide basis and the emissions are to be calculated on the facility-wide basis as well rather than for each pump.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. This should alleviate burden to report from this sources. Therefore, EPA disagrees with the commenter to allow estimating the count of pneumatic pumps. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-29
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Natural gas pneumatic high-bleed device venting

Section 98.233(a): For a reporter to count and obtain manufacturer's specifications for potentially thousands of high-bleed pneumatic devices presents an excessively costly and time-consuming effort. Therefore, IPAMS requests that EPA allow a reporter to use an engineering estimate of the count of high-bleed pneumatic devices in conjunction with a typical bleed rate to calculate emissions from this source category. This engineering estimate could then be applied on a basin-wide level.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. Please see Sections II.E and II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-30
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Natural gas pneumatic low-bleed device venting

Section 98.233(b): For a reporter to count potentially thousands of low-bleed pneumatic devices presents an excessively costly and time-consuming effort. Therefore, IPAMS requests that EPA allow an operator to use an engineering estimate of the count of low-bleed pneumatic devices. This engineering estimate could then be applied on a basin-wide level.

Response: In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. Please Section II.F of the preamble for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-33
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Natural gas driven pneumatic pump venting

Section 98.233(c): IPAMS requests that EPA allow an operator to use an engineering estimate of the count of natural gas-driven pneumatic pumps. Therefore, IPAMS also requests that EPA modify Section 98.233(c)(1)(ii) to allow an operator to maintain a record of the maximum amount of liquid pumped annually from pumps according to and applied by appropriate size categories.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. This should alleviate burden to report from this sources. Therefore, EPA disagrees with the commenter to allow estimating the count of pneumatic pumps. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1299-15
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

<u>Comment Excerpt Text:</u>
Finally, the technical support document for this proposed rule makes numerous other inapplicable assumptions about LNG facilities, equipment, and practices. First, the document assumes that there are twice as many satellite storage facilities as accounted in the industry. The EPA also assumes that all boiloff from the LNG in storage tanks is re-liquefied by compressors at all facilities, which is not the case. The increase in the universe of LNG facilities, the presumption that all facilities operate numerous compressors (instead of the LNG pumps used in most of those instances), and the assumption that the compressors used are all of the higher-emission type common to other industry segments, along with the misunderstandings noted above regarding specialized equipment and the vigilant operations and maintenance practices in place at these facilities, all render inapplicable the subjects and methods proposed for quantifying emissions of greenhouse gases from LNG facilities.

Response: EPA disagrees with the commenter on LNG facilities. The listing of satellite storage facilities is as provided in the data source available from Gas Technology Institute and listed in the references to the rule. Hence, EPA did not estimate these facilities, rather used a published data set. However, EPA's analysis demonstrated almost none of the satellite facilities cross the threshold. With regards to compressors, EPA agrees that if an LNG facility does not have any compressors then they simply do not report for that source. The commenter does not provide any analysis or measurement data to back its assertions that compressor emissions from LNG facilities are lower than other compressor stations. Also, LNG facilities in most cases handle natural gas and hence are liable to equipment leaks just like in other gas handling facilities. Hence, EPA has retained the requirements for reporting from LNG facilities.

Comment Number: EPA-HQ-OAR-2009-0923-1305-16
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>

Section 98.233(a) Natural gas pneumatic high bleed device venting

The equation seems to be geared towards continuous bleed devices. It will be extremely difficult to track the duration of actuation for intermittent bleed devices. We request that the definition in 98.7 match what appears to be requested in 98.233(a), which is continuous bleed devices. Therefore, intermittent bleed devices are not addressed. Retaining a record of the minutes that a particular device is operational is not feasible

H. Section 98.233(b) Natural gas pneumatic low bleed device venting.

Equation W-2 provides factors to convert between scf of CH_4 and CO_2 to tonnes of CO_2 equivalents. Applying a molar volume conversion of 379.3 scf/lbmole, based on industry standard conditions of 60 degrees F and 1 atm, these emission factors would be 0.0004018 for CH_4 and 0.00005262 for CO_2. It appears the factors shown for 98.233(b) are based on standard conditions of 56°F and 1 atm. EPA should adopt industry standard conditions of 60°F and 1 atm.

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today's final rule for further details.
Please see comment EPA-HQ-OAR-2009-0923-1151-30 for a response to the emissions factor values.

Comment Number: EPA-HQ-OAR-2009-0923-1305-18
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(c)(1)(ii)

Section 98.233(c)(1)(ii) requires reporters to maintain a log of the amount of liquid pumped annually from individual pumps. Keeping a log for each pump is impractical. BP recommends engineering estimates be used for volume of liquid pumped annually.

Response: EPA now requires the use of emissions factors for pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of pumps to estimate emissions. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-45
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(a) Natural gas pneumatic high bleed device venting

The proposed rule requires inventorying and gathering manufacturer data for each unique device model, and determining the amount of time each device is operations during the reporting year. To accomplish this, each individual site would have to be visited and the specific model number and type of controller determined and logged.

To enable this inventory, BP suggests that it be spread over a 3 year period with 1/3 of the sites being inventoried each year. For the first two years the inventory conducted would be applied to the total site population.

Per equation W-1, the rule requires calculation of emissions for each pneumatic controller by keeping record of the amount of time the pneumatic controller has been operational through the reporting period.

- Where a sub-basin entity is known to have operated continuously or nearly continuously for the year, BP requests the flexibility of estimating emissions based on 8760 hours of operation.

- Where a sub-basin entity operates for a portion of the year, BP requests the option of adjusting the number of days of operation to correspond to full days that the pneumatic

Where a manufacturer or model number can not be determined, due to age of the pneumatic controller or inaccessible information, BP requests the use of a default emission factor from the API Compendium.

B. Section 98.233(b) Natural gas pneumatic low bleed device venting

BP proposes the same phased approach and provisions for low bleed pneumatic controllers as described for high bleed pneumatic controllers.

C. Section 98.233(c) Natural gas driven pneumatic pump venting.

The proposed rule requires gathering manufacturer data for each unique pump model, per unit volume of gas usage per unit of liquid pumped at pump speeds and operating pressures, and the amount of liquid pumped annually for individual pumps. Keeping a log for each pump is not practical and BP recommends engineering estimates be used for volume of liquid pumped annually.

Three primary types of pneumatic pumps are used in oil and gas production operations:

- Pneumatic pumps used in association with dehydration units, generally referred to as Kimray pumps. BP requests that 98.233(b) specifically exclude reporting emissions for pneumatic pumps associated with glycol dehydration units. Emissions from these pumps are already included in the GLYCalc modeling required for the dehydration units and will be captured in emissions reported under 98.233(e).

- Piston pumps; and

- Dual diaphragm low pressure pumps.

Operators do not typically track how much liquid each pump handles, so determining emissions based on the volume handled for each pump would be an excessive burden, as noted above. BP requests the following alternatives:

- For the piston pumps, company records of the types of pumps and pump curves should be allowed to determine the average amount of gas released per volume of liquid pumped. Emissions can then be quantified for the reporting unit by applying company records of the amount of chemicals or methanol purchased/injected to the average gas usage rates.

- For diaphragm pumps, BP requests the use of a representative sampling of pumps for the reporting unit to determining the number of strokes per minute and an estimated operational duration for the year. The reporting unit data would be combined with manufacturer information on the amount of gas displaced per stroke to quantify the emissions for a grouping of similar pumps.

Response: EPA now requires the use of emissions factors for all pneumatic devices and pneumatic pumps in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. In regards to estimating pneumatic device counts, please see response to EPA-HQ-OAR-2009-0923-0582-23. This should alleviate burden to report from this sources. Therefore, EPA disagrees with the commenter to allow a phased in approach for these devices. Please see Sections II.E and II.F of the preamble to today's final rule for further details. EPA agrees with the commenter with regards to double counting of emissions from glycol circulations pumps. Please see the response to EPA-HQ-OAR-2009-0923-0582-33 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-3568.3-2
Organization: Sierra Club
Commenter: Anne Harvey

Comment Excerpt Text:

In our comments on the full reporting role, we discussed how engineering estimates and emissions factor-based approaches had often underestimated emissions, and in particular, fugitive emissions from oil and gas facilities. We're concerned that EPA has moved too far away from direct measurement in this proposed role in favor of a range of estimation approaches. We encourage EPA to carefully consider whether this decision causes any loss in accuracy and precision and whether such losses can be justified given the reporting rules focus on comprehensive and detailed information.

Response: EPA has chosen monitoring methods to balance between emissions accuracy and cost to industry. Using costly monitoring methods for marginal gains in emissions accuracy does not provide much benefit in terms of policy making. Hence, although EPA has chosen emissions factors and engineering estimates for several monitoring methods, those methods will provide sufficient clarity in terms of magnitude of emissions for any future policy considerations.

Comment Number: EPA-HQ-OAR-2009-0923-3568.5-7
Organization: Environmental Defense Fund
Commenter: Peter Zalzal

Comment Excerpt Text:
As a general rule, emissions data derived from direct measurement is more accurate than data derived from engineering estimates and emissions factors. In the oil and gas sector, this rings especially true because emissions factors tend to be based on older sources of data and considerable variability can exist between sites due to differences in operations and maintenance conditions. For example, although two oil and gas sites may have the same number of components and types of equipment, if the operator of one site invests considerably more resources into maintenance and leak detection of his equipment, the overall leak rate on a per-component basis for that site will be much less than alternative sites. Components with higher occurrence of leaking such as compressors and equipment with less rigorous or dated emissions factors, should therefore be required to utilize direct measurement over engineering estimates.

Response: EPA agrees with the commenter that there is some variation between facilities in terms of equipment leaks. However, EPA concluded that requiring leak detection and the application of leaker emissions factors will substantially mitigate that issue. Furthermore, leaks occurring across facilities still leak at similar average rates; i.e., connector leak across different facilities will have similar average leak rates. The impact of maintenance practices will be reflected in the number of leaks and not as much in the average leak rate. Hence, EPA has retained the requirements for emissions factors in today's final rule.

13.2.1 WELL VENTING, COMPLETION AND UNLOADING CALCULATIONS

Comment Number: EPA-HQ-OAR-2009-0923-0582-25
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Measurement Options: WCI evaluated the following four options.

Option	Pros	Cons
1). Emission Factors Estimation based on GRI/USEPA emissions factor	Simplest method.	Data quality questionable. Duration of blowdown not measured. Assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow. Does not generate cap-and-trade quality data.
2). CAPP isentropic flow model Assume isentropic flow through a nozzle to calculate total mass flow rate (liquid and gas), and calculate gas mass flow rate.	More accurate than Option 1	Does not determine individual blowdown event emissions but assumes that all events are of the same duration. Calculates depressurization emissions only.
3). API (2009) Calculate emissions based on well shut-in pressure. Similar to CAPP model.	More accurate than Option 1	Calculates depressurization emissions only. Assumes that each blowdown event is the same duration.
4). USEPA (2010) Direct measurement – three methods: a) well venting for liquids unloading b) unconventional well venting – completions and workovers c) conventional well venting – completions and workovers	Accurate method if measurement is done on individual wells	Requires measurement of gas flow during well completions and workers.

WCI Recommendation: USEPA's approach to calculating emissions from well venting is the most accurate of the available methods. WCI recommends the use of USEPA's approach (option 4) with modifications to SECTION 98.233(f) and (g). WCI recommends the SECTION 98.233(h) be adopted without modification.

WCI Modifications: WCI recommends the following modifications to USEPA's approach:

(1) Well venting for liquids unloading (SECTION 98.233(f))

Limit options to Calculation Method 2 where individual well unloading event emissions are calculated.

Draft Calculation method 1 requires use of a recording flow meter only for each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in tubing. In addition, Calculation method 1 only requires measurement of flow in each unique combination, every other year. Thus Calculation method 1 would not produce cap-and-trade quality data.

(2) Gas well venting during unconventional well completions and workovers (SECTION 98.233(g))

Use either Calculation Method (1) or (2), for each well completion and workover.

The proposed USEPA method requires measurement of flow rate only for each unique tubing diameter and producing horizon/formation in each producing field every other year. This limited sampling would not result in cap-and-trade quality data. Therefore, WCI recommends that these methods be applied to every well completion and workover. Text should be added stating that in situations where vented gas is captured for use (e.g., green completions) reporting emissions would not be required. If vent gas is sent to a flare emissions would be calculated in the flare section – section (n).

Response: EPA disagrees with the commenter. The rule has proposed methodologies that estimate emissions from sources within a level of accuracy that effectively informs future policy. Tightening reporting methodologies for greater accuracy will come at a substantially higher cost, which cannot be justified by the incremental accuracy gains for the purposes of this rule. Therefore, EPA has retained the well venting monitoring methods as proposed in the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002).

Comment Number: EPA-HQ-OAR-2009-0923-0956-2
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

<u>Comment Excerpt Text:</u>
(98.233 (g)) Many times the producer knows the choke size of wells that are venting to the atmosphere. Accurate gas rates can be calculated knowing the upstream pressure, choke size and downstream pressure. Would the EPA consider this as a method to calculate vented gas rates?

Response: EPA is not recommending a flow calculation across the well choke for liquids unloading because there are two more accurate methods required in today's final rule: a vent meter or calculations based on well dimensions and operating parameters. Choke calculations during transient pressure flow can be a complex calculation with sonic flow part of the time and subsonic flow for all or the remainder of the unloading time. The pressure upstream of the tubing string and choke is very uncertain with liquids being lifted inefficiently without a plunger lift and highly variable depending on the amount of liquid accumulation at the time a well is selected for liquid unloading. EPA has decided that the direct measurement of vent gas or the equations based on well depth, casing diameter, tubing diameter, shut-in and sales line pressures, and venting time will be cost-effective and adequately accurate in characterizing emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1011-11
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233(g) Gas well venting during unconventional well completions and workovers.—As in several other recommendations related to providing reporters monitoring flexibility, El Paso requests the third method from the Technical Support Document be included as an alternative method in the rule, since the approach uses information commonly tracked from completion and workover activities.

Response: EPA disagrees with the commenter. Although the option is listed in the TSD, the flow rate during completions and workovers is often more than the flow rate during normal production. This is because during a completion or workover there is no restriction to the flow of the well, unlike during production wherein the choke at the wellhead controls the flow rate. Also, EPA has already provided this option for well completions and well workovers that do not need hydraulic fracturing. However, when a hydraulic fracture is conducted the flow rate and time for well completions are significantly higher. Hence, EPA wants to correctly capture this information. Finally, EPA has analyzed and determined that the samples required with well completions and well workovers that require hydraulic fractures is manageable. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-97.

Comment Number: EPA-HQ-OAR-2009-0923-1011-40
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(g) Gas well venting during unconventional well completions and workovers

El Paso estimates that it would have to report emissions for approximately 3,500 unconventional and conventional completions or workovers using the basin level reporting threshold.

EPA assumes that the majority of unconventional wells are completed with hydraulic fracturing. The proposed rule details two different methodologies for estimating emissions from unconventional well completions or workovers:

- Method #1 requires the measurement of flow rate during clean-up for one well completion and

one well work-over in each field. From this a flow rate per minute is derived and applied to the minutes of flow-back from each completion and work-over in a field.
- Method #2 requires monitoring across the completion choke and calculation of flow rate during clean-up for one well completion and one well work-over in each field. From this a flow rate per minute is derived and applied to the minutes of flow-back from each completion and work-over in a field.

The TSD considered a third method for determining emissions from completions and workovers. Method 3 is based on the daily gas production rate, the amount of venting time, and the composition of CH_4 and CO_2 in the produced gas. This approach uses information commonly tracked from completion and workover activities and should be included as an alternative method in the rule.

Response: EPA disagrees with this comment. With regards to the third method in the TSD referenced for calculating emissions from completions and workovers, please see the response to EPA-HQ-OAR-2009-0923-1011-11.

Comment Number: EPA-HQ-OAR-2009-0923-1014-14
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
Well Venting for Liquids Unloading
With regard to well venting from liquids unloading, Subpart W proposes to require oil and gas operators to monitor emissions using one of the following alternatives: (1) engineering estimation based on a field-specific emissions factor multiplied by the number of events or (2) direct measurement using a flow-metered emissions factor multiplied by the number of events. 40 C.F.R. § 98.233(1), 75 Fed. Reg. at 18639. Given the large number of wells that a single oil and gas operator can control, however, installing a flow meter on each vent line is impractical. The necessary maintenance of the meter and the time required to monitor and subsequently compile the information into useful data is extensive for the minimal amount of emissions that occur during this process. Moreover, the engineering estimation will be well-specific and will also require considerable time and expense to complete for each well. Particularly if USEPA retains its basin-level definition of an onshore production facility, these requirements could apply to hundreds or thousands of wells within a particular basin, thereby creating an enormous burden on operators. Because this process is not a significant source of GHG emissions, and because the burdens associated with calculating these emissions outweigh the environmental benefits associated with quantifying the minimal emissions associated with this process, IOGA-WV urges the elimination of this section from the final rule.

Response: EPA disagrees with the commenter on the methodology issue for calculating emissions from well venting from liquids unloading or the exclusion of the source from reporting. EPA provided two alternatives in the proposal to estimate emissions from this source. The first is an engineering estimation method that applies to all wells. In this methodology the only two unknown parameters are number of times the wells are unloaded and the time required for liquids unloading. This parameter can be tracked using a log by the operator who opens the well to the atmosphere where unloading is manually conducted. In the case of plunger lifts, the timing cycle of the plunger can be tracked to determine hours required for unloading. The well depth, shut-in pressure, and casing/ tubing diameter are all known data for operators. Hence conducting this calculation is partly desktop and not resource intensive, since no new equipment of monitoring methods have to be put in place.

The second alternative provided in the proposal was to estimate unloading emissions using meters on each unique well tubing diameter and producing horizon/ formation combination in gas producing field where liquids unloading occur. EPA wishes to clarify that the intent is to meter representative wells in a field and not meter every single well. The representative sample emissions should then be extrapolated to all wells that the sampled well represents. This is the least burdensome way of estimating emissions that are reasonably accurate.

Finally, EPA would like to highlight that the emissions from well liquids unloading are 34 percent of the total emissions from onshore production. Hence due to its significance EPA did not consider it appropriate to exclude the source from reporting. In today's final rule, EPA has retained the proposal methodology for well liquids unloading.

Comment Number: EPA-HQ-OAR-2009-0923-1018-29
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (g):
CAPP would like clarification on 98.233 (g)(i) and requests that the EPA provide a definition of a "gas producing field", as well as guidance on how to distinguish fields. Additionally under 98.233(g)(i)(A) CAPP requests that the EPA provides guidance on how to calculate the emissions from a well completion within the field.

Response: EPA agrees with the commenter. In today's final rule, EPA has provided a definition of a gas well that should be used to apply monitoring methods. Also, EPA has provided calculation methods for estimating emissions using pressure drop readings across a choke in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1018-30
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (h):
When reviewing 98.233(h) CAPP noticed that equation W-9 is incorrect as it references Daily Gas Production Rate. This equation would be correct if the back-pressure remained constant, however since it fluctuates, equation W-9 should be changed to incorporate the correlation between venting and well back-pressure.

Response: EPA agrees with the commenter and understands that the back-pressure varies over time. Hence in today's final rule, the equation requires the calculation of the production rate using an annual average that will balance out the changes in the back-pressure over a year. To keep the calculation method simple, EPA requires the use of an average value.

Comment Number: EPA-HQ-OAR-2009-0923-1026-11
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
It is unclear if valve operators are intended to be included in vented emissions as they appear to be excluded from pneumatic devices. EPA should clarify whether valve operators are to be included as a vented emission or as part of the pneumatic device with which it is associated

Response: Upon further analysis and review, EPA has determined in today's final rule that high bleed, low bleed and intermittent bleed gas pneumatic controllers shall be reported using component counts and population emission factors. These emission factors cover each natural gas powered, automated process control loop such as level, temperature and pressure controllers. Manual, natural gas powered isolation or shut-off valves and non-venting pneumatic pressure regulators are not included in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1026-5
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
Well Completion Emission Factor

For well completion venting and well work-over venting EPA proposes the development of a field-specific emission factor either by direct measurement of flow rate or hydrocarbons (not methane) using a meter or by an engineering estimation based on well choke pressure drop. One representative well completion and one well work-over per field horizon must be developed to characterize emissions per day of venting from all other completions and workovers in that field horizon. This factor must be updated every two years. Dominion requests that the emission factor be determined once for each horizon and updated at the operator's discretion based on the operator's knowledge of that formation

Response: EPA has provided the least burdensome monitoring method that provides reasonable accurate information. The field-specific emissions factors, however, have to be developed on a once-in-two-years basis and reported on an annual basis. This is required for EPA to track progress or deterioration in emissions levels. In addition, EPA cannot put verification and auditing systems in place that allows for discretion of individual operations.

Comment Number: EPA-HQ-OAR-2009-0923-1038-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

<u>Comment Excerpt Text:</u>
(98.233 (a)(b)) High bleed devices must be calculated on a separate per device basis while low bleed device calculations let you just put in a factor for all. Why not have a factor for high bleed devices to make this part of the rule more uniform and easier to use

Response: EPA now requires the use of emissions factors for all pneumatic devices in today's final rule. Hence, the reporters only need to count the number of devices to estimate emissions. See Section II.E of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1040-20
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

<u>Comment Excerpt Text:</u>
98.233(2),(h):
Gas well venting during unconventional well completions and workovers and gas well venting during conventional well completions and workovers: EPA provides two calculation methodologies for unconventional wells and one calculation methodology available for conventional wells. For the purposes of calculating GHG emissions under Subpart W, there is no valid reason to make a distinction between "conventional" and "unconventional" wells. We request that EPA make available all three calculation methodologies for all well completions and workovers, regardless of whether the well is considered "conventional" or "unconventional."

Response: EPA disagrees with the commenter. EPA has provided two different methodologies for unconventional and conventional well completions and workovers (now referred to as well completions "from" and "without" hydraulic fracturing) after careful consideration. Typically, unconventional well completions and workovers require hydraulic fracturing that take longer and vent more gas than do conventional well completions and workovers. Hence, EPA has provided more detailed methods for well completions and workovers from hydraulic fracturing. Also, in today's final rule, EPA has made the source categorization clearer by distinguishing between well completions and workovers that do or do not require hydraulic fracturing. In addition, well workovers that do not require fracturing use a simple emissions factor. With regards to the third method in the TSD, please see the response to EPA-HQ-OAR-2009-0923-1011-11.

Comment Number: EPA-HQ-OAR-2009-0923-1042-18
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
§98.233(f) Well venting for liquids unloading

ConocoPhillips Comment:

At §98.233(f)(1)(i), the calculation methodology for Well Venting for Liquids Unloading requires the use of a recording flow meter to record the gas flows. ConocoPhillips requests EPA add the option to use a well choke as in §98.233(g)(1)(ii). ConocoPhillips Alaska routinely uses the choke method to measure flow. This method is accurate and, more importantly, safe. When gas vents, the devices used to measure that venting must be Class I, Division I approved. Even such approval involves risk we prefer not to incur. Our practice has been to employ portable skid-mounted pressure gauges or chokes that are not electric. We manually record the pressure readings from these gauges or chokes and use that data to calculate the gas flow rates. We request that EPA extend this ability to use non-electric gauges or chokes with manual recording to all well work activities.

Response: EPA is not allowing a flow calculation across the well choke for liquids unloading. See response to comment EPA-HQ-OAR-2009-0923-0956-2 for more information.

Comment Number: EPA-HQ-OAR-2009-0923-1043-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
(98.233 (c)) Under natural gas driven pumps, it requires you to maintain a log of the amount of liquid pumped. This brings up a larger question in terms of what type of accuracy is the EPA looking for in these logs and how much supporting documentation do you need? (For example, if you are using a diaphram pump to pump out storm water from diked areas, do we need to have a meter on the pump or can we make an estimate based on rainfall that year

Response: In today's final rule, EPA has simplified the monitoring method for natural gas driven pumps and required the use of emissions factors. For this monitoring method only a count of the pneumatic pumps is required. For further details, please refer to Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1056-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
(98.233 (f)(1)(C)(ii)) The equation assumes that the casing is vented to the atmosphere. Many wells uses tubing strings with packers which limits the amount of blowdown gas. Should the equation be modified to use vented tubular (pipe) diameter instead of casing diameter when tubing and packing is in the well

Response: In today's final rule, EPA's method for calculating well venting for liquids unloading does not assume that the casing is vented to the atmosphere directly. Rather, that liquid accumulation in the tubing string, as it suppresses gas flow to the sales line, gradually shuts in the well just the same as if the well were shut-in at the wellhead. Thus, reservoir flow slows and pressure surrounding the well perforations builds to shut-in pressure, which fills the casing outside the tubing with a bubble of gas at or near shut-in pressure. It is this bubble of high pressure gas, in conjunction with removal of sales line back pressure, that provides a rush of gas flow up the tubing during venting that attempts to lift the liquids accumulation to the surface. EPA chose to not add complexity in the equations for well liquids unloading venting the effects of tubing packers. EPA understands tubing packers reduce the gas available to expel the liquids and determined that the smaller bubble of gas inside the casing will compound the inefficiency of lifting liquids without a plunger lift. EPA considers it likely that well venting for liquids unloading may require continued venting beyond the average time that EPA calculated to expel the full well depth of gas accumulation in the casing. Hence, to inform future policy in the most cost-effective way, the simple equation including venting time would compensate for the additional complexity of evaluating the gas bubble with myriad combinations of wells with tubing packers. Please see EPA-HQ-OAR-2009-0923 "Change to Rule Equation W-7: Time to Vent the Casing Gas from Well Liquids Unloading" for more details.

Comment Number: EPA-HQ-OAR-2009-0923-1060-17
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:

Source Type:
Well venting for liquids unloading

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(f)

Monitoring requirements/parameters:
Either Calculation Methodology 1 or 2 must be used to determine emissions for well venting. The same method must be used for the entire reporting year.
Calculation Methodology 1:
1. Cumulative amount of time in hours of well venting during the year.
2. Flow Rate in cubic feet per hour, under ambient conditions as required in paragraph (f)(1)(i)(A), (f)(1)(i)(B) and (f)(1)(i)(C) of this section.
Calculation Methodology 2:
1. Casing diameter (inches).
2. Well depth (feet).
3. Shut-in pressure (psig).
4. Number of vents per year.
5. Sales flow rate of gas well in cubic feet per hour.
6. Hours that the well was left open to the atmosphere during unloading.

Comments:
Meters are not designed to monitor intermittent flow. As liquids unloading has previously not generally metered, it will be difficult to estimate the orifice size and/or meter capacity in order to provide direct data to calculate this. As the process of installing meters for this purpose will be experimental, Yates proposes that BAMM is used for this estimation for the first reporting year. For smaller wells, calculation methodology 2 would be most appropriate, however the number of hours the well was vented is difficult to monitor. Yates requests the use of BAMM for the first

reporting year as operators attempt to resolve this issue.

Source Type:
Gas well venting during conventional well completions and workovers

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(h)

Monitoring requirements/parameters:
1. Daily gas production rate in cubic feet per minute.
2. Cumulative amount of time of well venting in minutes during the year.

Comments:
Yates will need to install flow meters for this requirement. Therefore Yates requests the use of BAMM for the first reporting year.

Source Type:
Gas well venting during unconventional well completions and workovers

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(g)

Monitoring requirements/parameters:
1. Daily gas production rate in cubic feet per minute.
2. Cumulative amount of time of well venting in minutes during the year.

Comments:
Yates will need to install flow meters for this requirement. Therefore Yates requests the use of BAMM for the first reporting year.

Response: In today's final rule, EPA provides options to use BAMM for certain sources for specified time periods and allows reporters to petition for BAMM for other sources that meet certain criteria. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1074-32
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(f):

WBIH requests EPA reconsider the calculation methodology for well venting for liquids unloading. The venting is a combination of gas and water and is not in a consistent proportion - gas venting is variable

Response: EPA agrees that the unloading is not a single phase flow. However, the monitoring methods required provide a best possible approximation of emissions without unreasonable burden for monitoring. Hence, EPA has retained the proposal monitoring method in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1074-33
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(g):

WBIH requests EPA reconsider the calculation methodology for well venting for liquids unloading. Gas venting is variable. For the well completions, the venting is a combination of gas, water and sand; and for the workovers, air is injected during the process.

Response: EPA has provided adjustments to the monitoring methods to account for CO_2 and CH_4 emissions only such that any air injected in a workover process does not get accounted as emissions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1074-32.

Comment Number: EPA-HQ-OAR-2009-0923-1074-35
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(h) and 98.233(l):

WBIH requests the removal of the word "venting" and the associated calculations for "venting". Gas is not vented during testing - gas goes to the flare

Response: There are certain parts of the country where gas is not flared due to various reasons, including safety and fire hazard. In such cases, gas from the testing is vented and hence EPA has retained the term in today's final rule. Additionally, the use of the term or lack thereof does not have any consequence on the monitoring method required.

Comment Number: EPA-HQ-OAR-2009-0923-1151-118
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(f) Well venting for liquids unloading.

Onshore Production Source Category: Well venting for liquids unloading

API appreciates EPA's provision of alternate methodologies for estimating emissions from venting of gas wells to unload liquids and urges EPA to retain both options. However, we believe that the methodologies described by EPA in the proposed rule are unnecessarily complex, burdensome and can be significantly improved while still yielding high quality data. As structured in the proposed rule, operators are required to use one of two methods to determine venting emissions. For clarity, each method and alternative is discussed separately.

Method #1 As Proposed by EPA: This method requires that operators measure emissions from one vent per "unique well tubing diameter and producing horizon/formation combination in each gas producing field" (presumed to be a named field as identified in the EIA's field list referenced in the proposed rule) and then apply the venting rate to all other wells in the same "unique combination" on a venting time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields), API estimates a total of 94,000 unique venting measurements would be required to encompass the unique combinations of fields, producing horizons/formations, tubing diameters, and operators. At a projected cost of $1,000 per measurement (a conservative cost for temporary piping modifications, installation of a temporary recording flow-meter, conducting the measurements, and returning the piping to its original configuration), the cost of measurement would be $94 MM. Assuming 2.5 hours per field/tubing size/operator combination (94,000) and $100 per hour to track venting by combination and perform the calculations for emissions estimation, an additional cost of $23.5 MM is projected. API estimates a total cost of $117.9 million to uniformly implement the Method #1 requirements, which would be fully repeated every two years with a lower burden and cost in the interim years between measurements. To address this problem, API suggests the following:

Method #1 Alternative as Proposed by API: Rather than requiring venting measurements for each field, allow field groupings in a particular basin (Sub-basin entity) on a producing horizon/formation specific basis with no distinction for different tubing sizes. In a producing area, the production from a particular producing horizon/formation tends to be quite uniform and operators tend to use the same or very similar tubing sizes. Also, the venting rate is much more dependent on the producing horizon/formation pressure, reservoir flow dynamics, and operating pressures (determined by the collection system pressures which tend to be uniform) than the tubing size. Operators would establish a venting rate, based on the measurements for each Sub-basin entity, and then track the total venting time on a producing horizon/formation basis to arrive at an emissions estimate for the Sub-basin entity. For wells which are completed in and producing from multiple producing horizons/formations, the venting rate would be assumed to be the higher rate established for the applicable producing horizons/formations being produced. Although the reduction in reporting burden is difficult to forecast, it could be substantial when compared against the proposed EPA methodology.

Method #2 As Proposed by EPA: Method #2 requires calculation of the "blow-down" volume from de-pressuring each individual well-bore and then adding the reservoir flow component based on time and the individual well's production rate. This requires tracking, at an individual well level, both the number and time of each individual venting event. With the large number of gas wells subject to the rule (estimated as 373,000) and using EPA's estimate of the percentage of these which vent (41.3%), API estimates about 154,000 individual well-bore de-pressuring calculations would be required. Using EPA's estimate of an average of 31 discrete vent instances per venting well per year would require tracking of the number and time of some 4.7 million discrete venting instances per year. To arrive at an emission estimate would require subsequently calculating emissions for each of the 154,000 wells and then summing these emissions, on a Basin entity level, for annual emissions. Assuming 0.5 hours total per well to calculate the well-bore de-pressuring volume for each affected well; 0.1 hours per event to track, QA/QC, and log the time; and 0.2 hours per well to calculate and QA/QC the vent volumes to arrive at an emissions estimate at $100 per hour, yields an estimated 293 man years of time (at 2,000 hours/yr) and $58.5 MM cost for this method.

The variables used in this method make it more difficult to apply to plunger lift venting and for data gathering/assumptions. The issues with each of the variables are:

- Casing Diameter - The volume that would be vented during a plunger vent should only be the volume of gas above the plunger in the tubing. The gas occupying the casing should have no impact on the volume of gas that will be released during the vent. For plunger venting, using the tubing diameter for the volumetric portion of the calculation would be more appropriate. This method assumes the entire casing volume is vented each time, which is not the case for a normal vent event on plunger lift wells.

- Well Depth - This variable is a decent input for the volume that would be released but as is mentioned above, the volume above the plunger is all that should be vented. The plunger normally runs to the bottom of the tubing where it impacts a spring set in the seating nipple. In the worst case scenario, where a plunger is vented from the bottom of the tubing, the maximum displacement is represented by the volume contained within the tubing which is dependent on the length of that tubing. In some cases the depth of the tubing and well may not be significantly different, but in others there could be a very large interval of open wellbore below the end of the tubing. For this reason it would be more appropriate to use tubing depth rather that well depth when determining the volume vented during a plunger vent.

- Shut-in Pressure – Is this value the shut-in pressure right before the vent (casing or tubing?) or the normal shut-in pressure of the reservoir? Both would require gathering additional vent or reservoir data. Plunger wells are configured to vent only after a lifting period has elapsed. The shut-in pressure of the well does not accurately represent the pressure of the tubing directly before a vent occurrence. In order to determine the volume of gas that will be vented from the tubing it is necessary to know the pressure of the gas occupying the tubing, this would be more accurately represented by tubing pressure or line pressure if tubing pressure is not available.

- Sales Flow Rate – We find no logic or justification for including the sales volume in addition to the vented volume. Provided the plunger lift controller equipment is counting vent events properly, the sales flow rate should not be a consideration in determining the plunger vent volumes. Plunger vents should only be venting the gas above the plunger which is represented by the volumetric portion of the calculation. Applying the sales rate would artificially increase the reported volume. This would also require gathering flow rate data for each well at the time of the vent event.

As prescribed, Method 2 would require the collection of more vent data (pressure, rate and vent time) and overestimate the vent volume due to the use of the entire casing volume plus sales flow rate. If the method were altered to use entire tubing volume, tubing pressure and omitted the sales flow rate it would be more applicable to plunger lift wells.

Method #2 Alternative as Proposed by API: Rather than requiring the calculation of the well-bore de-pressuring volume for each individual well which vents in a grouping of fields (Sub-basin entity) within a Basin entity, require the calculation of the well-bore de-pressuring volume for a typical well-bore configuration and pressure for each unique producing horizon/formation. This calculated volume would be applied to all wells producing from the unique producing horizon/formation in the Sub-basin entity. The reservoir flow component would be additive rather than on an individual well production rate basis, based on the total venting time of all wells producing from the unique producing horizon/formation and the average production rate of all wells producing from the unique producing horizon/formation. For wells which are completed in and producing from multiple producing horizons/formations, both the well-bore de-pressuring volume and the reservoir flow per unit of time would be assumed to be the higher rate established for the applicable producing horizons/formations being produced.

Response: EPA agrees with the commenter that use of a plunger lift changes the calculation of emissions for method #2. Today's final rule includes a third method for venting a well to the atmosphere with the aid of a plunger lift. In this calculation, the volume of gas in the tubing string above the plunger, at sales line pressure, is calculated for an average half-hour period to bring the plunger and liquid load to the surface. If the well is left open longer than this average half-hour, then the continued venting to the atmosphere is estimated at average sales flow rate. This is a cost-effective alternate to measuring this flow rate. EPA recognizes that the gas bubble accumulated in the well casing at shut-in pressure (which will occur gradually as liquids accumulation in the tubing string gradually stop gas flow to the sales line) will flow up the unimpeded tubing string to the atmosphere at a higher rate than normal flow to the sales line. However, this is very difficult to calculate costly to measure. Therefore, to adequately inform future policy, the average sales flow rate is something known for each well, and a conservative estimate for those cases where wells are left open longer than necessary to raise the plunger. For more information on this additional well liquids unloading method, please see EPA-HQ-OAR-2009-0923 "Change to Rule Equation W-7: Time to Vent the Casing Gas from Well Liquids Unloading."
Also, please see the comment EPA-HQ-OAR-2009-0923-1151-96 for a response to the commenter's cost estimates for monitoring well liquids unloading.

Comment Number: EPA-HQ-OAR-2009-0923-1151-119
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(g) Gas well venting during unconventional well completions and workovers

API appreciates EPA's provision of alternate methodologies for estimating emissions from flow-back and clean-up of wells following fracture stimulation during initial completion and subsequent work-over and urges EPA to retain this flexibility. However, we believe that the methodologies described by EPA in the proposed rule are unnecessarily complex, burdensome and can be significantly improved while still yielding high quality data. As structured in the proposed rule, operators are required to use one of two methods to determine completion and work-over venting or flaring emissions. For clarity, each method and alternative is discussed separately.

Method #1 As Proposed by EPA: This method requires that operators measure the flow rate from one completion event and one work-over event in “each gas producing field” (presumed to be a named field as identified in the EIA’s field list referenced in the proposed rule) and then apply the flow rate to all other completions and work-over’s on a flow-back time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields) API estimates a total of 7,072 completion event measurements and 3,929 work-over event measurements would be required. This would be followed by tracking flow-back time for each of some 39,000 completion and work-over events and then calculating emissions. API estimates a total cost of $15.0 million to uniformly implement the Method #1 requirements which would be fully repeated every two years with a lower burden and cost in the interim years between measurements.

Method #2 As Proposed by EPA: This method requires that operators estimate the flow rate from one completion event and one work-over event in “each gas producing field” (presumed to be a named field as identified in the EIA’s field list referenced in the proposed rule) by measuring the pressure drop across a choke and then performing a choke-flow calculation to arrive at an average flow-rate. This rate would then be applied to all other completions and work-overs on a flow-back time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields) API estimates a total of 7,072 completion event estimates and 3,929 work-over event estimates would be required. This would be followed by tracking flow-back time for each of some 39,000 completion and work-over events and then calculating emissions. API estimates a total cost of $9.5 million to uniformly implement the Method #2 requirements which would be fully repeated every two years with a lower burden and cost in the interim years between measurements.

To address the problems outlined for EPA’s proposed Methods 1 and 2, API suggests the following alternative:

Alternative Method Proposed by API: Rather than requiring completion and work-over estimates for each field, require them for field groupings in a particular basin (Sub-basin entity) on a producing horizon/formation specific basis. In a producing area the reservoir characteristics and behavior from a particular producing horizon/formation tends to be quite uniform and operators tend to use the same or very similar hydraulic fracture and well clean-up techniques and practices. Although the reduction in burden is difficult to forecast it could be substantial when compared against the proposed EPA methodology.

API also requests that EPA clarify what type of events are within the scope of coverage for this category, particularly for work-overs. It is not clear what well work events classify as “workovers" subject to the requirements of the rule. Section 98.233 (g) "Gas well venting during unconventional well completions and work-overs" appears to limit the calculation of emissions to well clean-up post hydraulic fracturing operations with the following language: "Calculate emissions from gas unconventional well venting during well completions and work-overs from hydraulic fracturing". Other down-hole well work, such as tubing changes, maintenance, etc, do not appear to be covered. API agrees with EPA that the proper focus is on the high rate flow-back following fracture stimulation but requests that this be made clearer in the rule.

The rule also needs to make provision for incorporating the flow back of energizing gas used in "energized fracs". The two typical gases used in energized fracs are nitrogen and carbon dioxide. When a well is flowed for clean-up following an energized frac, the energizing gas will be the majority of the gas component flowed back during the initial stages of clean-up. Most/all of the energizing gas is recovered from the formation during clean-up and is flared or vented. This gas is purchased by weight and the quantity is known. API recommends that EPA include a provision in Section 98.233 (g) which attributes the appropriate portion of the flow from a well clean-up following an energized frac to the energizing gas used. In the case of nitrogen it would be subtracted from the total measured or calculated flow. In the case of carbon dioxide, the portion equal to the amount of gas pumped would be subtracted from the total flow and evaluated as pure carbon dioxide rather than the typical well stream gas mixture.

Response: EPA disagrees with the commenter. With regard to methodologies for estimating emissions from gas well venting during well completions and workovers with hydraulic fracturing, please see the response to EPA-HQ-OAR-2009-0923-1305-46.

Also, please see the comment EPA-HQ-OAR-2009-0923-1151-97 for a response to the commenter's cost estimates for monitoring well venting from completions and workovers with hydraulic fracturing.

Comment Number: EPA-HQ-OAR-2009-0923-1151-120
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(h) Gas well venting during conventional well completions.

Onshore Production Source Category: Gas well venting during conventional well completions

Section 98.233 (h) requires calculating emissions from each gas well venting during conventional well completions and workovers based on the daily gas production rate and cumulative amount of time each well is venting during the year.

For "new" wells, which have not established a production rate, the rule should allow the use of the average flow rate from the first 30 days of production.

Response: EPA agrees with this comment and is now allowing in today's final rule the use of the average flow rate from the first 30 days of production for new wells. In the event that the new well is completed less than 30 days from the end of the reporting period, the first 30 days of production straddling the current and following reporting years shall be used.

Comment Number: EPA-HQ-OAR-2009-0923-1151-122
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(l) Well testing venting and flaring

Onshore Production Source Category: Well testing venting and flaring

Section 98.233(l) requires determining the gas to oil ratio (GOR) of the hydrocarbon production for each well tested, determining the flow rate of oil for the well being tested, and tracking the number of days in the year that the well is tested.
The vast majority of well tests are conducted while the wells are in operation and do not require venting or flaring. As a result, the rule should exempt well testing that does not result in venting or flaring natural gas.

Response: In response to the commenters concerns on well testing and flaring of natural gas, the source monitoring method description in the supplementary proposed rule sufficiently clarifies that the emissions are to be reported only when there is venting or flaring.

Comment Number: EPA-HQ-OAR-2009-0923-1151-34
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(f)(1)(ii) Well venting for liquids unloading . API suggests that it would be appropriate to include the use of API Compendium Equation 5-28 as an alternative to Equation W-7.

$$E_{CH_4 \text{ or } CO_2} = (9.781\times10^{-7})\times\left(\frac{1}{z}\right)\times(D_{casing})^2\times(\text{Depth})\times(P)\times(CH_4 \text{ or } CO_2 \text{ mole fraction})$$
$$\times(MW_{CH_4 \text{ or } CO_2})\times\left(\frac{\#\ \text{Blowdowns}}{\text{Year}}\right)\times\frac{\text{tonnes}}{2204.62\ \text{lb}}$$

E [subscript CH_4 or CO_2] = (9.78 x 10^-7) x (1 / Z) x (D [subscript casing])^2 (P) x (CH_4 or CO_2 mole fraction) x (MW [subscript CH_4 or CO_2]) x (# blowdowns / year) x (tones / 2204.62 lb)
Response: EPA disagrees that the commenter proposed equation adequately accounts for well venting for liquids unloading. This equation is basically the same concept as that proposed in today's final rule for well venting without the aid of a plunger lift, with the exception of the venting time element. EPA has determined from Gas STAR partner feedback that liquids unloading without the aid of a plunger lift is very inefficient, increasingly so with lower shut-in pressure. Because of this inefficiency, it is possible that well operators may leave the vent valve open for a longer time that that necessary to just exhaust the gas bubble in the well casing at shut-in pressure. Therefore, in today's final rule, in addition to the option of metering the gas vent, EPA is providing two equations for liquid unloading venting to the atmosphere, each

including a time element: one equation without a plunger lift and one with the aid of a plunger lift.

Comment Number: EPA-HQ-OAR-2009-0923-1155-20
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

<u>Comment Excerpt Text:</u>
Well Venting

Due to the dramatic under-reporting of well venting emissions, as described in Section 2 of our comment above, and the profitable opportunity to collect emissions at a sizable profit (e.g. "Green Completions" or "Reduced Emissions Completions (REC)", we recommend that EPA require Operators to meter vented gas volume at each well.

We recognize that there are some cases where it may not be technically feasible to implement a green completion. For example, well pressure may be too low or pipeline infrastructure may not yet be installed (e.g. exploratory drilling or the first well on a well site). Gas pipelines are typically not installed until it is confirmed that an economic gas supply is found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline in place. However, subsequent wells drilled on that same pad would be in a position to implement green completion techniques. In these limited cases, we would support EPA's proposed well venting emission estimating methods that are formation specific (field horizon) and based on tubing size, flow rate and venting duration, with three important modifications. We agree with WCI's recommendation that the frequency of the sampling and metering should be increased to obtain representative data for wells where reservoir or well conditions are unique.

EPA proposes that one representative well completion and one representative well workover per field horizon be developed to characterize daily venting emissions from all other completions and workovers within a given field horizon. A single well measurement, however, may not be representative of the entire field and therefore a more statistically robust sample size (e.g., 3-5 wells, or 5% of wells, etc.) should be adopted. EPA proposes that this field level well venting emission factor be updated once every two years.

We agree with WCI's recommendation that the frequency of the sampling and metering should be increased to obtain representative data for wells where reservoir or well conditions are unique. We recommend that the emission factor be updated annually, because well flowrates can vary substantially over time.

For unconventional wells (e.g., hydraulically fractured wells), if the fracturing is typically done in multiple stages and is in fact not a continuous process, then measuring the emissions in units of "days of venting" may not be as good as requiring measurement in units of " hours of venting". EPA should consider requiring reporting in the most representative units of time.

Response: EPA notes the commenter's position in regard to reduced emissions completions and has retained the option to use a meter for estimating emissions. However, a vast majority of the wells are still not completed using reduced emissions completions and hence EPA has retained the option to use a choke calculation to estimate emissions.

EPA notes the commenter's concern on accuracy of monitoring methods and the need for stringent quality requirements but EPA does not agree with the commenter. With regards to accuracy of monitoring methods, please see the response to EPA-HQ-OAR-2009-0923-0582-25.

With regards to the comment on the units of time, EPA does not see this as an issue. Hour units can be converted to day units by dividing the total hours by 24. EPA has used units that are most convenient to most of the reporters.

Comment Number: EPA-HQ-OAR-2009-0923-1167-32
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:

Gas well venting during unconventional well completions and workovers: Noble supports the API comment regarding gas well venting during unconventional well completions and workovers. Additionally, Noble requests, as proposed by API, the flexibility of allowing the completion and work-over measurements (Method #1) or estimates (Method #2) to be completed for an even larger grouping. This grouping could be multiple producing horizons/formations, rather than a single producing horizon/formation, if the reservoir characteristics and behavior from the group of horizons/formations tend to be quite uniform and operators tend to use the same or very similar hydraulic fracture and well clean-up techniques and practices.

Response: EPA disagrees with the commenter. With regards to well completion and workover groupings, please see the response to EPA-HQ-OAR-2009-0923-1151-19.

Comment Number: EPA-HQ-OAR-2009-0923-1201-12
Organization: North Slope Burough
Commenter: Edward S. Itta

Comment Excerpt Text:
Gas well completions and well workovers.

As previously noted, emissions from well completions (based on industry experience as reported through EPA's Natural Gas STAR program) are probably significantly underestimated[194] in each unique field. In fact, the emissions factor being used in the 2008 U.S. GHG Inventory is

[194] See also 75 FR 18621: [N]o body of data has been identified that can be summarized into generally applicable emissions factors to characterize emissions from these sources [(i.e., from well completion venting and well workover venting).

believed to significantly underestimate emissions based on industry experience as included in the EPA Natural Gas STAR Program publicly available information (http://www.epa.gov/gasstar/). In addition, the 2008 U.S. GHG Inventory emissions factor was developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country.] The 2008 U.S. GHG Inventory emphatically states that "[n]atural gas well venting due to unconventional well completions and workovers, as well as conventional gas well blowdowns to unload liquids have already been identified as sources for which Natural Gas STAR reported reductions are significantly larger than the estimated inventory emissions."[195] And EPA has again indicated, in response to questions from Environmental Defense Fund, that "[p]resently, [reduced emission completions (REC)] reductions reported in the Natural Gas STAR body of work is larger than well completion venting in the inventory on an annual basis."[196] Specifically, the U.S. GHG Inventory is based on an emission factor of a little over three thousand standard cubic feet (3 Mcf) per gas well drilled and completed.[197]

Yet Natural Gas STAR program partner experience shows several cases where emission factors were thousands of times higher than those shown in the 2008 inventory. Examples include (1) a BP project employing green completions at 106 wells and reporting 3,300 Mcf of gas recovered per well[198] (2) a Devon Barnett Shale project employing green completions at 1,798 wells between 2005 and 2008 and reporting 6,300 Mcf of gas recovery per well,[199] and (3) a Williams project employing green completions at 1,064 wells in the Piceance Basin reporting 23,000 Mcf of gas recovered per well.[200]

All of these examples include gas recovery estimates more than 1,000 times higher than the 3 Mcf of gas per well estimated in the U.S. GHG Inventory for 2008.
These data are consistent with the unconventional gas well completion and workover data presented in EPA's TSD. Specifically, Appendix B on pp. 79-82 includes four examples from the Natural Gas STAR program with gas completion rates of 6,000 Mcf, 10,000 Mcf, 700 Mcf

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[195] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, p. 3-47.

[196] See "Environmental Defense Fund (EDF) Questions & USEPA Answers – June 1, 2010" posted to the Docket for this action on June 2, 1010, Docket ID EPA-HQ-OAR-2009-0923-0070.

[197] Table A- 118: 2008 Data and CH4 Emissions (Mg) for the Natural Gas Production Stage, p. A-144, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006.

[198] See Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/green_c.pdf, slide 11.

[199] See Attachment B, 2009 workshop presentation by Devon, slides 3 and 13. 6,300 Mcf = 11.4 Bcf / 1,798 wells.

[200] See Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/workshops/pennstate2009/robinson1.pdf, slide 16. NOTE: the reported Williams reductions appear to assume an average of 32 days of uncontrolled venting during flowback, which seems like an unreasonably long length of time.

and 20,000 Mcf per completion. EPA used an average of these four data points for its emission factor for this source (i.e., 9,175 Mcf/completion). Using this factor resulted in estimated emissions from completions of conventional and unconventional wells of 86 billion standard cubic feet (Bcf). By comparison, the U.S. GHG Inventory reports emissions of just 0.1 Bcf of gas from drilling and well completions.[201.202]

More generally, Natural Gas STAR partners reported recovering between 7 and 12,500 Mcf (average of 3,000 Mcf) of natural gas from each cleanup with the potential for an estimated 25 Bcf of natural gas recovery from green completions annually in 2005, compared with the annual U.S. GHG Inventory total for "Drilling and Well Completion" of just 0.1 Bcf in 2008. And more recently, EPA's Natural Gas STAR program attributed 45 Bcf of gas to reduced emissions completions (RECs) in 2008 (representing 50 percent of EPA's Natural Gas STAR program's annual total reductions).[203] If, in fact, the emission factor for well completions is at least 1,000 times higher than what is reported in the U.S. GHG Inventory (e.g., if it is at least 3,000 Mcf instead of 3 Mcf), this adds 100 Bcf to the total estimated emissions from natural gas systems—raising the total from 240 Bcf to 340 Bcf in 2008 (a 40% increase).[204]

A New York Times article published on October 15, 2009, reports that EPA is currently reviewing and revising methane emissions from U.S. gas wells[205]
According to the article:

An E.P.A. review of methane emissions from gas wells in the United States strongly implies that all of these figures may be too low. In its analysis, the E.P.A. concluded that the amount emitted by routine operations at gas wells — not including leaks like those seen near Franklin — is 12 times the agency's longtime estimate of nine billion cubic feet. In heat-trapping potential, that new estimate equals the carbon dioxide emitted annually by eight million cars.[206]

In fact, the TSD for the MRR includes an estimate of 120 Bcf for U.S. well completion and

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[201] See http://www.epa.gov/gasstar/documents/green_c.pdf, slides 9 and 5; Table A-125: CH4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg.

[202] See Table A-125: CH4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg. (2.05 Gg * 0.052 ft3/g = 0.1 Bcf).

[203] See 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50% are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[204] See Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-38 CH4 Emissions from Natural Gas Systems (Gg), p. 3-45. Total emissions in Bcf: 4,591 Gg * 0.052 ft3/g = 240 Bcf.

[205] See www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html#.

[206] See www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html#.

workover venting[207] As previously discussed, this estimate is based on an emission factor of 9,175 Mcf per completion or workover. Given the sparse data (4 data points) and the enormously wide range of potential emission factor values from this source (ranging from 700 to 20,000 Mcf), even the recently revised estimates may very well continue to underestimate emissions from this source.

The statistical representation of the U.S. GHG Inventory data includes a 95 percent certainty range within which emissions from this source category are likely to fall for the year 2008. This range, for Natural Gas Systems, includes a lower bound of -24% and an upper bound of +43%.[208] As noted in the uncertainty analysis, "[t]he heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry."[209] Basing an emission factor on only a few "representative" sources with highly variable rates results in a potentially high degree of uncertainty, as reflected in the reported uncertainty range.

The EPA-acknowledged discrepancies between the inventory emissions reported to-date and the Natural Gas STAR-reported reductions (and the high degree of uncertainty in both of these data sources) demonstrate the need for more reliability in emissions reporting from the oil and gas sector.

The Large and Growing Number of Oil and Gas Sources Means Continuous Improvement is Necessary to Minimize Uncertainty in the Reported Data.

Certain oil and gas sources are of particular importance due to the magnitude of their emissions. These sources will require the best possible reporting requirements if the data gathered are to be representative and of further use. In particular, uncertainties in data reported across a large population of sources (e.g., the hundreds of thousands of pneumatic devices used throughout the oil and gas sector) have the potential to greatly reduce the value of the dataset. Pneumatic devices are a prime example of a source that is particularly important in terms of magnitude and is also important due to the sheer number of individual sources, each one with uncertain levels of emissions. The magnitude and importance of this emissions source support a greater emphasis on direct measurement (e.g., metering) and on rigorous verification and audit for any reporting that will be based on engineering estimates (e.g., OEM emission factors).

Response: EPA agrees with the commenter that certain sources, such as well venting, are underestimated in the national inventory. EPA has where possible balanced between cost to report and the need for better quality data. In the case of well liquids unloading, well completions, and well workovers EPA has retained the monitoring methods proposed. However, for pneumatic devices, considering the costs to monitor high bleed devices and pneumatic

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[207] See TSD at 82.

[208] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-41, p. 3-46.

[209] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3-46.

pumps, EPA has required the use of emissions factors in today's final rule. See major changes in the rule in Section II.F of the preamble to today's final rule for more details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-35
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Gas well venting during unconventional well completions and workovers & Gas well venting during conventional well completions and workovers

Section 98.233(g) & (h): EPA provides two calculation methodologies for unconventional wells and one calculation methodology available for conventional wells. For the purposes of calculating GHG emissions under Subpart W, there is no valid reason to make a distinction between "conventional" and "unconventional" wells. IPAMS requests that EPA make available all three calculation methodologies for all well completions and workovers, regardless of whether the well is considered "conventional" or "unconventional."

Response: EPA disagrees with the commenter. With regards to making all three calculation methodologies available to conventional and unconventional wells, please see the response to EPA-HQ-OAR-2009-0923-1040-20.

Comment Number: EPA-HQ-OAR-2009-0923-1305-20
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(g) Gas well venting during unconventional well completions and workovers and (h) Gas well venting during conventional well completions and workovers

For the well completion emissions, the rule does not seem to specifically address green completions and how these are to be handled. The rule should be clarified to only include flow which is emitted to atmosphere or flared.

Response: EPA agrees with the commenter. In today's final rule, EPA allows for adjustments for completion and workover hydrocarbons being sent to a flare.

Comment Number: EPA-HQ-OAR-2009-0923-1305-46
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(f) Well venting for liquids unloading.

BP appreciates EPA's provision of alternate methodologies for estimating emissions from venting of gas wells to unload liquids and urges EPA to retain both options. However, we believe that the methodologies described by EPA in the proposed rule are unnecessarily complex, burdensome and can be significantly improved while still yielding high quality data. As structured in the proposed rule, operators are required to use one of two methods to determine venting emissions. For clarity, each method and alternative is discussed separately.

Method #1 As Proposed by EPA: This method requires that operators measure emissions from one vent per "unique well tubing diameter and producing horizon/formation combination in each gas producing field" (presumed to be a named field as identified in the EIA's field list referenced in the proposed rule) and then apply the venting rate to all other wells in the same "unique combination" on a venting time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields), a large number of unique venting measurements would be required to encompass the unique combinations of fields, producing horizons/formations, and tubing diameters. At a projected cost of $1,000 per measurement, for temporary piping modifications, installation of a temporary recording flow-meter, conducting the measurements, and returning the piping to its original configuration, the burden and cost of measurement would be significant. To address this problem, BP suggests the following:

Method #1 Alternative as Proposed by BP: Rather than requiring venting measurements for each field, require them for field groupings in a particular basin (Sub-basin entity) on a producing horizon/formation specific basis with no distinction for different tubing sizes. In a producing area, the production from a particular producing horizon/formation tends to be quite uniform and operators tend to use the same or very similar tubing sizes. Also, the venting rate is much more dependent on the producing horizon/formation pressure and reservoir flow dynamics along with the flowing operating pressures (determined by the collection system pressures which tend to be uniform) than the tubing size. Operators would establish a venting rate, based on the measurements, for each sub-basin entity and then track the total venting time on a producing horizon/formation basis to arrive at an emissions estimate for sub-basin entity. For wells which are completed in and producing from multiple producing horizons/formations, the venting rate would be assumed to be the higher rate established for the applicable producing horizons/formations being produced. Although the reduction in burden is difficult to forecast it would be substantial when compared against the proposed methodology.

Method #2 As Proposed by EPA: Method #2 requires calculation of the "blow-down" volume from de-pressuring each individual well-bore and then adding the reservoir flow component based on time and the individual well's production rate. This requires tracking, at an individual well level, the number and time of each individual venting event. With the large number of gas wells subject to the rule a very large number of individual well-bore de-pressuring calculations would be required. This would be followed by tracking of a much larger number of discrete venting instances per year in order to calculate emissions.

Method #2 Alternative as Proposed by BP: Rather than requiring the calculation of the wellbore de-pressuring volume for each individual well which vents, in a grouping of fields (Reporting Unit/Area) within a basin require the calculation of the well-bore de-pressuring volume for a typical well-bore configuration and pressure for each unique producing horizon/formation. This calculated volume would be applied to all wells producing from the unique producing horizon/formation in the Reporting Unit/Area. The reservoir flow component would be added based on the total venting time of all wells producing from the unique producing horizon/formation and the average production rate of all wells producing from the unique producing horizon/formation rather than on an individual well production rate basis. For wells which are completed in and producing from multiple producing horizons/formations, both the well-bore de-pressuring volume and the reservoir flow per unit of time would be assumed to be the higher rate established for the applicable producing horizons/formations being produced.

E. Section 98.233(h) Gas well venting during conventional well completions.

Section 98.233 (h) requires calculating emissions from each gas well venting during conventional well completions and workovers based on the daily gas production rate and cumulative amount of time each well is venting during the year.

For “new” wells, which have not established a production rate, the rule should allow the use of the average flow rate from the first 30 days of production.
F. Section 98.233(g) Gas well venting during unconventional well completions and workovers

BP appreciates EPA’s provision of alternate methodologies for estimating emissions from flowback and clean-up of wells following fracture stimulation during initial completion and subsequent work-over and urges EPA to retain this flexibility. However, we believe that the methodologies described by EPA in the proposed rule are unnecessarily complex, burdensome and can be significantly improved while still yielding high quality data. As structured in the proposed rule, operators are required to use one of two methods to determine completion and work-over venting or flaring emissions. For clarity, each method and alternative is discussed separately.

BP also requests that EPA clarify what type of events are within the scope of coverage for this category, particularly for work-overs. It is not clear what well work events classify as “workovers” subject to the requirements of the rule. Section 98.233 (g) “Gas well venting during unconventional well completions and workovers” appears to limit the calculation of emissions to well clean-up post hydraulic fracturing operations with the following language: “Calculate emissions from gas unconventional well venting during well completions and workovers from hydraulic fracturing”. Other down-hole well work, such as tubing changes, maintenance, etc, do not appear to be covered. BP agrees with EPA that the proper focus is on the high rate flow-back following fracture stimulation but requests that this be made clearer in the rule.
The rule also needs to make provision for incorporating the flow back of energizing gas used in “energized fracs” to assist with post frac clean-up. The two typical gasses used in energized fracs are nitrogen and carbon dioxide. When a well is flowed for clean-up following an energized frac, the energizing gas will be the majority of the gas component flowed back during the initial stages of clean-up. Most/all of the energizing gas is recovered from the formation during clean-up and is vented to atmosphere (either while flaring or directly venting). This gas is purchased by weight and the quantity is known. BP recommends that EPA include a provision in 98.233 (g) which attributes the appropriate portion of the measured or calculated flow from a well clean-up following an energized frac to the energizing gas used. In the case of nitrogen it would be subtracted from the total measured or calculated flow. In the case of carbon dioxide, the portion

equal to the amount of gas pumped would be subtracted from the total measured or calculated flow and evaluated as pure carbon dioxide rather than the typical well stream gas mixture.

Method #1 As Proposed by EPA: This method requires that operators measure the flow rate from one completion event and one work-over event in “each gas producing field” (presumed to be a named field as identified in the EIA’s field list referenced in the proposed rule) and then apply the flow rate to all other completions and work-over’s on a flow-back time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields) this would require a large number of measurements be made initially and then repeated every two years. To address this problem, BP suggests the following:

Method #1 Alternative as Proposed by BP: Rather than requiring completion and work-over measurements for each field require them for field groupings in a particular basin (Reporting Units/Areas) on a producing horizon/formation specific basis. In a producing area the reservoir characteristics and behavior from a particular producing horizon/formation tends to be quite uniform and operators tend to use the same or very similar hydraulic fracture and well clean-up techniques and practices. Although the reduction in burden is difficult to forecast it would be substantial when compared against the proposed methodology.

Method #2 As Proposed by EPA: This method requires that operators estimate the flow rate from one completion event and one work-over event in “each gas producing field” (presumed to be a named field as identified in the EIA’s field list referenced in the proposed rule) by measuring the pressure drop across a choke and then performing a choke-flow calculation to arrive at an average flow-rate. This rate would then be applied to all other completions and work-overs on a flow-back time basis. Due to the large number of onshore gas fields (estimated as 15,715 covered fields) this would require a large number of measurements be made initially and then repeated every two years. To address this problem, BP suggests the following:

Method #2 Alternative as Proposed by API: Rather than requiring completion and work-over estimates for each field require them for field groupings in a particular basin (Reporting Units/Areas) on a producing horizon/formation specific basis. In a producing area the reservoir characteristics and behavior from a particular producing horizon/formation tends to be quite uniform and operators tend to use the same or very similar hydraulic fracture and well clean-up techniques and practices. Although the reduction in burden is difficult to forecast it would be substantial when compared against the proposed methodology.

Response: In developing the petroleum and natural gas onshore production segment, EPA considered many alternative facility definitions, ranging from potential groupings of wells connected to gathering stations, to fields, to basins, all with one principle in mind: provide a definitive definition that all producers can directly apply without arbitrary or arcane discretion. Fields are defined and catalogued, as are basins. Any sub-basin grouping of fields by various combinations of similarities in production quality, oil gravity, gas to oil ratio, shut-in pressure, formation permeability and porosity, age and location would be significantly less than definitive, and therefore, EPA retained the basin definition for onshore production facilities.
The option of methods #1 and #2 provided by EPA are both practical and cost-effective. Method #2 is more cost effective, and requires simply well and field data that is readily available and

easy to analyze to determine well liquids unloading venting, provided the time of venting is collected and retained. Where well venting is performed with a fixed timer plunger lift, the venting time is a matter of noting the timer setting and manual changes in timer setting. For advanced programmable logic controller optimized cycle venting, the PLC can be programmed to retain the number and duration of venting events. For manual venting to the atmosphere, it is incumbent on the operator to log the event and time between opening and closing the vent to atmosphere. As noted by this commenter, in EPA provided method #2 , "the total venting time of all wells producing from a unique producing horizon/formation" is a part of the equation for extended venting at average well production rate. Therefore, this data contemplated by the commenter as a component of the venting calculation, only on a field basis in today's final rule rather than an undefined combination of fields. Therefore, in developing the petroleum and natural gas onshore production segment EPA decided against any reporter developed combinations of fields within a basin as a basis for emissions calculation methods. EPA also disagrees with the commenter that the reporting from well liquids unloading sources is burdensome; please see response to EPA-HQ-OAR-2009-0923-1151-96 for further details. EPA agrees and is now allowing in today's final rule the use of the average flow rate from the first 30 days of production for new wells. For further information, see response to comment EPA-HQ-OAR-2009-0923-1151-120.

For changes to the methodology for well completions and workovers in today's final rule please see the response to comment EPA-HQ-OAR-2009-0923-1011-11. EPA has determined that the monitoring of well completions and workovers with hydraulic fracturing per the supplementary proposed rule methods is not significantly burdensome. Please see response to EPA-HQ-OAR-2009-0923-1151-97 for details on how the number of samples required for monitoring well completions and workovers with hydraulic fracturing is manageable for all reporters. Since the burden to report is manageable and grouping of fields is not required, EPA has retained the monitoring methods for well completion and workovers.

In today's final rule, EPA has revised the source type name for well workovers based on whether or not there is a fracturing involved. Well workovers that do not require fracturing use a simple emissions factor.

EPA agrees that energized fracs are emerging, and affect the quantity of GHG emissions (methane and CO_2, depending on whether they are CO_2 gas assist or nitrogen gas assist). Today's final rule includes an adjustment of the vented GHG emissions for gas composition as determined by sample analysis, available gas composition data or, in the specific case of gas well completions with energized hydraulic fracturing, a material balance based on accounting for the energized gas fraction of the total gas emissions.

13.2.2 TANK EMISSIONS

Comment Number: EPA-HQ-OAR-2009-0923-1061-10
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:

10. De minimis thresholds should be added to the modeling requirements in § 98.233(j) and the direct measurement requirements in § 98.233(k), and subjections (j) and (k) should be revised. Section 98.233(j) would require emissions modeling from production and processing storage tanks, while § 98.233(k) would require direct measurement of emissions from transmission storage tanks. There is no reason to subject de minimis emission sources to the onerous and costly reporting requirements that would be required by §§ 98.233(j) and (k). The rule should be modified so that the requirements of subparagraph (j) and (k) would not apply unless the tank at issue met a 5 bbl/day threshold for throughput of hydrocarbon condensate.[210]

In addition, owners or operators of components that are required to meet the requirements of subparagraph (j) should be able to use HySYS or Promax as an alternative to E&P Tank:. These technologies are at least as sophisticated as E&P Tank: and are widely recognized and accepted in the industry. As such they should be available as alternatives. Similarly, the list of specific data parameters in subparagraph (j)(I) should be modified to allow operators to select the appropriate representative data for whichever authorized software package they employ.

Proposed § 98.233(k)(2) would require direct measurement if a stuck dump valve was detected at a transmission storage tank. This requirement should be eliminated, even if other direct measurement requirements are retained. A stuck dump valve is a malfunction that, when discovered, will quickly be repaired. It is akin to a leak along a pipeline, which as EPA states will quickly be repaired and, as a result, is not subjected to Subpart W at all. There is no reason to impose a metering requirement on a malfunction that when discovered will be fixed promptly. Indeed, the ironic result of the rule in its current state would be that such immediate repairs could not be made - because the leak would have to be measured before it was fixed. This makes no sense and is contrary to the purpose of the environmental laws in general, which is to reduce emissions rather than exacerbate them.

Response: EPA agrees that onshore production storage tanks with a throughput below a certain equipment threshold should be given relief from using complex process models and simulations to determine GHG emissions. Hence, EPA has set an equipment threshold at 10 barrels per day that would result in approximately 18% of tanks to report emissions using a software program and 82% of tanks to report emissions using an emission factor. EPA's selected equipment threshold is more conservative than the commenter's recommended 5 barrel per day equipment threshold. Please see the memo "Equipment Threshold for Tanks" in the rulemaking docket

[210] TPA's preference is that any direct measurement requirements in the rule (such as in § 98.233(k) be eliminated altogether.

(EPA-HQ-OAR-2009-0923) for how EPA determined this threshold. , EPA determined that setting an equipment threshold of 10 barrels per day of separator throughput, such that any tank connected to a separator below the equipment threshold use a simple emissions factor approach, would result in significant reduction in burden without significantly compromising emissions data reporting quality.

EPA reviewed the comment related to setting an equipment threshold on transmission storage tanks and disagree that a threshold is necessary. There are relatively fewer storage tanks in the transmission segment; as low as one or two tanks per compressor station. In addition, operators or owners of transmission storage tanks will only have to conduct direct measurement and report emissions if continuous emissions are detected from the vapor vent stacks using an optical gas imaging instrument. EPA through its Natural Gas STAR Program has determined that malfunctioning dump valves can be a source of significant emissions through liquid tanks. Hence, given the low burden and importance of characterizing this source of emissions, EPA has retained the requirements for transmission storage tanks. The information gathered through this requirement will help EPA characterize the frequency of such occurrences in the industry to suitably inform policy .

EPA's intent in requiring the use of E&P Tank in the rule was to standardize the calculation methods across reporters. However, EPA notes the prevalence of other process simulators and modeling tools in use in the industry and understands that there is some equivalency in their modeling capabilities. Hence, in today's final rule, EPA does not prescribe E&P Tank or any other specific process simulator. Instead, EPA allows the use of any process simulators that meets the requirements under Calculating GHG emissions – Onshore production and processing storage tanks.

EPA disagrees with the commenter that monitoring of stuck dump valves should be removed. EPA agrees that stuck dump valves are usually repaired upon detection and the rule does not preclude operators from fixing the malfunctioning valves. Specifically, if a scrubber dump valve is found malfunctioning during standard operations at a time other than the official leak survey, nothing in the rule states that the reporter must not fix the dump valve or take a measurement. The only time when a measurement must be taken is if a scrubber dump valve is found leaking during an official leak survey. However, prior to detection, these stuck dump valves are emitting gas, which could be significant source of emissions for some facilities. EPA recognizes that the dump valve will remain open during the monitoring but this is needed to accurately estimate the emissions. In fact, EPA contends that such malfunction will not be widespread in facilities where the current maintenance practices result in minimal occurrences of such malfunctions, and should be no cause for concern. Finally, EPA has provided the option of using acoustic leak detection and measurement devices that can quickly detect and measure leaks without the need for more burdensome and time consuming direct measurement approach. This should mitigate any concerns on the emissions from dump valves due to the monitoring requirements set forth in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1298-71
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Process Simulators: In some cases the rule allows the use of simulation software packages; however, because the exact software package is specified [such as GRI GLYCalc in Section 98.233(e) and API E&P TANK in Section 98.233(j)], suitable alternatives are excluded. There are other commercially available, industry-accepted process simulators that are as accurate as (or more so) than the prescribed software packages (e.g., HYSYS, ProMax, PRO/II, PROSIM, etc.). In addition, these process simulators can be used for source categories that do not currently have simulation software packages recommended in the rule (e.g., AGR vents). IPAMS requests that EPA not specify the simulation software package for each source category, and instead allow all commercially available, industry-accepted process simulators.

Response: EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks. Please see the response to EPA-HQ-OAR-2009-0923-1061-10 for further details. EPA agrees with the commenter on the use of process simulation software program for AGR vent. Please see the response to EPA-HQ-OAR-2009-0923-1024-26 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0053-4
Organization: Cardinal Engineering, Inc.
Commenter: Kristine D. Baranski

Comment Excerpt Text:
The proposed rule only allows for the use of GRI GLYCalc and E&P Tanks. Other commonly used modeling programs include HYSYS, Vasquez Beggs Equations, and process modeling software. Please consider allowing data from these more sophisticated programs.

Response: EPA is allowing the use of alternate process simulators to estimate emissions from onshore tanks and dehydrators. Please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EMAIL-0002-11 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
Additional engineering estimation methods should be included.

EPA has specifically identified two process simulation models in the proposed Subpart W, GRI-GLYCalc for estimating dehydrator emissions and E&P Tanks for estimating production and processing tank emissions. Many companies use more sophisticated process simulation models for some facilities to estimate emissions from tanks and acid gas removal units (AGR unit). The two most common are AspenTech's HYSYS process simulator and Bryan Research and Engineering's ProMax process simulator. These process simulators are widely accepted as the gold standards for detailed process design and optimization in the gas processing, chemical and refining industries.

Response: EPA is allowing the use of alternate process simulators to estimate emissions from onshore production. Please see the response to EPA-HQ-OAR-2009-0923-1061-10 for further details.

EPA is allowing the use of alternate process simulators to estimate emissions from dehydrator vent; please see the response to EPA-HQ-OAR-2009-0923-0053-4.

Comment Number: EMAIL-0002-5 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:

Minimum thresholds should be applied for equipment level applicability and calculations.

The EPA does not incorporate thresholds for applicability or for using simplified calculations at the equipment level. As a result, in many cases complex process models and simulations are required for equipment with minimal GHG emissions.

The first example is related to tanks, for which the same annual calculation method is prescribed regardless of the tanks throughput, for example a tank that fills at a rate of 1 barrel/day versus a tank that fills at a rate of 100 barrels/day. In this particular example, the prescribed method requires analysis of the separator liquid and collection of numerous operating parameters. The liquid analysis is expensive and often the sample is difficult or impossible to collect, even with higher liquid production rates, and should not be required for tanks with minimal throughput. Across the natural gas industry, there are thousands of tanks associated with very low liquid production rates and, therefore, minimal GHG emissions. GPA recommends that tanks with a throughput of less than 5 barrels/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, GPA recommends tanks below the 5 barrel/day threshold be allowed to use the appropriate emission factor from the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Gas Industry (API Compendium) in place of conducting modeling using process simulations.

Response: EPA agrees that determining input parameters that require sampling of low-pressure separator oil is difficult and burdensome. In today's final rule, EPA has provided alternate methods to determine parameters that require direct measurement of the low-pressure separator oil, namely the composition and Reid vapor pressure. These parameters can be determined using default values provided in some process simulators, previous analyses that are representative of the reporting facility, or direct measurement.
EPA agrees with the commenter's recommendation to include an equipment threshold for onshore production storage tanks and use of an emissions factor. Please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1009-6
Organization: Xcel Energy Inc.
Commenter: Eldon Lindt

Comment Excerpt Text:
The proposed rule does not contain emissions calculations for tanks that primarily contain water except for transmission station condensate tanks. The Preamble (pg. 18,621) requests comments on how to quantify emissions from transmissions tanks storing water without creating additional reporting burden. Xcel Energy requests that transmission station condensate tanks be excluded from reporting due to the de minimis nature of these emissions in the system. Quantification of emissions from transmission condensate tanks would be burdensome to reporters; the cost of required resources would far outweigh the benefit of this information.

Response: EPA disagrees that transmission station condensate tanks constitute a small emissions source and therefore should be eliminated from the rule. EPA recognizes that emissions from transmission storage tank condensate itself as a result of vapors flashing from the condensate and/or water is minimal. Rather, GHG emissions resulting from the gas blowing through a malfunctioning scrubber dump valve through a storage tank can be large and therefore it is EPA's intent to collect information on emissions from this source. As a result, operators or owners of transmission storage tanks will only have to conduct direct measurement if continuous emissions are detected from the vapor vent stacks using an optical gas imaging instrument or acoustic leak detection device; see response to EPA-HQ-OAR-2009-0923-1061-10 for further details. The monitoring methodology in today's final rule does not require the calculation of flashing losses, only emissions from leaking dump valves.

Comment Number: EPA-HQ-OAR-2009-0923-1082-13
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
EPA seeks comments on how to quantify emissions from tanks storing water without resulting in additional reporting burden to the facilities. (page 66)

MidAmerican submits that requiring the direct measurement of emissions from water storage tanks would be overly burdensome. There are proven analytical methods that are capable of calculating greenhouse gases released in storage tanks. However, it is crucial to differentiate between storage tanks for natural gas production and natural gas transmission.

Response: In regards to emissions from water tanks please see response to EPA-HQ-OAR-2009-0923-1305-40 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-40
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:

Water Storage Tanks

EPA seeks comments on how to quantify emissions from tanks storing water without resulting in additional reporting burden to the facilities.

BP supports EPA's stated goal of quantifying emissions without resulting in additional reporting burden and believes that EPA should not include quantification of emissions from tanks storing water in Subpart W. If EPA does choose to include this very small source, the default emission factors provided in the API Compendium for production and transmission condensate should be sufficient for providing a simple emission estimation method for this small source.

Response: EPA agrees with the commenter and has not required the estimation of emissions from water storage tanks in onshore production in today's final rule. However, tanks that store water/condensate in gas transmission segment are still required to report emissions; see response to EPA-HQ-OAR-2009-0923-1061-10 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1155-17
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Tank Emissions

We support WCI's recommendation that production and processing storage tank emissions be estimated using the gas-oil-ratio (GOR). The GOR measurement should be taken at a location immediately prior to the storage tank.

We strongly support EPA's proposed emissions reporting method for transmission storage tanks that uses an optical gas imaging device and gas metering.

Response: With regard to the WCI's recommendation, please see the response to EPA-HQ-OAR-2009-0923-0582-11.

13.2.2.1 ONSHORE PRODUCTION AND PROCESSING TANKS

Comment Number: EPA-HQ-OAR-2009-0923-1305-48
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(j) Storage tanks

BP supports EPA's selection of modeling as the methodology for determining emissions from Storage Tanks and supports the use of E&P Tanks as an applicable model. However, BP has several comments to clarify this category in the rule along with several proposals to broaden the methodologies available and to streamline the determination of GHG emissions from Storage Tanks thus significantly reducing the burden imposed by the proposed rule.

1. To clarify the scope of this source category, EPA should modify 98.233 (j) to apply only to storage tanks receiving produced hydrocarbon liquids rather than produced liquids as currently worded. All of the discussion in the preamble, the TSD, the calculation methodology in 98.233 (j), and the functionality of E&P Tanks apply only to hydrocarbon liquids. This clarification would make it clear that this source category does not encompass produced water tanks.
2. As proposed, the rule requires sampling and modeling of emissions from each individual separator dumping hydrocarbon liquids to a tank at atmospheric pressure. This presents a very large sampling, analysis, and modeling burden. Below, in these comments, BP presents alternatives to address the dilemma of applying the quantification requirements to each individual separator/tank combination.
3. As proposed, the rule restricts the selection of methods to modeling using E&P Tanks – latest software version. BP believes the allowable methodologies should be broadened as follows:
    a. Allow the use of E&P Tanks, Version 2 or higher as noted in 98.7.
    b. Allow the use of process simulation models, such as HySys, ProSim, etc. as alternatives to using E&P Tanks. These models are in wide use within the industry, are the “standard” for process design and optimization, and have much broader capabilities than E&P tanks.
    c. Allow the use of a “laboratory GOR” determination rather than modeling of separator tank combinations.
4. BP requests that EPA eliminate the “adjustment multiplier” provisions applied to the output of E&P Tanks as specified in 98.233 (j) (4). Based on the discussion of the derivation of these multipliers in the TSD, it appears that EPA is attempting to quantify abnormal equipment malfunctions of dump valves sticking and routing “raw” gas to the storage tank along with presumed “vortexing” of raw gas to the tank while dumping. The “adjustment multipliers” were apparently derived from examining a ratio of the output of E&P Tanks runs, using the GEO-RVP method, to measured emissions from the recent TCEQ tank study report. BP observes that the correlations of the same E&P Tank runs to the TCEQ data have very low correlation constants (0.0719 and 0.0045 for crude oil and condensate respectively) in the TSD discussion of how they were derived. Although no evaluation of the accuracy of the “adjustment multipliers” is presented in the TSD, it seems logical that they would share the same low correlation between the two methods and therefore have no basis. To compound this issue, as EPA is aware, there is substantial doubt, even within TCEQ, that the TCEQ study was conducted correctly and the data is suspect. As EPA observed in the TSD, equipment malfunction and vortexing have not yet been thoroughly studied or quantified, the sample data set is limited (and of dubious accuracy), and only very weak correlations were observed for the available data. BP also notes that the evaluation presented in the TSD was done using E&P Tanks in the GEO-RVP mode while the rule specifies running the simulation based on actual pressurized separator hydrocarbon liquid samples and conditions which further degrades any already dubious application of these “adjustment multipliers”.

In addition to the very weak information and understanding that underpins this requirement, as currently proposed the provision in 98.233 (j) (4) directs operators to apply the “adjustment multipliers” in the case “where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank”. It is completely unclear to how an operator would identify such a case and hence implement the “adjustment multipliers”.

Based on all of these readily apparent reasons, BP does not believe that the justification or adequate knowledge to apply the provisions of 98.233 (j) (4) exist and these should be removed from the rule.

To address the dilemma of having to sample and model each individual separator and tank combination and the resulting burden and cost, BP suggests two alternative approaches which will significantly reduce this burden while still yielding high quality data. In a particular subbasin entity within a hydrocarbon basin, the hydrocarbon liquid production from the same or very similar producing horizons/formations is very similar in composition, properties, and behavior and does not vary widely from one well to another. As EPA is aware, for a given producing well/site and fluid compositions, the separator pressure and differential pressure between the separator and the hydrocarbon liquid tank is the largest determinant of emissions from the tank, including CO2 and Methane. This characteristic allows a stratified sampling of separator/tank combinations within a Reporting Unit/Area to be used to develop a robust methodology of quantifying emissions from individual sites without sampling and modeling each separator/tank combination. Descriptions of each of these approaches follow:

Proposed Option 1: Sampling Without Modeling

Based on a significant number of hydrocarbon liquid sample flashing behavior using HYSYS, we have determined that greater than 95% of the CO2 in pressurized hydrocarbon liquids and greater than 98% of the methane in hydrocarbon liquids is released when the material is “dumped” to an atmospheric pressure storage tank. BP recommends that EPA not require modeling of tanks for emissions of methane and CO2, but simply assume that all methane and CO2 in pressurized condensate/crude is released to the atmosphere when the material is flashed to ambient pressure. This will eliminate the need for modeling of each tank as specified in the rule.

To address the case where tank emissions are routed to a combustion device (flare, incinerator, etc) for control, specify development of a multiplier, developed from a small number of tank modeling simulations in a sub-basin area, to be applied to the methane portion CO2 yield when combusted to estimate combustion of the total stream.

To address the burden posed by sampling (at pressure) and analyzing pressurized liquid from each individual separator in the industry, BP suggests that EPA enable a stratified sampling within a particular sub-basin entity as follows:

1. Determine the operating pressure range of the separators which dump hydrocarbon liquids to atmospheric tanks within the Reporting Unit/Area.

2. Select the lowest and highest pressure separators along with three additional sites with separator pressures which are approximately equally distributed between the lowest and highest pressure.
3. Obtain pressurized samples and analyses for each of the selected separators.
4. Directly calculate CO_2 and CH_4 emissions from the pressurized crude/condensate based on the total.
5. Plot the emissions versus separator pressure separately for Methane and Carbon Dioxide (if there are emissions) in Excel using the Scatter Plot option.
6. Click on the plotted points and select “Add Trendline” from the menu.
7. On the “Type” tab, select the trendline type which gives the reasonable best fit curve as defined by the highest R-squared value (avoid very high order polynomial curves). To show the R-squared value and resultant equation, On the “Options” tab, select “Display equation on chart” and “Display R-squared value on chart”, then select “OK”.
8. Use the produced equation to calculate the emissions for each separator/tank combination based on the site annual throughput and separator pressure. Company records, such as sales gas pressure measured at the site sales meter, shall be used to determine separator pressures.
9. Determine if vapor recovery units or combustion control devices are used for each tank in the population. If a combustion device is used determine the average destruction efficiency and apply it to the equation output and determine resultant emissions using the requirements of 98.233 (n). If a VRU is used, apply the estimated gas recovery percentage to the equation output to adjust the emissions determined by the equation.

Option 2: Regression Curve Storage Tank Approach for a Reporting Unit/Area

1. Determine the operating pressure range of the separators which dump hydrocarbon liquids to atmospheric tanks within the Reporting Unit/Area.
2. Select the lowest and highest pressure separators along with three additional sites with separator pressures which are approximately equally distributed between the lowest and highest pressure.
3. Obtain pressurized samples and analyses for each of the selected separators along with all data required by 98.233 (j) (1) (i) through (viii) if using E&P tanks as the modeling suite for emissions estimation. If using an alternative methodology (providing EPA enables options) collect all data necessary to use these alternative methodologies.
4. Run the modeling suite or laboratory GOR and determine emissions of methane and CO2 in pounds per sales oil (liquid) barrel.
5. Plot the emissions versus separator pressure separately for Methane and Carbon Dioxide (if there are emissions) in Excel using the Scatter Plot option.
6. Click on the plotted points and select “Add Trendline” from the menu.
7. On the “Type” tab, select the trendline type which gives the reasonable best fit curve as defined by the highest R-squared value (avoid very high order polynomial curves). To show the R-squared value and resultant equation, On the “Options” tab, select “Display equation on chart” and “Display R-squared value on chart”, then select “OK”.
8. Use the produced equation to calculate the emissions for each separator/tank combination based on the site annual throughput and separator pressure. Company records, such as sales gas pressure measured at the site sales meter, shall be used to determine separator pressures.

9. Determine if vapor recovery units or combustion control devices are used for each tank in the population. If a combustion device is used determine the average destruction efficiency and apply it to the equation output and determine resultant emissions using the requirements of 98.233 (n). If a VRU is used, apply the estimated gas recovery percentage to the equation output to adjust the emissions determined by the equation.

Exclusion or Simplified Estimation for Small Tanks

BP recommends that storage tanks at individual well sites or central tank batteries with a throughput of less than 5 barrels/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, BP recommends storage tanks at individual well sites or central tank batteries with a throughput below the 5 barrel/day threshold be allowed to use the appropriate emission factor from the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Gas Industry (API Compendium) in place of conducting sampling and analysis and/or modeling using process simulations.

Response: EPA agrees with the commenter on monitoring only hydrocarbon liquid tanks and has clarified text in today's final rule to indicate that only emissions from hydrocarbon liquid flashing is required to be monitored under the onshore production storage tanks source type. Flashing emissions from dissolved hydrocarbons in produced water is minimal and the burden associated with reporting from such a small source of emissions is not justified.

With regard to the use of alternate process simulators to estimate emissions from onshore production storage tanks, EPA has provided options on the use of software programs; see the response to EPA-HQ-OAR-2009-0923-1061-10.

EPA has reviewed the commenter's suggestion to eliminate the use of an "adjustment multiplier" and determined that the multiplier is a more cost-effective approach for informing future policy than requiring direct measurement. There is no simple way to simulate or calculate how much gas could bypass in a stuck-open dump valve or be entrained by vortex in the liquid drain from the separator to the storage tank. EPA's information from Natural Gas STAR partners and studies by the Houston Advanced Research Center and Texas Counsel on Environmental Quality indicate that sticking, leaking or vortexing through dump valves is not an uncommon cause of excessive gas emissions from field tanks. The fact that these emissions may go un-noticed or undetected for long periods in remote, un-manned operations suggests that basing tank emissions solely on separator liquid properties could significantly under-estimate those emissions. EPA's goal with inclusion of the adjustment multiplier is to inform policy in two regards: activity data on how common this cause of excessive emissions is occurring, and adjustment of liquid flashing emissions for this bulk gas bypass. EPA agrees that the conclusions in the TCEQ study are incomplete. However, the methodology and procedures used to measure the emissions from the storage tanks are acceptable making the data suitable for EPA's analysis. The HARC and TCEQ studies are the best-available, public data on crude oil stock tanks which revealed that approximately 50% of the tanks tested exhibited this phenomenon. Other data publicly reported in Natural Gas STAR workshops indicated that stuck-open scrubber dump valves were in one case the largest methane emission source in transmission compressor stations, and contributed nearly 90% of emissions in a transmission compressor station site survey (Natural Gas STAR Compressors Technology Transfer Webcast, January 18, 2006). Natural Gas STAR partners have responded to questions in workshops, stating that dump valve malfunction resulting in gas bypass is a problem that does occur.

In today's final rule, EPA does not require reporters to arbitrarily determine whether conditions in the tanks are actually at equilibrium conditions. Instead, in today's final rule, reporters are required to report occurrences of dump valves not closing during the calendar year. Because the gas that would bypass the separator level control valve is an important revenue stream for the operation, EPA concluded that production operators will be attentive to sales volumes of oil and gas, and recognize when separator dump valves are malfunctioning. Industry experts readily agree that this problem exists, more so in some fields.

EPA disagrees that the low correlation coefficient observed in the first method evaluated by the EPA to characterize emissions from tanks not at equilibrium conditions, renders the second method invalid. The adjustment multipliers in today's final rule are not related to the low correlation coefficients observed in the first method. In fact, the EPA justifies its usage of the second methodology over the first methodology based on these low correlation coefficients.

EPA has considered the methodologies suggested by the commenter and has decided to include the sampling without modeling option in today's final rule. EPA conducted a similar analysis using E&P Tank and observed that over 95% of the methane and carbon dioxide is emitted. As a result, EPA is allowing operators to determine the composition of the low-pressure separator oil using a standard method published by a consensus-based standards organization and assume that all of the CH_4 and CO_2 are emitted. This method requires no modeling and where such oil composition at separator pressure and temperature exists, this alternative significantly reduces the burden while maintaining the same data quality as the modeling methodology. While EPA agrees with the sampling without modeling option, EPA does not agree with the comment on aggregation of fields within a basin level reporting. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-46.

The EPA chose not to include the commenter's regression curve in today's final rule. For clarification on the issues regarding regression curves, please see the response to EPA-HQ-OAR-2009-0923-1305-52.

EPA agrees with the commenter's recommendation to include an equipment threshold for onshore production and processing storage tanks. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1151-121
Organization: American Petroleum Institute
Commenter: Karin Ritter

__Comment Excerpt Text:__
Section 98.233(j) Storage tanks.

API has several comments to clarify this category in the rule along with several proposals to broaden the methodologies available and to streamline the determination of GHG emissions from storage tanks thus significantly reducing the burden imposed by the proposed rule.

i. Source Category Scope
   To clarify the scope of this source category, EPA should modify Section 98.233 (j) to apply only to storage tanks receiving produced hydrocarbon liquids, rather than produced liquids as currently worded. All of the discussion in the preamble, the TSD, the calculation methodology in Section 98.233 (j), and the functionality of E&P Tanks apply only to hydrocarbon liquids. This clarification would make it clear that this source category does not encompass produced water tanks.

ii. Modeling Methodology
   API supports EPA's selection of modeling as the methodology for determining emissions from Storage Tanks and supports the use of E&P Tanks as an applicable model. However, as proposed, the rule restricts the selection of methods to modeling using E&P Tanks – latest software version. API believes the allowable methodologies should be broadened as follows:
   - Allow the use of E&P Tanks, Version 2 or higher as noted in Section 98.7.
   - Allow the use of process simulation models or industry accepted estimating methods as alternatives to using E&P Tanks. These models and methods are in wide use within the industry, are the "standard" for process design and optimization, and have much broader capabilities than E&P Tanks.
   - Allow the use of a "laboratory GOR" determination rather than modeling of separator tank combinations.

iii. Proposed Adjustment Multiplier

   API requests that EPA eliminate the "adjustment multiplier" provisions applied to the output of E&P Tanks as specified in Section 98.233 (j) (4). Based on the discussion of the derivation of these multipliers in the TSD, it appears that EPA is attempting to quantify abnormal equipment malfunctions of dump valves sticking and routing "raw" gas to the storage tank along with presumed "vortexing" of raw gas to the tank while dumping. The "adjustment multipliers" were apparently derived from examining a ratio of the output of runs from E&P Tanks, using the GEO-RVP method, to measured emissions from the recent TCEQ tank study report. API observes that the correlations of the same E&P Tank runs to the TCEQ data have very low correlation constants (0.0719 and 0.0045 for crude oil and condensate, respectively) in the TSD discussion of how they were derived. Although no evaluation of the accuracy of the "adjustment multipliers" is presented in the TSD, it would seem that they share the same low correlation between the two methods, and therefore have no basis. As EPA may be aware, to compound this issue, there is substantial doubt, even within TCEQ, that the TCEQ study was conducted correctly and the data is suspect. As EPA observed in the TSD, equipment malfunction and vortexing have not yet been thoroughly studied or quantified, the sample data set is limited (and of dubious accuracy), and only very weak correlations were observed for the available data. API also notes that the evaluation presented in the TSD was done using E&P Tanks in the GEO-RVP mode while the rule specifies running the simulation based on actual pressurized separator hydrocarbon liquid samples and conditions which further degrades any already dubious application of these "adjustment multipliers".

In addition to the very weak information and understanding that underpins this requirement, as currently proposed, the provision in Section 98.233 (j) (4) directs operators to apply the "adjustment multipliers" in the case "where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank". It is completely unclear to API and its members how an operator would identify such a case and hence implement the "adjustment multipliers".

Based on all of these readily apparent reasons, API does not believe that EPA has any justification or sufficient background data to apply the provisions of Section 98.233 (j) (4) and therefore these provisions should be removed from the rule. If EPA is interested in pursuing this type of event occurrence, API could participate in a limited cooperative study.

iv. Exclusion or Simplified Estimation for Small Tanks

For tanks, the same annual calculation method is prescribed regardless of the tank throughput, for example a tank that fills at a rate of 1 barrel/day versus a tank that fills at a rate of 100 barrels/day. API recommends that storage tanks at individual well sites or central tank batteries with a throughput of less than 5 barrels/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, API recommends storage tanks at individual well sites or central tank batteries with a throughput below the 5 barrel/day threshold be allowed to use the appropriate emission factor from the API Compendium in place of conducting modeling using process simulations.

v. API's Proposed Emission Estimation Alternatives

As proposed, the rule requires sampling and modeling of emissions from each individual separator transferring hydrocarbon liquids to a tank at atmospheric pressure. API estimates that this will require sampling of the pressurized separator hydrocarbon liquid at some 307,734 individual separator/tank combinations, followed by modeling of each individual tank. As currently configured, E&P tanks (or other process simulation models) cannot be used in a "batch processing" mode and each individual separator/tank combination would have to be individually set-up and modeled. API estimates the burden of the required sampling ($92.3 MM) and modeling ($15.4 MM) to be some $107.7 million for the covered portion of the industry.

To address the dilemma of having to sample and model each individual separator and tank combination with the attendant burden and cost, API suggests two alternative approaches which will significantly reduce this burden while still yielding high quality data. In a particular Sub-basin entity, the hydrocarbon liquid production from the same or similar producing horizons/formations is very similar in composition, properties, and behavior, and does not vary widely from one well to another. For a given producing well/site and fluid compositions, the separator pressure and differential pressure between the separator and the hydrocarbon liquid tank is the largest determinant of emissions from the tank, including CO_2 and CH_4. This characteristic allows a stratified sampling of separator/tank combinations within a Sub-basin entity to be used to develop a robust methodology for quantifying emissions from individual sites without sampling and modeling each separator/tank combination. Descriptions of each of these approaches follow.

Method #1 Alternative as Proposed by API: Sampling Without Modeling

Based on modeling the flashing behavior of a significant number of hydrocarbon liquid samples using a process simulation model, one API member has determined that greater than 95% of the CO2 in pressurized hydrocarbon liquids and greater than 98% of the methane in hydrocarbon liquids is released when the material is "dumped" to an atmospheric pressure storage tank. API recommends that EPA not require modeling of tanks for emissions of methane and CO2, but simply assume that all methane and CO2 in pressurized condensate/crude is released when the material is flashed to ambient pressure. This will eliminate the need for modeling each tank as specified in the rule.

To address the burden posed by sampling (at pressure) and analyzing pressurized liquid from each individual separator in the industry, API suggests that EPA enable a stratified sampling within a particular Sub-basin entity as follows:

1. Determine the operating pressure range of the separators which dump hydrocarbon liquids to atmospheric tanks within the Sub-basin entity.
2. Select the lowest and highest pressure separators along with three additional sites with separator pressures which are approximately equally distributed between the lowest and highest pressure.
3. Obtain pressurized samples and analyses for each of the selected separators.
4. Directly calculate CO_2 and CH_4 emissions from the pressurized crude/condensate based on the total.
5. Plot the emissions versus separator pressure separately for CH_4 and CO_2 (if there are emissions) to determine the R-squared value.
6. Use the produced equation to calculate the emissions for each separator/tank combination based on the annual throughput and separator pressure. Company records, such as sales gas pressure measured at the sales meter, shall be used to determine separator pressures.
7. Adjust the emissions as necessary to account for the use of combustion control devices or vapor recovery.

Method #2 Alternative as Proposed by API: Regression Curve Storage Tank Approach for a Sub-basin Entity

API's second proposed estimation method follows the same approach as Option 1, with the exception of Steps 3 and 4 as outlined below. With this approach, modeling or emission estimation methods are applied to the stratified sampling of separators across the Sub-basin entity to develop a correlation equation relating emissions to volume of sales oil.

3. Obtain pressurized samples and analyses for each of the selected separators along with all data required by Section 98.233 (j) (1) (i) through (viii) for using E&P

tanks as the emission estimation model. If using an alternative process simulation model or industry accepted estimation methodology, collect all data necessary to use these alternative methodologies.

4. Run the modeling suite or laboratory GOR and determine emissions of CH_4 and CO_2 in pounds per sales oil (liquid) barrel.

API has developed examples of these optional estimation methods and could provide this information to EPA separately.

Response: EPA has clarified the text under onshore production storage tanks that reporting is only required from tanks storing hydrocarbon liquids. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-48.

In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.
In today's final rule, EPA disagrees with the commenter's suggestion to eliminate the use of an "adjustment multiplier". For further clarification, please refer to the response to EPA-HQ-OAR-2009-0923-1305-48.

In today's final rule, EPA is allowing the sampling without modeling option suggested by API. For further clarification, please refer to the response to EPA-HQ-OAR-2009-0923-1305-48.
In today's final rule, EPA has not included the regression curve option to estimate emissions. For further details, please refer to the response to EPA-HQ-OAR-2009-0923-1305-52.
In today's final rule, EPA has included an equipment threshold for onshore production storage tanks. For further details, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-0582-11
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
WCI Modifications: WCI recommends the method in SECTION 98.233(j) for calculating emissions from onshore production and processing storage tanks is replaced by the following method:

WCI recommends that the results of a periodic laboratory determination of GOR (Gas Oil Ratio) from a pressurized liquid sample (2009 API Compendium, #2 on p. 5-41) be used to quantify methane emissions at storage tank batteries where daily production exceeds a threshold value (>10 bbl/day).

A pressurized liquid sample will be collected annually at a point downstream of all field separators and prior to the point where produced liquid is flashed to atmospheric pressure (that is, where it enters the storage tank). In the laboratory, the sample is allowed to reach atmospheric pressure, the volume of gas generated measured (i.e. GOR determined) and a sample of the evolved gas collected and analyzed for methane and carbon dioxide content. Additional testing is required when a well is connected to or disconnected from the battery, or changes in separator operational parameters are made. Emissions calculated in this manner assume that the methane generated in this measurement is ultimately released to the atmosphere (where there is no vapor recovery in-place). At storage tank batteries where production is below the threshold (<10 bbl/day) E&P TANKS would be used to determine flow and vapor composition.

The assumption implicit with this approach is that only flashing losses are important for methane emissions from storage tanks. While small amounts of methane and carbon dioxide will be emitted during subsequent storage and handling, all the methane emissions quantified by this method will be attributed to the initial depressurized storage tank. Storage tanks equipped with vapor recovery units (VRU) are exempt, and measurements are limited to land-based storage tanks containing condensate and crude oil.

Methane and CO_2 emissions at storage tank batteries where the oil production rate is 10 barrels per day or greater shall be calculated in the following manner:

$$E\ CH_4/CO_2 = GOR * PR * 1/MVC * MWg * MF\ CH_4/CO_2 * 0.001$$

Where:

$E\ CH_4/CO_2$	=	methane or carbon dioxide emissions (metric tonnes/year)
GOR	=	Gas Oil Ratio (scf/bbl)
PR	=	oil production rate (bbl/measurement period)
MVC	=	molar volume conversion
MWg	=	molecular weight of the gas (kg/kg-mole)
$MF\ CH_4/CO_2$	=	mass fraction of methane or carbon dioxide in gas (kg CH_4/kg gas)
0.001	=	conversion factor (metric tonnes/kg)

Methane and carbon dioxide emissions at storage tank batteries where the oil production rate is less than 10 barrels per day shall calculate methane emissions using the E&P TANKS Model.

Sampling Protocol:

Sample collection for GOR determination.

A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location.

Sampling protocol specific to the collection of separator liquid can be found in the following publications:

1. Appendix C Sampling Protocol section (pg 33) of the E&P TANK Version 2.0 User's Manual. API is considering revisions to this software as the current version is "out of date with current EPA TANKS software".
2. Wyoming Department of Environmental Quality Air Quality Division guidance document entitled Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting

Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas. http://deq.state.wy.us/aqd/Oil%20and%20Gas/GUIDANCE2001.pdf
3. Gas Processors Association (GSA) Standard 2174-93, available for purchase at: www.gasprocessors.com/product.asp?dept_id=2500&sku=S+2174-93

The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.

Sampling and laboratory based determination of GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions.

[Table] Sampling interval (n in Eq. 1)

Oil Production rate (barrels/day)	Sampling interval
11 - 100	annual
101-500	semi annual
>500	quarterly

An additional sample shall be collected and analyzed if:
1. the oil production rate at the storage tank battery changes more than 20% for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).
2. separator operating pressures change by more than 10%

Determination of volume of liquid produced

The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of +/-5%.

Response: EPA agrees with the commenter's suggested methodology and has included it as an option. Please see the response to EPA-HQ-OAR-2009-0923-1305-48 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1011-42
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Section 98.233(j) Onshore production & processing storage tanks

El Paso estimates that gathering the data necessary to comply with the requirements for onshore storage tanks is one of the most costly sources relative to the emissions contribution. EPA has not considered this important aspect of the Subpart W rules as proposed and should consider alternative approaches to these sources. The proposed rule requires the following parameters for onshore production storage tanks:

- Separator oil composition;
- Separator temperature;
- Separator pressure;
- Sales oil API gravity;
- Sales oil production rate;
- Sales oil reid vapor pressure;
- Ambient air temperature; and
- Ambient air pressure.

Current sampling practices are not detailed enough to support modeling input requirements. Industry standard practice only collects basic compositional information and production measurements for liquids, while E&P Tanks requires full speciation data from an extended laboratory analysis. This liquid analysis is expensive and often the sample is difficult to collect since it requires gathering a sample at the separator pressure. For some separators, the hardware is not in place to collect a pressurized sample. In addition, specific safety precautions must be employed to gather the liquid sample.

It is El Paso's interpretation that engineering estimates can be used for the required operational parameters, since the rule does not specify metering and monitoring for these parameters. El Paso requests confirmation of this interpretation. In addition, El Paso requests that tanks with a throughput of less than 5 barrels/day be excluded from reporting under Subpart W or be permitted to apply a default emission factor from the API Compendium in place of conducting modeling using process simulations.

Response: EPA has included additional methodologies to determine operational parameters that require sampling, namely low-pressure separator oil composition and Reid vapor pressure. For further details, please refer to the response in EMAIL-0002-5 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).
The commenter's interpretation of using engineering estimates to determine the operational parameters for onshore production storage tanks is correct. This has been clarified in today's final rule.

EPA agrees with the commenter's recommendation to include an equipment threshold for onshore production storage tanks. Please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1206-39
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
This section on onshore production and processing storage tanks requires use of the latest software package for E&P Tanks. Section 98.7, however, references Version 2. It should allow use of Version 2 or most recent version. In addition, the rule should allow use of commercially available process simulators such as HYSIS or other similar process simulators. These are industry accepted sophisticated process simulators used across the industry to design these units and estimate emissions for permitting purposes. See TSD at 50. The appropriate parameters used

to conduct process simulation may vary depending on site specific conditions and the list included in this section should accommodate the variation.

Response: In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EMAIL-0002-12 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
GPA recommends that HYSYS be identified as an acceptable method for calculating GHG emissions from tanks, in addition to E&P Tanks. The use of HYSYS for tank calculations is particularly important due to recognized difficulty in collecting acceptable separator liquid samples when using E&P Tanks. In some case, the success rate for collecting acceptable separator liquid samples can be as low as 10%. HYSYS provides the flexibility to use extend gas analysis to model tank emission.

Response: In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

EPA has included additional methodologies to determine operational parameters that require sampling, namely low-pressure separator oil composition and Reid vapor pressure. For further details, please refer to the response in EMAIL-0002-5 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1058-4
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
E&P Tank

We would like to see EPA include other approved flash simulation packages in their methodologies for estimating carbon dioxide equivalent (CO_2e) from this industry sector. Some of these packages include, but are not limited to ProSim, HYSIM, HYSYS, ProMax, KFlash, Vasquez-Beggs, Tanks 4.0. Utilization of one or multiple of these packages will provide accurate flashing, standing, working and breathing (F/S/W/B) losses.

Response: In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EMAIL-0012-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923)
Organization: Milan Steube
Commenter: Milan Steube

Comment Excerpt Text:
Subpart W as proposed requires the use of "E&P Tank Version 2.0 for Windows Software" to determine field tank emissions for exploration and production operations. I'm not familiar with this tool. Rather, EPA's TANKS 4.09d is commonly used for this purpose in the regulatory work I do here in Southern California. Will I need to purchase and learn to use a new tool for the purpose of reporting emissions under Subpart W?

Note to EPA: I am forwarding this question to you in case you want to add something regarding why TANKS 4.09 cannot be used. I checked the TSD but it doesn’t discuss TANKS. Thanks.
Response:

Once finalized, facilities subject to subpart W would be required to calculate and report GHG emissions for all affected sources located at their facility using those calculation methods specified in the finalized subpart W. No other calculation methods would be permitted.

Response: In regards to EPA TANKS model, please see response to EMAIL-0005-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923) for clarifications on the use of this model for the purposes of Subpart W. However, in today’s final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1167-31
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
For small combustion sources, the use of burner ratings and estimated operating hours rather than direct fuel and/or operating hour monitoring to estimate emissions. For example:
* Especially during winter months, production fields employ numerous small heaters and other combustion systems. Separators fire periodically to maintain temperatures necessary to separate oil, water, and gas in the production fluid. The separator burner controllers are typically on/off systems; thus when the burners fire they combust gas at the rated capacity. Operators understand the annual duration of the separator burners operation and can estimate the number of hours of combustion.

- For estimating flash gas emissions from production liquids storage tanks, process simulators (such as HYSIS [superscript registered trademark symbol]), correlation equations (such as the Vasquez-Beggs Equations), and other approaches have been accepted by state agencies for years as accurate estimations of flash gas emissions and are appropriate for these estimates. Process simulations can also provide estimates of CO2 dissolved in production liquids. For example it is not clear if E&P Tanks is appropriate for estimating emissions from produced water streams (as required for produced water storage tanks by Section 98.233(j); if E&P Tanks is not appropriate, then HYSIS [superscript registered trademark symbol] or an alternative process simulation software appropriate for water streams would be required;

Response: In today's final rule, EPA does not require reporting of emissions from any external combustion equipment with a rated heat input capacity equal to or lower than 5 mmbtu/hr from reporting; however, an equipment count by type has to be reported. Please see Section II.F of the preamble to today's final rule for more details. Also, EPA is allowing alternate methods to determine the composition of field gas used in combustion equipment. Please see Section II.E in the preamble to today's final rule for further details regarding changes to field gas composition requirements.

In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10. Also, today's final rule has been clarified to not include produced water storage tanks for onshore production. Please see response to EPA-HQ-OAR-2009-0923-1305-48.

Comment Number: EPA-HQ-OAR-2009-0923-1151-70
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
(Preamble p. 65) EPA seeks comment on whether there are additional or alternative software packages to E&P Tank and GlyCalc that should be required to be used to calculate emissions.

The rule should allow reporters to use E&P Tanks and GlyCalc or any commercial process simulator software to estimate emissions from tanks and glycol dehydration. The rule should also not specify the version number of the software packages, as these programs are updated periodically. In addition, in Section VII.I of this document, API outlines an alternative estimation method for tanks than does not require modeling, but would provide accurate emissions estimation while reducing burden.

Response: In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.
EPA is allowing the use of alternate process simulators to estimate emissions from dehydrator vents. For further details please see Section II.D of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1014-11
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

<u>Comment Excerpt Text:</u>

Onshore Production and Processing Storage Tanks

Subpart W also requires oil and gas operators to monitor emissions from onshore production and processing storage tanks using an engineering estimation based on the latest software package for E&P Tank. 40 C.F.R. § 98.233(j), 75 Fed. Reg. at 18640. IOGA-WV notes that the E&P Tank program is designed for four specific tank systems: (1) low pressure gas separator, (2) high pressure gas separator, (3) low pressure oil separator and (4) high pressure oil separator. If an operator has an operating system that docs not fall within these four scenarios, however, E&P Tank is not appropriate to use. IOGA-WV requests that the agency establish clear guidelines outlining how operators should proceed in scenarios that fall outside of the four systems identified above.

Response: EPA disagrees with the commenter that E&P Tank is designed for four specific tank systems. E&P tank is designed to model two specific systems: tanks with separator, and stable oil tanks (tanks without separator). The low-pressure gas, high-pressure oil, or low-pressure oil are streams flowing into or out of the separator. In cases where an alternate operating system is observed E&P Tank may have limited use. However, in today's final rule, EPA is not constraining the reporters to the use of E&P Tank. For further information on alternate process simulators to estimate emissions from onshore production and processing storage tanks; please see the response to EPA-HQ-OAR-2009-0923-1061-10 for further details.

Comment Number: EMAIL-0005-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
Subpart W in 40 CFR 98.233 refers to a software package for E & P Tank. Where can I find more information on E & P Tank? Is this the EPA "tanks" program?

Response: The E & P Tank Version 2.0 software is available for purchase from IHS Standards Store, Jane's Information Group, Inc., 110 North Royal Street, Suite 200, Alexandria, Virginia 22314 (http://www.ihs.com). The EPA Tanks program is a separate software that estimates volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions from fixed- and floating-roof storage tanks. EPA Tanks is not applicable to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1026-13
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
The proposed rule would require that emissions measurements be taken for all tanks, without regard to size, throughput, and/or storage of volatile liquids, i.e_ actual potential to emit GHGs. Scrubber dump valves on tanks can be operated either automatically or manually. When operated manually, an operator is on-site and can determine if the valve has stuck and will immediately

address the failure, so application of an emission factor to this scenario would greatly over-estimate the leak rate from this source. This requirement should be limited to only condensate dump tanks with automatic dump valves, not all storage tanks.

Response: In today's final rule, EPA has included an equipment threshold for onshore production storage tanks. For further details, please see the response to EPA-HQ-OAR-2009-0923-1061-10. Also, today's final rule has been clarified to not include produced water storage tanks for onshore production. Please see response to EPA-HQ-OAR-2009-0923-1305-48.
EPA considered this comment and determined that reporters are required to report both automatic and manual dump valves in today's final rule. EPA has provided procedures in today's final rule to adjust for the time the dump valve has been open in the reporting period. Hence if the dump valve is known to have not been open, then the calculation avoids any adjustment in tank emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1042-19
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
98.233(j) Onshore Production and Processing Storage Tanks

ConocoPhillips Comment:

a.) We interpret this paragraph to only apply to storage tanks receiving produced hydrocarbon (crude oil or condensate) liquids. Our conclusion is based on:

The functionality of E&P Tank only applies to hydrocarbon liquids. The E&P Tank software help page describes E&P TANK as a package the predicts hydrocarbon emissions from oil production tanks. The description in the API Publication catalog describes it this way: Publ 4697 Production Tank Emissions Model (E&P TANK, Version 2.0) E&P TANK, developed in conjunction with the Gas Research Institute, is a personal computer model designed to use site-specific information in a user-friendly format to predict emissions from petroleum production storage tanks. The model calculates flashing losses and simulates working and standing losses, using data provided by the user. Calculations distinguish between HAPs and VOCs, showing detailed speciated emission rates from methane to decanes.

In §98.233(j), the following parameters are used to characterize emissions:
(i) Separator oil composition.
(iv) Sales oil API gravity.
(v) Sales oil production rate.
(vi) Sales oil Reid vapor pressure

In §98.6, Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

EPA stated in the preamble in II. E. 2. (2) 4th paragraph on page 18621 that this proposed rulemaking does not include emissions from tanks containing primarily water with the exception of transmission station condensate tanks…

We request that EPA clearly state that §98.233(j) Onshore Production and Processing Storage Tanks does not apply to produced water tanks

b.) We request that EPA be clear in stating this category does not apply to flowback tanks used for oil well testing. In our Alaska operations, open-topped tanks are used to flowback three-phase flow (oil, water, gas) during oil well testing. E&P Tanks will not accurately estimate such emissions. Rather, the GOR method proposed for the Well Testing and Venting Category does a much better job.

c.) EPA should allow the operator to group tanks with similar operating conditions to establish an emission factor (emissions/throughput) using E&P tanks for the group based on a statistical sampling of tanks. The emission tank factor will be applied to the total number of tanks to estimate the total annual emissions for all the tanks in the group.

Response: EPA agrees that the onshore production storage tanks does not include produced water. With regards to clarifying the rule text under onshore production storage tanks, please refer to EPA-HQ-OAR-2009-0923-1305-48.

In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.
Any emissions resulting from well testing have to be reported under the well testing venting and flaring source type, which uses the GOR method.

In today's final rule EPA has provided an equipment threshold that considerably limits the number of separators sending hydrocarbon liquids to tanks requiring detailed monitoring methods (equipment below the threshold use a simplified emissions factor approach.) EPA disagrees with commenter regarding allowing companies to develop emissions factors groups tanks with similar operating conditions as EPA does not have sufficient data to provide standard methodologies for statistical sampling of tank emissions nor did the commenter provide suggested methodologies to estimate emissions factors. Hence today's final rule does not allow for any sampling of tank emissions.

Comment Number: EPA-HQ-OAR-2009-0923-0582-9
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
WCI Recommendations:

Onshore production and processing storage tanks (SECTION 98.233(j))

USEPA requires the use of a modeling approach (E&P Tank) to calculate emissions from storage tanks in the production and processing sectors. In cases where the model will not accurately estimate emissions – situations where additional emission sources are routed to the storage tank, or vortexing is known to occur - USEPA requires reporters to apply a “correction factor” to adjust emissions upward to account for these additional emissions. In the Technical Support Document USEPA acknowledges several significant problems with this approach. The document states that “predicting and evaluating non-flashing effects on emissions (such as dump valves or vortexing) has not yet been thoroughly studied or quantified. The methods above have significant weaknesses as:

1. the sample data set (used to develop correction factors) is limited, and
2. only weak correlations were observed for the available data (r^2 = 0.0719 for oil and 0.0045 for condensate).”

Thus, in its present form, this methodology would not produce cap-and-trade quality data.

Therefore, WCI recommends the use of a different methodology based on the measurement of GOR for produced liquids at a location immediately prior to the storage tank. The inherent assumption being that all gas contained in liquids entering a storage tank (at atmospheric pressure) will be released to the atmosphere, either in the storage tank or as the liquid is transported prior to refining. This method is presented below in the section titled WCI Modifications.

Response: Because the Mandatory Reporting Rule has the primary intent to inform future policy, EPA deems it inappropriate to fashion the MRR data reporting requirements with a specific policy goal, such as cap and trade. In today’s final rule, EPA has retained the factors used to correct for additional emission sources routed to the storage tank; please see the response to EPA-HQ-OAR-2009-0923-1305-48.
In today’s final rule, EPA is allowing the sampling without modeling option. For further clarification, please refer to the response to EPA-HQ-OAR-2009-0923-1305-48.

Comment Number: EPA-HQ-OAR-2009-0923-1298-38
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
Onshore production and processing storage tanks

Section 98.233(j): The proposed rule requires modeling emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities and onshore natural gas processing facilities. Since the preamble (page 18621) explicitly states the “proposed rulemaking does not include emissions from tanks containing primarily water”, IPAMS requests that EPA state in Section 98.233(j) that produced water tanks are excluded. Accordingly, the activity data required for data reporting in Section 98.236(c)(10)(iv) should delete reference to “water” for liquids sent to atmospheric tanks.

Response: EPA agrees that the onshore production storage tanks does not include produced water. With regards to clarifying the rule text under onshore production storage tanks, please refer to EPA-HQ-OAR-2009-0923-1305-48.
The EPA agrees with the commenter's request to delete the references to water in Section 98.236(c)(10)(iv) in the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002). In today's Final Rule, the text under the Section 98.236 for onshore production storage tanks has been changed to only include sales oil.

Comment Number: EPA-HQ-OAR-2009-0923-1080-19
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
AKA recommends that tank batteries (§ 98.233(j)) with a throughput of less than 5 barrels/day of hydrocarbon concentrate be excluded from reporting under Subpart W. If exclusion cannot be provided, AKA recommends tank batteries below the 5 barrel/day threshold be allowed to use the appropriate emission factor from the API Compendium of Greenhouse Gas Emission Methodologies for the Oil and Gas Industry ("API Compendium") in place of conducting modeling using process simulations.

Response: In today's final rule, EPA has included an equipment threshold for onshore production storage tanks of 10 barrels per day. For further details, please see the response to EPA-HQ-OAR-2009-0923-1061-10. However, the EPA is not using an emission factor from the API Compendium for storage tanks below 5 barrels/day. Further details on the development of the emission factor can be found in the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Equipment Threshold for Tanks".

Comment Number: EPA-HQ-OAR-2009-0923-1080-6
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Another non-cost effective example of this is related to tanks, for which the same annual calculation method is prescribed regardless of the tanks throughput, for example a tank that fills at a rate of 1 barrel/day versus a tank that fills at a rate of 100 barrels/day. The prescribed method requires analysis of the separator liquid and collection of numerous operating parameters. The liquid analysis is expensive and often the sample is difficult or impossible to collect, even with higher liquid production rates, and should not be required for tanks with minimal throughput. Across the industry, there are thousands of tanks associated with very low liquid production rates and, therefore, minimal GHG emissions.

Response: In today's final rule, EPA has included an equipment threshold for onshore production storage tanks of 10 barrels per day. For further details, please see the response to EPA-HQ-OAR-2009-0923-1061-10.

EPA has included additional methodologies to determine operational parameters that require sampling, namely low-pressure separator oil composition and Reid vapor pressure. For further details, please refer to the response in EMAIL-0002-5 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1170-8
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:

Per the onshore production and processing storage tanks provision in 98.233(j), in order to run E&P Tanks program, as mandated in this Subpart, to calculate estimated emissions venting from tanks, a liquid sample must be taken off the separator to determine the oil composition and the Reid vapor pressure, two of the minimum parameters required to characterize emissions. In the Permian Basin, Pioneer has approximately 1,800 tank batteries consisting of at least 2 hydrocarbon tanks/battery. According to a reputable laboratory in Texas, an oil composition analysis costs between $500 and $700, depending on the API gravity of the sample, and a Reid vapor pressure analysis costs $125. In addition, the laboratory imposes a $180 charge for a quality check analysis on each sample. For a laboratory to determine the oil composition and Reid vapor pressure at all tank batteries in Permian, assuming there is only one separator/battery, the· laboratory analysis alone would cost, on the low end, approximately $1.4 million. This does not include the time and labor to travel to each battery to collect the samples, or the cost to purchase or rent the proper equipment to take samples. Also, if the battery has additional separators, the costs would increase proportionately. Pioneer requests that one sample be taken in each basin, or each "reporting unit" (per the “reporting unit" recommendation in point 1).

Further, in order to obtain the CO_2 and CH_4 mole percent to determine the volumetric and mass emissions, the calculation methodologies for a majority of the onshore petroleum and natural gas production sources refer to 98.233 (u) and (v). Section (u)(2)(i) states "If you do not have a continuous gas composition analyzer, then quarterly samples must be taken." Pioneer does not have continuous gas composition analyzers at tank batteries; therefore, per this Subpart, quarterly samples would be required, however it is very unclear as to where these samples must be taken. Are quarterly samples to be taken somewhere in the basin or at each tank battery? Further, this could potentially be problematic because sampling points are limited.

Pioneer requests clarification of EPA's justification for quarterly sampling. The composition of the gas would not vary significantly from battery to battery so quarterly sampling would be redundant and Pioneer contends that annual sampling would be adequate. In addition, Pioneer requests that one annual sample be required per basin, or alternatively, in each reporting unit that is determined based on similar battery characteristics or throughput (per "reporting unit" recommendation in point 1).

Response: EPA has included additional methodologies to determine operational parameters that require sampling, namely low-pressure separator oil composition and Reid vapor pressure. For further details, please refer to the response in EMAIL-0002-5 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1201-8
Organization: North Slope Burough
Commenter: Edward S. Itta

Comment Excerpt Text:
Onshore production and processing storage tanks

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas and developed average emission factors based on direct measurement of vent gas flow rates[211]. The U.S. GHG Inventory mentions this study but indicates that "[b]ecause of the limited dataset and unexpected jumps in data points which can be attributed to non-flashing emission affects, the United States decided that further investigation would be necessary before updating the inventory emission factor"[212]. The study found "the direct measurement approach to be the most accurate for estimating oil and condensate storage tank emissions at wellhead and gathering sites; however, other, less accurate, approaches appear to be much more commonly used."

EPA proposes the use of modeling (E&P Tank) to calculate emissions from storage tanks in the proposed reporting rule. Yet the TSD acknowledges significant weaknesses with this approach.[213] Again, only a move towards more direct measurement (e.g., direct measurement of gas oil ratios, vent gas, and flow rates) will reduce these uncertainties in the reported data.

Response: EPA agrees with the commenter that the most accurate method of quantifying emissions is through direct measurement. However, EPA evaluated the cost burden of conducting direct measurement at all onshore production storage tanks and found that the cost increase is not justified by the increase in accuracy. As a result, EPA introduced several methodologies, besides direct measurement, that balance accuracy and cost. Hence today's final rule does not require direct measurement of emissions from tanks.
In today's final rule, EPA does not require quarterly sampling to determine the gas composition. Please see Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1151-37
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:

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[211] Hendler A., Nunn J., Lundeen J., McKaskle R., "VOC Emissions from Oil and Condensate Storage Tanks Final Report", April 2, 2009, available online at http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf.

[212] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3-47.

[213] See TSD at 134.

Section 98.233(j) Onshore production and processing storage tanks. The rule should allow the use of calculation methods that are currently acceptable under state-level permitting and reporting programs. Additional details on API's suggested alternative methods for onshore production and processing storage tanks are provided in Section VII.I of this document.

Response: In today's final rule, EPA has included some of the methodologies suggested by the commenter. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-48

Comment Number: EPA-HQ-OAR-2009-0923-1058-12
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

<u>Comment Excerpt Text:</u>
Paragraph (j) Onshore production and processing storage tanks outlines the software package for calculating F/S/W/B losses. As stated in the definitions section of these comments, we request the ability to utilize other software packages to calculate these emissions. This same comment is applicable to paragraph (2)(i) and (4) of this section.

Paragraph (j)(3) which currently states "Calculate emissions from liquids sent to atmospheric storage tanks vented to flares as follows:" should be modified to "Calculate emissions from liquids sent to atmospheric storage tanks where vapors are routed to flare(s) as follows:". In this Subpart the definition of "Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, or direct venting of gas used to power equipment (such as pneumatic devices)." " which is not accurate in describing the flow of gas from atmospheric storage tanks to a combustion device.

Response: In today's final rule, EPA is allowing the use of alternate process simulators to estimate emissions from onshore production storage tanks under certain conditions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1061-10.
EPA agrees with the commenter on the applicability of the word "vented" for vapors routed to flares. In today's final rule, "vented" has been replaced with "sent".

Comment Number: EPA-HQ-OAR-2009-0923-1151-84
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Paragraph Section 98.233(j), 2, i - The phrase "or to flare" should be added to the end of the sentence. Furthermore, a typographical error was noticed in the word, "Beneficial".

Response: EPA does not agree with the commenter. The downward correction for beneficial use does not apply to flares. When tank vapors are sent to a flare they result in GHG emissions from a flare and are not completely negated from the net balance of emissions. However, EPA has determined that stating thermal control devices in that section is incorrect and has made edits to today's final rule to reflect the correction.

Comment Number: EPA-HQ-OAR-2009-0923-1151-91
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Sections 98.232(c)(10) and Section 98.233(j): For each tank in hydrocarbon service, the rule requires inventory of the tank physical and operational parameters, sampling (@ separator pressure) and analysis of the inlet liquid stream, and modeling of emissions using E&P Tanks. Since the sampling occurs at the separator, the cost comparison is based on the number of separators, some 380,000 in natural gas and oil production operations from EPA's national inventory. Assuming that the rule covers 81% of these, some 308,000 separators require sampling under the rule. Assuming that the physical and operational inventory is embedded in the well-site inventory and therefore zero incremental cost, that the compositional sampling and analysis of the hydrocarbon stream from each separator upstream of a tank costs $475, and that modeling each tank takes 0.5 hours at $100/hr, this yields a total cost of $192.3 MM.

Response: EPA disagrees with the commenter's cost estimate. It was never EPA's intent to require sampling of the low pressure separator oil. In today's final rule, EPA has allowed for the use of default compositions available from the simulation software program or best available data. See response to comment EMAIL-0002-5 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for further details. Also, EPA has provided equipment thresholds that significantly reduce burden by only requiring the detailed monitoring methods for equipment above the threshold; equipment below the threshold use emissions factors. Please see the response to EPA-HQ-OAR-2009-0923-1061-10 for further details. These changes to today's final rule should significantly reduce burden to reporters. Please see responses to EPA-HQ-OAR-2009-0923-1151-91 for further details on burden to report from this source.

Comment Number: EPA-HQ-OAR-2009-0923-0957-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
98.233 (j)(2)(i) The rule states that you can reduce the tank emissions calculated using EP Tank if you have vapor recovery. Do you still need to run EP Tank even though you have vapor recovery on the tank 100% of the time?

Response: In today's final rule, reporters must quantify emissions from tanks with vapor recovery units regardless of whether the vapor recovery unit is operational throughout the calendar year. EPA has determined that VRU systems are rarely operational throughout the calendar year and need to often be taken offline for maintenance. None the less, collecting data on emission reductions will make it possible for EPA to understand how much of the total tank emissions nationally are being captured to inform effective policy. Hence EPA has retained the requirement on all emissions being estimated before making a reduction adjustment.

Comment Number: EPA-HQ-OAR-2009-0923-1061-15
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
The Hy-Bon Engineering report should not be the basis for any EPA decision. At proposed § 98.233(j)(4), relating to storage tank emissions calculations, a factor of 3.87 is prescribed for sales oil < 45 API gravity. It appears that EPA chose this 3.87 factor based on a 2009 draft report written for the Texas Commission on Environmental Quality (TCEQ) by a company called Hy-Bon Engineering.[214] That draft report was thoroughly flawed and, as far as we know, was never finalized and it was never used by TCEQ for any purpose. The many defects in the Hy-Bon Engineering report were detailed in comments submitted to TCEQ by TPA in 2009, a copy of which is attached to these comments. Accordingly, EPA should not base any decision in this rulemaking on the contents of the Hy-Bon Engineering report.

Response: EPA does not agree that the TCEQ study cannot be used to derive the factors. EPA studied TPA's critique of the TCEQ draft report by Hy-Bon Engineering, and while EPA has no comment on the overall points that TPA is making about the qualifications or motives of Hy-Bon Engineering, EPA did conclude that there is no basis for disputing the methodology or results of tank direct emissions measurements. EPA also concluded that this is no basis for disputing the flow rate of oil from the low pressure separator, the separator pressure during the measurement period or the oil type. Therefore, while EPA considers it appropriate to question the cause of excessive vapor emissions, EPA does not dispute the fact that in 50% of the tanks, the vapor measured out the tank roof far exceeded the modeled flashing emissions. To EPA's knowledge, neither TPA nor other peer reviewers of this report have offered any solid data or analysis demonstrating how such a finding (much more vapor venting from a tank than can be accounted for by an equilibrium flash calculation model) could be explained other than field gas from the gas-liquid separator somehow bypassing the liquid level control valve. This TCEQ study finding is corroborated by another independent study reported by HARC, which also found that many of the tanks studied had far higher vapor emissions from the tanks than could be accounted for by modeling the separator operating conditions and liquid properties for oil going into the tanks. For further information, see the response to EPA-HQ-OAR-2009-0923-1305-48.

Comment Number: EPA-HQ-OAR-2009-0923-1206-42
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:

[214] See EPA Technical Support Document at 51.

This provision attempts to account for tank emissions associated with an equipment malfunction event when a scrubber dump valve fails in the open position. There is an inherent weakness in the calculation method for this section because it is based on empirical data with a very poor correlation and very limited sample size. See TSD at 132. This section should be deleted, as should any calculations for GHGs occurring during malfunctions.

Response: EPA does not agree that the TCEQ study cannot be used to derive the factors. For further information, see the response to EPA-HQ-OAR-2009-0923-1305-48.

Comment Number: EPA-HQ-OAR-2009-0923-1074-34
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(j):

WBIH recommends the use of direct measurement on manifolded vent lines, existing and newly constructed, in response to this measurement option, as an optional monitoring method for emissions quantification for storage tanks at onshore petroleum and natural gas production facilities.

Response: EPA has provided several monitoring method options in today's final rule. Direct measurement by reporters was deemed onerous in terms of costs. Also, to keep the monitoring methods consistent, EPA has not included the use of direct measurement for tank emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1305-23
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(j) Onshore production and processing storage tanks

The rule indicates that this source applies to "emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned of operated by the reported.)"

The inclusion of stationary liquid storage tanks not owned or operated by the reporter is a complex and unreasonable requirement as reporters would be required to gather technical information, related to sales oil crude, from assets which they do not own or operate and this information may be confidential. In many cases multiple owner/operators may feed one crude oil storage tank; therefore, reporting agreements across multiple produces and field ownership will be very complex and difficult to resolve. The boundaries of this reporting requirement are also not clear, as BP feeds tanks not owned by BP and these tanks operate in series; therefore, BP is unclear if they would report the first tank or all sequential tanks as well. BP recommends the reporter only be required to report emissions from oil storage tanks owned/operated by the reporter.

Response: EPA disagrees that only emissions from onshore production storage tanks owned by the reporter should be reported. Today's final rule requires gathering data from separators, which are owned and operated by the reporter, to quantify emission from onshore production storage tanks. However, reporters will have to collect information on vapor recovery systems from owner and operators of onshore production storage tanks. For further details on legal authority to require reporting from leased, rented, and contracted equipment, please see the response to EPA-HQ-OAR-2009-0923-1031-21.

Comment Number: EPA-HQ-OAR-2009-0923-1151-36
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(j) Onshore production and processing storage tanks. The rule indicates that this source applies to "emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned of operated by the reported.)" Application of this section is assumed to apply only when the tank is owned or operated by the Sub-basin entity.

Response: EPA disagrees that the requirements to report emission from storage tanks not owned or operated by the reporter should be removed. Please refer to the EPA-HQ-OAR-2009-0923-1305-23.

Comment Number: EPA-HQ-OAR-2009-0923-1206-41
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
We also note that this provision refers to emissions from "atmospheric pressure storage tanks." Because storage tanks are either atmospheric or pressurized, but not both, the word "pressure" should be deleted here and in § 98.233(j)(1). Lastly, this provision would require emissions reporting of tanks not owned or operated by the reporter. This requirement should be deleted because it inappropriately creates obligations related to equipment over which owners and operators have no legal rights or other responsibilities.

Response: EPA disagrees with the deletion of the word "pressure" from the phrase "atmospheric pressure storage tanks". EPA disagrees that the phrase cited by the commenter suggests that atmospheric and pressurized tanks need to be reported. The phrase states that only storage tanks at atmospheric pressure must report emission under Calculating GHG Emissions – Onshore Production Storage Tanks in today's final rule.
EPA disagrees that the requirements to report emission from storage tanks not owned or operated by the reporter should be removed. Please refer to the EPA-HQ-OAR-2009-0923-1305-23.

13.2.2.2 TRANSMISSION STORAGE TANKS

Comment Number: EPA-HQ-OAR-2009-0923-1039-20
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Tank Emission Requirements for Gas Transmission Compression Facilities Should Be Limited to Condensate Tank Emissions and Clarifications are Required

§98.233(k) identifies emission reporting requirements for storage tanks located at natural gas transmission compression facilities. In the Proposed Rule preamble, EPA indicates that atmospheric tank working and breathing emissions associated with the condensate are insignificant. Rather, the concern is, "scrubber dump valves malfunction or stick-open due to debris in the condensate and can remain open resulting in natural gas bypass via the open dump valve to and through the condensate tank." [75 FR 18620] EPA provides no indication that other storage tank emissions for gas transmission are a significant emission source. However, §98.233(k) includes provisions for reporting from additional tanks.

INGAA recommends that §98.233(k) be limited to condensate tank emissions and deleting §98.233(k)(3), which references other tanks and calculation methods that apply for onshore production and processing. EPA should rename the source as "malfunctioning scrubber dump valve venting from condensate tank" to clarify the source of interest and avoid confusion with emission estimates commonly applied for atmospheric tank emissions.

If tanks and emission sources other than condensate tank emissions from malfunctioning scrubber dump valves are intended to be included, EPA should explain the significance of these emissions and why they should be considered for natural gas transmission sources, per the "80/20 rule" concerning insignificant emissions. In addition, calculation methodology should be clarified with options other than the optical camera allowed for detecting emissions from a malfunctioning scrubber dump valve.

A. Transmission Tank Emissions Reporting Should Be Limited to Condensate Tank Emissions

The Proposed Rule should be revised to appropriately refer to a malfunctioning scrubber inlet dump valve as the intended GHG emission source. Although the measurement point is located at condensate tank vents, defining "transmission storage tanks" as a source creates a broad undefined source category that extends monitoring, measurement and reporting provisions beyond the intended emission source.

The Proposed Rule preamble defines the five sources where EPA is requiring direct measurement, including natural gas transmission storage tanks. EPA has characterized these five sources as significant enough to warrant reporting, and the preamble states that no credible engineering method or emission factor exists to accurately quantify emissions. EPA further explains malfunctioning scrubber dump valves as the primary intended GHG emission source. These valves are located upstream of the transmission condensate tank and are the focus of the required leak screening and measurement requirements. The intent is clearly reflected in several quotes from 75 FR 18620 that are provided here:

"EPA is proposing to require five sources in this supplemental proposal to directly measure emissions: storage tanks (transmission) when scrubber dump valves are detected leaking (emphasis added)…"

The preamble further discusses rationale surrounding the inclusion of transmission storage tanks in direct emissions measurement. This discussion states that the actual transmission storage tank condensate volume is typically low and emissions are considered insignificant, emphasizing the intent to include the condensate tank only for the purpose of measuring emissions from malfunctioning scrubber dump valves.

"For example, storage tanks in the onshore natural gas transmission segment typically store the condensate (water, light hydrocarbons, seal oil) from the scrubbing of pipeline quality gas. The volume and composition of liquid is typically low and variable, respectively, in comparison to the volumes and composition of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are considered insignificant (emphasis added)."

The preamble also acknowledges that the measurement requirement is directed at identifying and measuring malfunctioning scrubber dump valves that have the potential to remain open, resulting in unintended gas bypass through the condensate tank.

"If the scrubber dump valve is stuck and leaking natural gas through the tank then the emissions will be visibly significant and will not subside to inconspicuous volumes. If the scrubber dump valve functions normally and shuts completely after the condensate has been dumped then the storage tank, emissions should subside and taper off to *insignificant quantities*."

Since the preamble clearly identifies the intent to include identification and measurement of malfunctioning scrubber dump valves, the Final Rule should limit transmission storage tanks to condensate tank vents to capture the scrubber dump valve as the GHG emission source and only refer to the associated tank vapor vent as the measurement point for determining excessive leakage. INGAA is receptive to monitoring the condensate tank vapor vent to identify leaking scrubber dump valves. To address this, INGAA recommends that §98.232(e)(3) be revised to read as follows:

"(3) Transmission condensate storage tanks venting due to scrubber dump valve malfunction." Subsequent rule reference to this source should apply the same nomenclature. Without this clarification, the undefined open-ended definition of transmission storage tanks could significantly broaden this source category to insignificant tank sources that were not characterized by EPA as emission points of concern and apparently not intended for reporting. Per EPA's discussion in the preamble, the volume and composition of liquid are typically low and variable from this segment and GHG emissions are expected to be insignificant.

Although INGAA strongly opposes inclusion of additional transmission compressor station storage tanks, if EPA decides to do so, the Final Rule should clearly identify and define the tanks of interest. EPA should document why inclusion of additional tanks is warranted. In addition, the Rule should allow flexibility in applying software tools and simulation programs to estimate such emissions (e.g., E&P Tanks, HYSIS, etc.). INGAA notes that E&P Tanks is the prescribed methodology for storage tanks at processing facilities.

B. Clarify Condensate Tank Vent Measurement and Emissions Calculation

A single annual "snapshot" optical screening and measurement (if continuous for more than 5 minutes) of condensate tank vent(s) does not consider the estimated time operating in a malfunctioning mode. While 98.233 (k) does outline the volume and concentration measurements, this section does not provide a calculation methodology for determining the annual emissions from a malfunctioning scrubber dump valve routed to a transmission condensate storage tank.

§98.233(k)(2) uses the undefined term "continuous" to determine whether the transmission condensate tank vapor vent should be measured with a meter. However, this terminology is not clearly defined and the emissions calculation method is not provided, including the time basis for estimating the duration of the malfunction event. These items should be clarified. For example, §98.233(k)(2) should indicate that "continuous" does not mean "measurable" over the 5-minute monitoring time, but rather "continuous and unabated" over the 5-minute monitoring time.

Similarly, §98.233(k)(2) should provide a calculation method and time basis for the calculation. INGAA recommends the following formula to calculate total annual emissions:

$Ea = V \times CH_4 \times T$
Where:
Ea = Annual methane emissions in cubic feet at ambient conditions from tank vapor venting resulting from a malfunctioning scrubber dump valves;
V = Measured tank vapor flow rate in cubic feet per hour;
CH_4 = Mole or volume fraction of methane in tank vapor; and
T = Approximate duration of malfunctioning scrubber dump valves in hours during the year (maintenance records or event logs can be used to "bound" the duration of the venting event).

C. Vent Emissions Detection Technology Should Not Be Limited to the Optical Gas Imaging Instrument

Alternatives to the optical camera should be allowed for identifying a malfunctioning scrubber dump valve and associated vent emissions.

EPA states in the preamble that "The only potential option for measuring emissions from scrubber dump valves is to monitor storage tank emissions with a gas imaging camera to determine if the emissions become negligible when dump valves close (emphasis added)." [75 FR 18620] Additional methods are available, as acknowledged by EPA in the Spring 2006 EPA Natural Gas STAR Partner Update Technology Spotlight:
"…methane leaks through dump valves can be discovered in several ways: (emphasis added)

•Go to the slop tank and listen for excess gas flowing to or through the tank (the easiest method).

•Look at the sight glass on the scrubber (if so equipped); if there is no liquid in the vessel, a leak should be suspected.

•Examine the throttling of gas through a leaking dump valve; a valve with frost indicates a leak.

• Listen for a leak through a dump valve.

• Use ultrasonic leak detection equipment with a touch probe to locate leaks through dump valves."

Similar to comments in the fugitive emissions section above, INGAA requests that EPA broaden the detection and measurement technology suite of tools to include all demonstrated technologies and alternatives that are used in practice. This should include alternative tools for vent gas measurement including calibrated bags and high-volume samplers (i.e., see Comment IV.C). Limiting the technology choice to optical infrared cameras is unnecessarily restrictive and precludes better and more efficient detection and measurement instruments.

Response: EPA agrees that it would be useful to reporters if EPA clarified that monitoring of transmission storage tanks applies to condensate tanks only, and today's final rule has clarified this.

EPA disagrees, however, that it should rename the source to "malfunctioning scrubber dump valve venting from condensate tank." EPA considered renaming the source per commenter requests, but determined that it is consistent with other sources in the rule to list the point of the emission, as opposed to the cause.

EPA disagrees that transmission storage tank venting emissions are insignificant and should not be included in the rule. Please see response to comment EPA-HQ-OAR-2009-0923-1009-6. Through EPA's Natural Gas STAR Program, EPA has learned that transmission storage tank venting from malfunctioning scrubber dump valves can be a significant source at transmission facilities. EPA used expert such that data will be gathered from this important source to inform future policy.

EPA disagrees that E&P Tank would be appropriate to monitor transmission storage tank vented emissions due to malfunctioning scrubber dump valves. E&P Tank relies of equations of state to model the volume and composition of gas that flashes out of a liquid solution due to a change in conditions, such as a pressure drop. It does not simulate emissions from a malfunctioning scrubber dump valve, which is the focus of this source.

EPA agrees that the transmission storage tanks monitoring method should allow for reporters to account for the fact that after repair the scrubber dump valve will stop leaking. It will improve the accuracy of the emissions estimates and better inform future policy. Today's final rule allows reporters to calculate emissions from the beginning of the reporting period to the time the leaking dump valve(s) is fixed.

EPA agrees that acoustic leak detection instruments utilizing the instrument manufacturer's quantification methods is an acceptable alternative to optical gas imaging cameras when screening for leaking scrubber dump valves. EPA sought to offer an alternative to optical gas imaging that has both an instrument manufacturer standard methods, and also will be available to all reporters; and thus, an option for acoustic leak detection of the dump valve has been added to the transmission storage tanks monitoring methods in today's final rule. However EPA disagrees with the other suggested methods. Please see response to comment EPA-HQ-OAR-2009-0923-1039-15. The two alternative methods that rely on the human ear to listen for the sound of a leak are unacceptable because this does not rely upon an instrument manufacturer's method and does not yield emissions quantification. In addition, visual observance of valves that are frosted does not rely upon an instrument manufacturer's method and does not yield emissions quantification. While reporters may still choose to look through the sight glass prior to or in addition to screening, not every scrubber will have a sight glass.

EPA disagrees with the comment to allow reporters to choose methods that are not specified in subpart W. Please see Section II.L of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). EPA's analysis of leak detection and measurement methods is outlined in the Technical Support Document EPA-HQ-OAR-2009-0923-0027, and in Section II.E of preamble to the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002).

EPA disagrees that calibrated bags or high volume samplers are appropriate alternatives to meters for gas leaking through a dump valve into a transmission storage tank. EPA's experience has demonstrated that the volumetric rate of emissions from this source may exceed the capacity of a high volume sampler and calibrated bags.

Comment Number: EPA-HQ-OAR-2009-0923-1024-30
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Transmission Storage Tank Emissions. The proposed text of Subpart W does not clarify whether the storage tanks to be monitored under the proposed 40 C.F.R. SECTION 98.233(k) are condensate tanks or other types of tanks, such as diesel, amine, glycol, or produced water tanks.[215] The preamble indicates that EPA intends for the methodology to apply to condensate tanks; Kinder Morgan supports that interpretation, and requests that EPA clarify the text of the rule accordingly.

More fundamentally, EPA's proposed methodology for quantifying emissions from transmission storage tanks is problematic in concept and raises significant safety implications. The premise of

[215] See Proposed Subpart W, 75 Fed. Reg. at 18,620.

the methodology appears to be that scrubber dump valve malfunctions, which are very rare events, can be reliably detected using optical imaging of the tank vent stack, and then quantified using a meter. However, EPA's method fails to distinguish emissions that are attributable to a valve malfunction from normal tank emissions caused by changes in temperature, pressure, and liquid level. These working and breathing emissions, while minor, would result in observation of continuous vapors using an optical gas imaging instrument. This, in turn, would require the installation of a meter to measure extremely minor emissions and not the scrubber dump valve malfunction indicated in the preamble. In addition, condensate storage tanks are frequently located high off the ground and cannot be readily equipped with fall protection devices such as railings or harnesses.

As an alternative to EPA's untested and potentially unsafe proposed methodology, Kinder Morgan strongly recommends that EPA adopt the use of E&P Tanks software to estimate transmission storage tank emissions. E&P Tanks is a widely used software tool within our industry and is the method currently accepted by EPA for calculating emissions from condensate storage tanks. The E&P Tanks program also can be expected to provide a more reliable emission estimate than direct measurement, because it accounts for seasonal and daily changes in temperature, pressure, and liquid levels that are not taken into account in the proposed Subpart W methodology.

If EPA does not accept the use of E&P Tanks™ for transmission storage tanks, Kinder Morgan believes tank vapors can be more accurately measured using calibrated bags or high volume samplers than using meters. Accordingly, if EPA is going to require the direct measurement of emissions at transmission storage tanks, Kinder Morgan requests that 98.233(k)(2)(i) be modified to reference 98.234(c) and (d), in addition to 98.234(b).

In addition, Kinder Morgan believes that the proposed rule is unclear with regards to the frequency of leak detection required for transmission storage tanks. Section 98.233(k)(1) refers to SECTION 98.234(a)(1) for how the optical gas imagining is to be conducted. According to SECTION 98.234(a): "You must use the method described as follow to conduct annual leak detection of fugitive emissions from all source types listed in SECTION 98.233(p)(3) (i) and (q)…" Kinder Morgan requests that SECTION 98.233(k)(1) be added to the source types listed in SECTION 98.234(a).

Response: EPA agrees that the rule should be clarified that monitoring of transmission storage tanks applies to condensate tanks only, and has made this clarification in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1039-20.

EPA disagrees that it will be difficult to determine the difference between working and breathing losses and a malfunctioning scrubber dump valve. EPA agrees that working and breathing losses are indeed small and intermittent, and thus should easily be distinguished as viewed through an optical gas imaging camera for five continuous minutes. A malfunctioning scrubber dump valve that does not close properly will vent large volumes of gas that will continually blow out of the tank, thus EPA has determined that the emissions targeted by this source are clear.

EPA agrees that safety should be a primary concern of reporters when monitoring transmission storage tanks; please see the response to EPA-HQ-OAR-2009-0923-1024-11. Of particular note, EPA allows the installation of permanent flow meters and the use of acoustic instruments so reporters can monitor these sources remotely and therefore never compromise safety.

Regarding the comments on E&P Tank, and calibrated bags and high volume sampler, please see response to comment EPA-HQ-OAR-2009-0923-1039-20.

EPA agrees that the proposed rule is not clear that reporters must monitor transmission storage tanks annually with an optical gas imaging instrument, and this has clarified this in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-0582-10
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Transmission storage tanks typically contain condensate liquids generated from the scrubbing of pipeline quality natural gas (small amounts of natural gas liquids). In the Technical Support Document, USEPA states the following "the volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant."

However, in an effort to quantify emissions which take place when a scrubber dump valve becomes stuck and gas flows directly from the separator to the storage tank, USEPA requires that reporters monitor storage tank vent emissions with a meter and measure storage tank gas composition to quantify emissions. Reporter must use an optical gas imaging instrument to monitor storage tank emissions for at least 5 minutes. If emissions are continuous (the assumption being that the scrubber dump valve is stuck open), then they must use a meter to measure emission flow rate from the tank. Reporters would use this flow rate and gas composition to quantify emissions. The calculation thus assumes that emissions have been at this level for the entire reporting period.

WCI has concluded that this methodology is subject to such large uncertainty that the resulting data would not be cap-and-trade quality. As USEPA states, this emissions source is insignificant, except in cases where a scrubber dump valve is stuck open.

This emission source might better be addressed by implementation of emission control regulations at the state jurisdiction level. Jurisdictions might require that reporters monitor the operational time of separator pumps to determine whether a separator/scrubber dump has malfunctioned, resulting in elevated emissions. If the scrubber pump run times are excessive, reporters would be then required to remedy the situation.

Thus, WCI recommends that reporters not be required to estimate emissions from transmission sector storage tanks.

Response: Because the Mandatory Reporting Rule has the primary intent of informing future policy, EPA deems it inappropriate to fashion the MRR data reporting requirements with a specific policy goal, such as cap and trade.

Today's final rule requires that transmission tanks found to be venting gas from malfunctioning scrubber dump valves are measured with a flow meter and the emissions be extrapolated for the period between the beginning of the reporting period and to the time if the valve was fixed. EPA is satisfied that this data will be sufficiently accurate to inform future policy.

EPA disagrees that this source should not be included in the rule. Please see response to comment EPA-HQ-OAR-2009-0923-1039-20.

Comment Number: EPA-HQ-OAR-2009-0923-1018-13
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
Pre-amble-page 65, "EPA seeks comment on whether there are additional or alternative software packages to E&P Tank and GlyCalc that should be required to be used to calculate emissions." ·

CAPP supports flexibility in the use of process simulation software in the estimating of emissions from storage tanks and glycol dehydrators. There is no practical reason why a reporter should not be allowed to use a process simulation package such as Hysys to estimate emissions should they choose to do so.

Response: With regard to storage tanks vented emissions, in today's final rule, EPA has provided for the use of alternative software programs. Please see the response to EPA-HQ-OAR-2009-0923-1061-10.

With regard to dehydrator vent, in today's final rule, EPA has provided for the use of alternative software programs. Please see the response to EPA-HQ-OAR-2009-0923-0053-4.

Comment Number: EPA-HQ-OAR-2009-0923-1206-43
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
This section on transmission storage tanks is another attempt to account for tank emissions associated with an equipment malfunction event when a scrubber dump valve fails in the open position. See TSD at 51. This is not a normal mode of operation and, as such, should be fixed as soon as possible when identified. Instead, the proposed rule would require an operator to allow the malfunction to continue until a crew can be mobilized to the site to complete direct

measurement of the emissions associated with the malfunction. This requirement is clearly not appropriate and should be deleted.

Response: EPA disagrees with the comment on scrubber dump valves, please see response to EPA-HQ-OAR-2009-0923-1061-10.

Comment Number: EPA-HQ-OAR-2009-0923-1305-24
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(k) Transmission storage tanks

Section 98.233(k)(1) refers to Section 98.234(a)(1) for how the optical gas imagining is to be conducted. Section 98.234(a) says "You must use the method described as follow to conduct annual leak detection of fugitive emissions from all source types listed in Section 98.233(p)(3)(i) and (q)…" Neither Section 98.233(k)(1) or Section 98.234(a) indicates the frequency for performing the optical gas imaging for transmission storage tanks. BP assumes the optical gas imaging is to be performed annually and not every time there is a release from the scrubber dump valve. EPA should clarify the frequency in the rule.

Response: EPA agrees that clarification of the monitoring frequency was necessary in today's final rule. Please see the response to comment EPA-HQ-OAR-2009-0923-1024-30.

13.2.3 DEHYDRATOR EMISSIONS ESTIMATES

Comment Number: EMAIL-0002-7 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
The next example is related to gas dehydration units, which are required by the proposed Subpart W to estimate annual emissions using the GLYCalc processes simulator. As with tanks, there are thousands of very small dehydration units operating across the natural gas industry with minimal GHG emissions. GPA recommends that dehydration units with a throughput of less than 10 million scf/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, GPA recommends dehydration units below the 10 million scf/day threshold be allowed to use the appropriate emission factor from the API Compendium in place of conducting modeling using process simulations.

Response: EPA agrees with the commenter on providing an equipment threshold, but EPA does not agree on the 10 million scf/day limit nor does EPA agree on the proposal to exclude all dehydrators below 10 million scf/day. . With regard to annual throughput threshold for dehydration units, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-0582-33
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:

Glycol circulation pumps (e.g. a Kimray pump) may be natural gas driven. Thus there will be gas emissions associated with the operation of these pumps which utilize natural gas. The spent Kimray pump gas is usually dumped into the rich glycol stream, and thus will be flashed off upstream of the reboiler if a flash tank is installed or in the absence of a flash tank, it will be flashed off in the regenerator and vented through the still column to the atmosphere. If this is the case, there is the potential for double-counting these pump emissions – as part of the flash tank or reboiler emissions and in the regulation section dealing with vented gas-powered pneumatic devices and pumps. One way to address this issue would be to require reporting of Kimray pump emissions using the pneumatic device methodology if the pump emissions are vented directly to the atmosphere. If the Kimray pump gas is routed to the rich glycol stream, reporters would not be required to meter Kimray pump gas consumption because these emissions would be captured by measurements made at the flash tank or reboiler vent.

If all (or a portion of) dehydrator emissions are controlled, that is pump gas, stripping gas and flash tank and still gas off-gas emissions are sent to a destruction device, they should not be reported here to avoid double counting.
Measurement Options: WCI evaluated the following options:

[Table]

Option	Pros	Cons
1) Emission Factors Use industry default emissions factors	Simplest and least labor intensive method	Large degree of error associated with default emission factors – data not rigorous enough for cap and trade
2) **USEPA** Engineering estimation using simulation software (GLYCalc™) and engineering calculation for desiccant dehydrators. USEPA method of choice.	May be less labor and resource intensive than direct measurement. Covers both glycol and desiccant dehydrators.	Method does require that reporters determine a suite of variables such as wet gas temperature, pressure, and composition. GLYCalc may underestimate emissions.
3) Direct measurement Measure volume (mass) and composition of all vented emissions (reboiler and flash tank)	Most accurate of the methods if sampling accurately reflects standard operating conditions. (Requires site specific sampling and analysis.)	Requires site specific sampling and analysis. Measurements must be made during "normal operation". Changes in dehydrator operational parameters may trigger additional sampling.

Response: EPA agrees with the commenter that as per the April 2010 proposed rule, EPA-HQ-OAR-2009-0923 there will be double counting of emissions if dehydrators use natural gas driven glycol circulation pumps. Hence, in today's final rule, EPA has provided a conditional reporting of glycol pumps from the natural gas driven pneumatic pump venting emissions source. If the reporter estimates emissions from glycol pumps under the dehydrator vent emissions source then the reporter needn't report the natural gas driven pneumatic pump venting source as stand-alone; if not, then the reporter has to estimate emissions from glycol pumps under the natural gas driven pneumatic pump venting emissions source.

Comment Number: EPA-HQ-OAR-2009-0923-0582-34
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
WCI Recommendations: WCI recommends the use of Option 2 as proposed in USEPA's reproposed subpart W. The model does not significantly underestimate glycol dehydrator emissions. It also avoids the problems associated with direct measurement and covers both glycol and desiccant dehydrators. The model calculates emissions from Kimray natural gas powered glycol circulation pumps. Thus Kimray pumps can be exempted from the metering requirements in the pneumatics methodology.

WCI Modifications: We recommend using the approach provided by USEPA without any modification.
USEPA Subpart W Approach:

USEPA's re-proposed subpart W requires emissions be reported from the following:

1) dehydrator vent stacks without vapor recovery or thermal control devices,

2) dehydrator vent stack emissions sent to a flare or used as fuel in the regenerator firebox/ fire tubes, and

3) vented emissions from desiccant dehydrators occurring during the refilling process

Quantification methods for these three emission sources are discussed below.

Uncontrolled dehydrator vent emissions

Reporters must calculate CH_4 and CO_2 emissions from uncontrolled dehydrator vent emissions using the simulation software pack GRI-GLYCalc Version 4.0. The regulation requires that, at minimum, the following inputs parameters must be supplied by the reporter and input to the simulation software.

i. Feed natural gas flow rate
ii. Feed natural gas water content
iii. Outlet natural gas water content
iv. Absorbent circulation pump type
v. Absorbent circulation rate
vi. Absorbent type: (TEG), (DEG), (EG)
vii. Use of stripping natural gas
viii. Use of flash tank separator (and disposition of recovered gas)
ix. Hours operated
x. Wet natural gas temperature, pressure, and composition

Controlled dehydrator vent stack emissions

Reporters must use methods found in section (n) Flare Stacks to calculate CH_4 and CO_2 emissions resulting from destruction of dehydrator vent stack emissions.

Emissions resulting from the venting and filling of desiccant dehydrators.

Periodically, desiccant dehydrators are depressurized and vented when desiccant is replaced. These venting emissions are to be calculated in the following manner:

Step 1 – Calculate natural gas volume released at standard conditions

E [subscript S, n] = (H * D^2 * P * P [subscript 2] * %G * 365d/ yr) / (4 * P [subscript 1] * T *

1,000cf /Mcf)

Where:
E [subscript S, n] = annual natural gas emissions at STP (Mcf)
H = height of dehydrator vessel (ft)
D = Inside diameter of the vessel (ft)
P [subscript 1] = Atmospheric pressure (psia)
P [subscript 2] = Pressure of the gas (psia)
P = pi (3.14)
%G = percent of packed vessel volume that is gas (void volume)
T = time between refilling (days)

Step 2 – Calculate CH_4 and CO_2 volumetric emissions using calculations in paragraph (u) of this section

Step 3 – Calculate CH_4 and CO_2 mass emission using calculation methods in paragraph (v) of this section

Response: In today's final rule, EPA has retained the methodologies for calculating GHG emissions from dehydrator vent, but has also provided an equipment threshold for dehydration units. For further details, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-1011-10
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
X. Proposed Rule Section 98.233(e) Dehydrator vent stacks.—El Paso requests confirmation that engineering estimates are acceptable as the operational parameters used to run the GlyCalc model. In addition, El Paso requests that dehydrator units with a throughput of less than ten (10) MMscf per day be exempted from the rule.

Response: EPA agrees with the commenter on using engineering estimation and providing an equipment threshold, but EPA does not agree on the 10 million scf/day limit nor does EPA agree on the proposal to exclude all dehydrators below 10 million scf/day. With regard to the use of engineering estimates for calculations and annual throughput threshold for dehydration units, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-1011-39
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
X. Section 98.233(e) Dehydrator vent stacks

Industry standard practices or current applicable regulations do not require continuous monitoring of pressure, temperature, flow rates and circulation rates for sources such as dehydrators and storage tanks. Typically, for a dehydrator, temperature and pressure at the reboiler are the only parameters monitored. The proposed rule requires the following parameters for characterizing emissions from dehydrators:
- Natural gas flow rate;
- Feed natural gas water content;
- Outlet natural gas water content;
- Absorbent circulation pump type(natural gas pneumatic/ air pneumatic/ electric);
- Absorbent circulation rate;
- Absorbent type;
- Use of stripping natural gas;
- Use of flash tank separator (and disposition of recovered gas);
- Hours operated; and
- Wet natural gas temperature, pressure, and composition.

It is El Paso's interpretation that engineering estimates can be used for the operational parameters used to run the GlyCalc model since the rule does not specify metering and monitoring for these parameters. El Paso requests confirmation of this interpretation. In addition, El Paso requests that dehydration units with a throughput of less than 10 million scf/day be excluded from reporting under Subpart W or be permitted to apply a default emission factor from the API Compendium in place of conducting modeling using process simulations.

Response: EPA agrees with the commenter on providing an equipment threshold, but EPA does not agree on the 10 million scf/day limit nor does EPA agree on the proposal to exclude all dehydrators below 10 million scf/day; EPA requires simpler methods for equipment below the limit as opposed to exclusion. After considering several comments on burden to report, EPA decided that an equipment threshold for dehydrators would reduce monitoring cost burden on the industry. Hence, in today's final rule EPA requires that only dehydrators equal to or greater than 0.4 million standard cubic feet per day throughput monitor their emissions using a software program; all dehydrators with throughputs below this value use an emissions factor. For further details on equipment threshold decision, please see Section II F of the preamble to today's final rule. For further details on equipment threshold determination analysis, please see rulemaking docket EPA-HQ-OAR-2009-0923 under "Equipment threshold for Dehydrators". In addition, it was never EPA's intent to require metering of throughputs from equipment. Hence EPA clarifies that engineering estimates of natural gas flow rate and hours of operation are sufficient for the calculations. Today's final rule also allows the assumption of saturated gas if feed natural gas water content is not available. Finally, today's final rule allows the use of default outlet natural gas water content and default wet natural gas composition when outlet natural gas content and wet natural gas composition are not available.

Comment Number: EPA-HQ-OAR-2009-0923-1014-12
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd
<u>Comment Excerpt Text:</u>

2. Dehydrator Vent Stacks

Subpart W requires oil and gas operators to calculate emissions from dehydrator vent stacks using an engineering estimation based on GlyCalc simulation software. 40 C.F.R. § 98.233(e), 75 Fed. Reg. at 18638. IOGA-WV requests that the agency confirm that, as long as all of the parameters specified in 40 C.F.R. 98.233(e)(l) are used, operators can utilize the full capability of the GlyCalc software for purposes of the required emissions calculations (i.e., operators may conduct the standard gas analysis rather than an extended analysis).

Response: EPA agrees with this comment. Hence, in today's final rule EPA allows the use of any simulation software that conforms to the requirements in Section 98.233(e) of today's final rule. For further details, please also see Section II.D of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1018-24
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (c)(2):
CAPP would like clarity on the following statement in sub-section (2): Who decides what is a "similar pump model"? Is this a role the EPA would take on and how would a facility go about receiving a decision on a similar pump model?

To avoid double counting of dehydrator glycol pump emissions, CAPP recommends that an exception to the rule for natural gas driven glycol circulation pumps (ie. Kimray) since these emissions would already be captured under dehydrator vent gas emissions (98.233e).

Due to the difficulty and burden of maintaining an accurate log of the liquid pumped for each pump on-site CAPP recommends as an alternative that facilities assume the pump is running at the rated design flow for a specified amount of time.

Response: With regard to "similar pump models", EPA requires the use of population emissions factors for pneumatic devices and hence the issue is not relevant in today's final rule. Please see Section II.F of the preamble to today's final rule for further details.

EPA agrees with the commenter with regards to double counting of emissions from glycol circulations pumps. Please see the response to EPA-HQ-OAR-2009-0923-0582-33 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1018-27
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman
Comment Excerpt Text:
98.233 (e)(3):
Based on feedback from industry members, CAPP does not believe the volume vented during dehydrator (or any other) vessel opening and refilling is significant enough to track. This activity

should only happen once per year and result in a small overall percentage of the basin level emissions. CAPP recommends that an alternative approach be taken by the EPA is it wishes to track these emissions.

Response: In today's final rule EPA has provided an equipment threshold on blowdown vent stacks. Any physical volume between isolation valves that is less than 50 standard cubic feet does not have to report in today's final rule; please see response to EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for further details. Hence, any dehydrator associated volume that is less than the equipment threshold does not have to report.

Comment Number: EPA-HQ-OAR-2009-0923-1055-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone
Comment Excerpt Text:
(98.233 (e)) The rule first exempts glycol units using thermal recovery from reporting dehydrator vent stack emissions. But in section (2) it requires that these emissions be reported. What do we do? Are the emissions exempt or should they be reported

Response: Please see the response to EPA-HQ-OAR-2009-0923-1305-34 for the treatment of glycol units in §98.233 (e).

Comment Number: EPA-HQ-OAR-2009-0923-1061-11
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
11. The rule should allow the use of new versions of software packages as they come on the market. Proposed § 98.233(e) prescribes the use of simulation software package GRI-GLYCalc Version 4.0. It may be that, after the rule is finalized, a new version of that package will be introduced onto the market. The new version should be available for use by those who are covered by the rule. Accordingly, the reference to Version 4.0 should be amended by adding "or later versions that become available". Such an amendment should be made at any point in the rule where the use of specific products or software packages is prescribed.

Proposed § 98.233(e) should also be amended to clarify how often an operator must characterize emissions as prescribed in subparagraph (e)(1). In addition, § 98.233(e) should contain a threshold level below which an operator could use the API Compendium instead of GLYCalc; TPA suggests that such a threshold be set at 10 million scf treated flow rate I day. Finally, subparagraph (e)(3) should be deleted because the emissions covered by (e)(3) will already be covered as a blowdown subject to the "blowdown vent stacks" provisions set forth at 75 Fed. Reg. 18640 (those provisions are currently mis-numbered as "iii" in the middle column of page 18640, as noted below).

Response: EPA agrees with the comment about software programs. With regard to flexibility of using software programs, please see the response to EPA-HQ-OAR-2009-0923-1014-12.

EPA agrees with the commenter on providing an equipment threshold, but does not agree on the suggested limit. For further details, please see the response to EPA-HQ-OAR-2009-0923-1011-39.
EPA clarifies that the reporter must characterize dehydrator emissions only once in a reporting period. Finally, EPA has clarified in today's final rule that desiccant dehydrators must report under the dehydrator vent source type. Please see Section 98.233(e) of today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1074-14
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment: WBIH supports the use of GlyCalc for dehydrator vent stacks emissions calculations

Response: In today's final rule, EPA has widened the calculation options by allowing the use of other simulation software. For further details, please see Section II.D of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1080-20
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>
AKA recommends that dehydration units with a throughput of less than 3 million scf/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, AKA recommends dehydration units below the 3 million scf/day threshold be allowed to use the appropriate emission factor from the API Compendium in place of conducting modeling using process simulations.

Response: EPA agrees with the commenter on providing an equipment threshold, but EPA does not agree on the 3 million scf/day limit nor does EPA agree on the proposal to exclude all dehydrators below 3 million scf/day. With regard to annual throughput threshold for dehydration units, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-1080-8
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>
Another example is related to gas dehydration units, which are required by the proposed Subpart

W to estimate annual emissions using the GRI GLYCalc processes simulator. As with tanks, there are thousands of very small dehydration units operating across the natural gas industry with minimal GHG emissions.

Response: EPA agrees with the commenter. With regard to GHG emissions from small dehydration units, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-1151-117
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
E. Section 98.233(e) Dehydrator vent stacks

For well-site dehydrators, Subpart W's requirement for engineering estimation is in direct contradiction with the Technical Support Document ("TSD"). By following Figure 1: Decision Process for Emissions Source Selection (TSD, p.22), the decision to use a population emissions factor and source count to estimate emissions is determined through the decision tree as follows:

1. Is source contributing to top 80% of emissions from each segment? YES
2. Is emissions source a fugitive? NO
3. Is vented emissions source geographically dispersed? YES
4. Does credible emission factor exist? YES
5. Use population emissions factor and source count to estimate emissions.

API recognizes that some field dehydrators are already subject to GLYCalc runs under current NESHAP Subpart HH. For these dehydrators, the incremental effort to calculate greenhouse gas emissions is manageable. For the other geographically dispersed field dehydrators which have less than 3 mmscfd actual annual average throughput and are not already required to perform a GLYCalc analysis, we propose the option of using the API Compendium emission factors (in Tables 5-1 and 5-2 for glycol dehydrator emissions) in lieu of direct measurement of parameters for the Engineering Estimation method. This option is consistent with the TSD decision tree outcome above.

As an alternative estimation option, API supports EPA's selection of modeling emissions from dehydration units and supports the use of GRI GLYCalc or other commercial software process simulators. API has several comments to clarify this category in the rule along with several proposals to broaden the methodologies available and to streamline the determination of GHG emissions from dehydration units thus significantly reducing the burden imposed by the proposed rule. In addition, EPA should recognize that CO2 emissions are presented in the regenerator overhead stream results from GLYCalc, not the emission stream.

As proposed, the rule restricts the selection of methods to modeling using GRI GLYCalc Version 4 and calculating controlled emissions separately. API believes the allowable methodologies should be broadened as follows:

a. Allow the use of GRI GLYCalc, Version 4 or higher.

b. Allow for calculating the flare or regenerator controlled emissions in GLYCalc.

c. Allow for the use of other commercial process simulators.

To address the dilemma of having to sample and model each individual dehydration unit and the resulting burden and cost, API suggests an alternative approach which will significantly reduce this burden while still yielding high quality data.

Dehydration Unit Calculation for a Sub-basin Entity

In a particular Sub-basin entity within a natural gas basin, the natural gas production from the same or similar producing horizons/formations is very similar in composition, properties, and behavior and does not vary widely from one well to another. In addition, for a given producing well/site and natural gas composition, the lean glycol flow rate is the largest determinant of emissions from the dehydration unit, including CO2 and Methane. These characteristics allow for simplifying the emission estimation from glycol dehydration without sampling and modeling each dehydration unit. The only information that will be required for each individual dehydration unit is the lean glycol flow rate determined by pump strokes per minute, if a gas assist pump or from pump setting information if using an electric pump. API has developed an example of how this could be structured and could discuss this approach further with EPA.

Response: Upon further analysis and review, EPA has determined that a population emission factor will provide acceptable emissions and activity data for smaller glycol dehydrators. Therefore, today's final rule provides a threshold of 0.4 mmscfd for application of a population emission factor derived using the 2009 API Compendium production factor. For further information on this threshold, see the response to comment EPA-HQ-OAR-2009-0923-1011-39.

For glycol dehydrators above this threshold, EPA disagrees with the commenter's application of the decision tree approach. The decision step 4 "Does credible emission factor exist?" was answered "No." The single emission factor presented in the API Compendium correlates emissions from all dehydrators simply with throughput. While this factor was derived using GlyCalc, EPA has determined that emissions correlate better with glycol circulation rate, contactor pressure and other attributes of the facility such as type of circulation pump, flash tank separator and stripping gas injection. Each larger unit will be different, so using GlyCalc will account for the lower emissions of operators who have installed emission reduction technologies, whereas the API Compendium factor will treat all larger glycol dehydrators the same, except throughput. Hence, EPA has retained the requirement for simulation of dehydrator emissions in today's final rule.

EPA agrees with the comment about software programs. With regard to flexibility of using software programs, please see the response to EPA-HQ-OAR-2009-0923-1014-12.

EPA disagrees with the use of GLYCalc calculations for flare or regenerator controlled emissions. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-52. EPA disagrees with the alternative approach for a dehydration unit calculation for a sub-basin entity suggested in this comment. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-52.

Comment Number: EPA-HQ-OAR-2009-0923-1155-24
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
22. Dehydrator Vents

We support EPA's proposed emission estimating method for dehydrator vents that relies on the GLYCalc model and engineering calculations for desiccant dehydrators.
Response: In today's final rule, EPA has retained the methodologies for calculating GHG emissions from dehydrator vent and has also provided an equipment threshold for dehydration units. EPA has also widened the calculation options by allowing the use of other simulation software. For further details, please see the responses to EPA-HQ-OAR-2009-0923-1011-39 and EPA-HQ-OAR-2009-0923-1014-12.

Comment Number: EPA-HQ-OAR-2009-0923-1206-36
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
This section for dehydrator vent stacks should allow the use of GRI-GLYCalc Version 4.0 or later. Also, it should establish a de minimus threshold below which the unit is excluded from reporting or is allowed to use API Compendium to estimate emissions. There are thousands of very small dehydration units operating across the natural gas industry with minimal GHG emissions. GPA recommends that dehydration units with a throughput of less than 3 million scf/day be excluded from reporting under Subpart W. If an exclusion cannot be provided, GPA recommends dehydration units below the 3 million scf/day threshold be allowed to use the appropriate emission factor from the API Compendium in place of conducting modeling using process simulations.

In addition, for units over 3 mmscf/d should allow use of commercially available process simulators such as HYSIS or other similar process simulators. These are industry accepted sophisticated process simulators used across the industry to design these units and estimate emissions for permitting purposes. See TSD at 43. The appropriate parameters used to conduct process simulation may vary depending on site specific conditions and the list included in this section should accommodate the variation.

Response: EPA agrees with the comment about software programs. With regard to flexibility of using software programs, please see the response to EPA-HQ-OAR-2009-0923-1014-12.

EPA agrees with the commenter on providing an equipment threshold, but does not agree on the suggested limit as well as exclusion. With regard to annual throughput threshold for dehydration units, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

Comment Number: EPA-HQ-OAR-2009-0923-1305-52
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
K. Section 98.233(e) Dehydrator vent stacks

BP supports EPA's selection of modeling as the methodology for determining emissions from dehydration units and supports the use of GRI GLYCalc as an applicable model. However, BP has several comments to clarify this category in the rule along with several proposals to broaden the methodologies available and to streamline the determination of GHG emissions from dehydration units thus significantly reducing the burden imposed by the proposed rule.

1. As proposed, the rule restricts the selection of methods to modeling using GRI GLYCalc Version 4 and calculating controlled emissions separately BP believes the allowable methodologies should be broadened as follows:

a. Allow the use of GRI GLYCalc, Version 4 or higher.

b. Allow for the calculating the flare or regenerator controlled emissions in GLYCalc.

2. To address the dilemma of having to sample and model each individual dehydration unit and the resulting burden and cost, BP suggests an alternative approach which will significantly reduce this burden while still yielding high quality data.

Dehydration Unit Calculation for a Reporting Unit/Area

In a particular producing area (Sub-basin entity) within a natural gas basin, the natural gas production from the same or very similar producing horizons/formations is very similar in composition, properties, and behavior and does not vary widely from one well to another. As EPA is aware, for a given producing well/site and natural gas compositions, the lean glycol flow rate is the largest determinant of emissions from the dehydration unit, including CO2 and Methane. This characteristic allows for only acquiring the average gas composition, pressure, and temperature within a Reporting Unit/Area and individual dehydration unit lean glycol circulation rate to be used to develop a robust methodology of quantifying emissions from individual dehydration units without sampling and modeling each dehydration unit. The only information that will be required for each individual dehydration unit is the lean glycol flow rate determined by pump strokes per minute if a gas assist pump or from pump setting information if using an electric pump. This would be structured as follows:

1. Split out dehydration units with flash tanks from those without flash tanks.

2. Based on at least 5 gas analyses, determine a weighted average composition (concentration on a volume%, dry basis) based on the production rate for the reporting unit/area.

3. Determine the average pressure (psig) and temperature (degree F) for the reporting unit/area. (For example, 365 psig and 75 degrees F based on field production data)

4. Determine the average water content of the dry gas (For example, 5 lbs H_2O/MMscf for sales gas requirements)

5. Determine the average water content of the lean glycol. (For example, 1.5 wt% H_2O from manufacture data)

6. Determine the maximum and minimum lean glycol flow rate (circulation rate) of each type of glycol pump used.

7. Determine if a gas injection or electric/pneumatic pump is used.

8. Determine if flash tanks are used and if they are the average temperature and pressure. If there are no flash tanks or flash tank vapors are vented to the atmosphere or used as stripping gas, use the no flash tank option. If there are some flash tanks that are controlled or recovered, do a separate set of runs at each of the lean glycol flow rate. Be sure to add the emissions from the flash tank control device to the regenerator vent emissions.

9. Determine if stripping gas is used and if they are the type of stripping gas and the flow rate of stripping gas (scfm) for each individual dehydration unit.

10. Determine if control devices are used. If a condenser is used determine the average temperature and pressure. If a combustion device is used determine the average ambient air temperature, excess oxygen, and destruction efficiency.

11. Using GRI-GLYCalc calculate the emissions from the dehydration unit at the maximum, minimum, and one or two levels in between of the lean glycol flow rate per pump type (based on manufacturer information) holding the following information constant:

- The average pressure and temperature for the reporting unit/area.

- The average composition (concentration by volume %, dry basis for the) for the reporting unit/area

- The average water content of the dry gas for the reporting unit/area

- The average water content of the lean glycol for the reporting unit/area.

12. Vary the lean glycol flow rate which with each run (0.33, 0.16, and 0.1 gpm)

- Use the electric/pneumatic pump option even if there is a gas injection pump if there is no flash tank or the flash tank emissions are uncontrolled. (Gas injection pump emissions will be added separately by dehydration unit). If there is a flash tank that tank that is controlled and a gas injection pump, use the gas injection pump option and enter in the calculated gas injection pump volume ratio for the pump using the following formula from the GRI GLYCalc Glycol Pump dialog box:

PVRa = PVRs * Ps * Ta / (Pa * Ts)

where:
PVRa, Actual Pump Volume Ratio (acfm/gpm)
PVRs, Standard Pump Volume Ratio (scfm/gpm) =
Pa, Operating Pressure (psig) =
Ta, Operating Temperature (oR) =
Ps, Standard Pressure (psia) =
Ts, Standard Temperature (oR)

- If there are no flash tanks or flash tank vapors are vented to the atmosphere or used as stripping gas, use the no flash tank option. If there are some flash tanks that are controlled or recovered, do a separate set of runs at each of the lean glycol flow rate. Be sure to add the emissions from the flash tank control device to the regenerator vent emissions.

- Run with no stripping gas even if stripping gas is used by the various dehydration units. (Stripping gas emissions will be added separately by dehydration unit.)

13. Save the file and run the calculations.

14. Print and save the Aggregate report. Note that the CO2 emissions are presented in the regenerator overhead stream results, not the emissions stream.

15. Rerun the calculations at each of the different lean glycol pump rates.

16. Plot the emissions versus the flow rate for methane and carbon dioxide in Excel using the “Scatter Plot” option. (Note the carbon dioxide emissions are not presented in the emissions summary but must be pulled from the regenerate vent results.)

17. Click on the plotted points and select “Add Trendline” from the menu.

18. On the “Type” tab, select “Linear”.

19. On the “Options” tab, select “Display equation on chart” and “Display R-squared value on chart”, then select “OK”,

20. Use the produced equation to calculate the emissions for each dehydration unit based on the lean glycol flow rate excluding emissions from gas injection pumps if no flash tank or

uncontrolled flash tank and stripping gas.

21. If a gas injection pump is used:

- Obtain from the manufacturer information the natural gas usage (scf/min) per glycol pump (gpm) based on the operating pressure (linear function).

- Multiply the natural gas usage (scf/min) at the average reporting unit/area pressure by the pump's lean glycol flow rate (gpm) to determine the natural gas emitted by the gas injection pump.

- Using the average natural gas composition for the reporting unit/area, determine the emissions of methane and carbon dioxide from the gas injection pump.
- Add the gas injection pump emissions to the rest of the dehydration unit emissions for both methane and carbon dioxide.

22. If dry gas or flash gas is used as a stripping gas:

- Obtain the gas flow rate (scfm) for each dehydration unit.

- Using the average dry gas or flash gas composition, determine the methane and carbon dioxide added by the stripping gas.

- Add the stripping gas emissions to the rest of the dehydration unit emissions for both methane and carbon dioxide.

Response: In response to the first section of this comment, with regard to flexibility of using software programs, please see the response to EPA-HQ-OAR-2009-0923-1014-12.

With regard to flare or regenerator controlled emissions, EPA has provided a method to calculate these emissions from dehydrators in today's final rule; please see Section 98.233(e) of today's final rule for further details. To keep the method consistent across the rule, EPA does not allow the use of GLYCalc calculations for flare or regenerator controlled emissions.

EPA reviewed the commenter's input and proposed alternative to the monitoring method provided by EPA in the proposed rule. However, EPA has determined that providing an equipment threshold, will significantly reduce the count of dehydrators that will need monitoring using a software program and achieve the same result, i.e. burden reduction, as using an alternative monitoring method suggested by the commenter . In addition, EPA has determined that if steps 16-19 in the commenter's proposed method are used to fit an equation to the sampled data, it is possible to generate fits that are not reasonable, i.e. with adjusted R-square values that are very low. In such cases the equation will not correctly represent the sampled values and cannot be used to characterize the entire dehydrator population. As such, EPA has not accepted the proposed alternative and instead provided relief in terms of an equipment threshold. For further information, please see the response to EPA-HQ-OAR-2009-0923-1011-39.

13.2.4 ACID GAS REMOVAL VENTS

Comment Number: EMAIL-0002-13 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
GPA further recommends that ProMax be identified as an acceptable method for calculating GHG emissions AGR units. In addition, GPA recommends that other mass balance calculations be allowed for AGR units. For example, an operator typically has metered volumes and composition analysis of gas entering an AGR unit and can conservatively assume 100% of the CO2 is removed (in some cases a few percent of the CO2 may not be removed). A simple calculation will provide accurate CO2 emissions from the AGR unit without the need for downstream metering or analysis. In other cases, operators may have meters and analysis on the AGR vent line and can provide a direct calculation of the CO2 emissions, again without the need for downstream metering or analysis. Subpart W should provide flexibility for any of these methods to estimate the GHG emissions from AGR vents.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-0582-31
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Measurement Options: Four options were evaluated for the calculation of ARU vented emissions. These options are shown below:

Option	Pros	Cons
1). Emission Factors Use default emissions factors (e.g., API, 2009).	Least resource and labor intensive method.	Very high uncertainty associated with available EFs. API lists two AGR vent CH_4 EFs, both have uncertainties >100%. EFs are available for CH_4 but not CO_2, thus this method is not applicable for CO_2- the major GHG released. Not cap-and-trade quality.
2). Simulation software Use of a model (e.g. API AMINECalc™, ASPEN™, TSWEET)	Data collection requirements may be less burdensome.	Models are designed for VOC calculations, not GHGs. Software may not work with AGR units which use a process other than the amine absorber technique. Accuracy and cap-and-trade quality are questionable.
3). Source Testing Direct measurement of reboiler vent emissions and volume of gas vent from the reboiler.	Accurate method if testing frequency accurately characterizes annual emissions.	Sampling of acid gases can be dangerous and expensive.
4). Mass balance calculation Measure carbon content and volume of sour and sweet gas streams.	Required data is currently available. USEPA method of choice. Data is cap-and-trade quality.	Method is only applicable for CO_2.

WCI Recommendation: WCI recommends use of the mass balance approach of USEPA (Option 4) with minor modifications. This method will provide cap-and-trade quality data, it is applicable to multiple sour gas treatment technologies, and does not require additional sampling as the required data is currently generated for process control purposes.

WCI Modifications: Language should be added to exempt reporting for this emission source in cases where acid gases are re-injected into the oil/gas field.

USEPA's methodology calculates annual CO2 emissions based on either continuous gas analyzer results or quarterly gas samples. Reporters must calculate and input the volume weighted annual average CO2 content for the gas entering and exiting the AGR unit. WCI recommends increasing the gas sampling frequency (determination of %Vol1 and %Vol2) to monthly where a continuous gas analyzer is not installed. The increased sampling frequency should not result in significant additional burden and should provide more accurate annual emission data.

Response: EPA disagrees with the modifications suggested by the commenter. In the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009), EPA was clear that subpart methods and calculation procedures must be followed whether or not there is subsequent injection underground or geologic sequestration. The GHG Reporting Program is not an emissions inventory; rather it is a reporting program that collects data to inform future climate change policies. The same rationale applies to subpart W in this final action. Data on CO_2 from an acid gas recovery unit is needed by EPA to inform future climate change policies, even if the CO_2 stream is subsequently injected underground. Therefore, such CO_2 streams must report for the AGR unit emission source.

In cases where CO_2 streams are injected underground for geologic sequestration, EPA provides methods for reporting that information in the proposed subpart RR, Geologic Sequestration. EOR operations may choose to opt-in to the proposed subpart RR.

This final rule will compile information on all emissions from sources in Subpart W, including capture or reuse of GHGs. In the context of this comment, not all of the CO_2 or acid gases separated in the AGR unit may be captured for sequestration or EOR operations, i.e. the efficiency of capture is not 100 percent. The difference between acid gases separated at the AGR and sequestration reported under Subparts RR and W will allow EPA to determine true emissions; an altogether exemption of AGR units that do a portion of the separation and capture will not account for these emissions. Hence EPA has retained the requirement for all acid gas recovery units to report.

In regards to the sampling, EPA determined that the incremental increase in accuracy from increased sampling does not justify the incremental burden from increased sampling. Since the intent of this final rule is to inform a range of policies and not provide data for compliance with a specific program such as cap-and-trade, EPA has retained the requirement for quarterly sampling.

Comment Number: EPA-HQ-OAR-2009-0923-1011-38
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Section 98.233(d) Acid gas removal (AGR) vent stacks

The proposed rule requires the following parameters for characterizing emissions from AGR:
- Metered natural gas inlet volume;
- Metered natural gas outlet volume;
- Volume weighted CO2 content of inlet gas;
- Volume weighted CO2 content of outlet gas.

Industry standard practices or current applicable regulations do not require continuous monitoring of natural gas flow and volume weighted CO2 content of the gas in and out of the AGR. Typically, for an AGR, natural gas inlet volume is the only parameter monitored. El Paso's recent cost estimate indicates it would cost more than $115K to install a metering facility to measure the inlet and outlet volumes for one amine unit. Given this high cost, an option to use estimated natural gas inlet and outlet volumes should be allowed.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1011-9
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233(d) Acid gas removal (AGR) vent stacks.—El Paso encourages the EPA to allow reporters to estimate the inlet and outlet volumes if not currently metered.

Response: EPA agrees with the comment and has allowed engineering estimation, under certain conditions, to calculate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1015-15
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
Acid gas emissions are calculated, not directly measured, using a mass-balance approach: Inlet gas is measured as is outlet gas – the difference is considered to be acid gas. This methodology has been an accepted method with regulatory agencies. Gas that is high in H2S, is highly corrosive: flow meters for acid gas have a high rate of failure and are highly unreliable due to the highly corrosive environment. PAW proposes an additional monitoring methodology using the "mass-balance" approach to calculating acid gas.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1024-26
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Acid Gas Removal Units. Individualized metering of the volume of gas flowing both into and out of every acid gas removal (AGR) unit is not necessary to determine emissions and should not be required.[216] Most AGR units at our facilities do not currently have meters directly upstream and downstream of the units. To install meters at every unit would entail substantial cost and cause considerable disruptions at our operations, since units would have to be shut down during meter installation. In lieu of direct metering, or as an additional quantification option, Kinder Morgan recommends that EPA allow appropriate computer modeling of AGR units, as the agency

[216] Proposed 40 C.F.R. SECTION 98.233(d).

proposes for emissions from onshore production and processing storage tanks[217] and dehydrator vent stacks.[218] There are several commercially available and widely used software packages, such as ProMax, that could be used to estimate emissions from AGR units with acceptable accuracy. Given the expense of direct metering and the logistical and safety issues it would cause, there appears to be no compelling reason why EPA should not permit the use of such emissions estimation software.

Alternatively, Kinder Morgan suggests that EPA clarify the proposed methodology to allow appropriate engineering estimation of volumes flowing through AGR units. In many cases, the volume of gas entering and exiting an AGR unit can be derived from data recorded at existing meters at other points in the facility. EPA should permit reporting entities to use such methods where appropriate, rather than require direct metering at every AGR unit.[219]

In addition, Kinder Morgan believes that Equation W-4 is difficult to apply to AGR units in EOR operations that capture flashed CO2, compress the CO2, and inject it into the ground. As written, Equation W-4 would classify this recycled CO2 gas as part of the unit's overall "emissions" even though the CO2 is never released to the atmosphere. Appendix A shows how Equation W-4 can be modified to reflect this use of CO2 at AGR units in service at EOR operations.

Response: EPA agrees with the commenter on the use of engineering estimation methods to determine flow rate when no meters (either flow rate or vent stack) or CEMS are already in placed. Typically, all of the gas processed in a facility is sent through an AGR unit to make the gas pipeline quality by removing acid gases. Since the gas into the facility is metered at various points, an engineering estimate can provide reasonable information on the gas throughput of the AGR unit. EPA also agrees with the commenter that either the inlet or outlet feed gas volume should be sufficient to reasonably estimate emissions. In today's final rule, EPA has provided flexibility in determining the flow rate to the AGR units, since the inlet and outlet flow rates differ by the amount of acid gas separated, and can be estimated using a mass balance approach. This method of estimating emissions will provide reasonable accuracy required for Subpart W. EPA also agrees with the flexibility to use simulation software where applicable. EPA allows for the use of any simulation software that meets the conditions specified in 98.233 (d) (4).

Today's final rule requires the use of CEMS data on emissions where CEMS are already in place. If CEMS are not already in place and not installed for purposes of this rule, data from meters on vent stacks can be used. If meters on vent stacks are also not available or not installed for the purposes of this rule then the reporter is required to use either any upstream or downstream meter already in place or simulation software. If none of the previous options are applicable, the reporter has the choice of adopting one of the previous options or using an engineering estimation of the flow rate and calculation method to estimate emissions. Hence,

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[217] Proposed 40 C.F.R. SECTION 98.233(j).

[218] Proposed 40 C.F.R. SECTION 98.233(e).

[219] If necessary, EPA can require that reporting entities keep documentation explaining and justifying the engineering calculations used to estimate volumes entering and exiting an AGR unit.

EPA has provide sufficient flexibility to use multiple options from the most accurate to the most reasonable of monitoring methods as applicable to different facilities.

EPA understands that AGR units in EOR operations may recycle all or a portion of their captured CO_2. If a an EOR operation chooses to opt-in to the proposed subpart RR and report geologic sequestration, EPA will account for the recycled CO2 as part of the proposed subpart RR's methodology for quantifying geologic sequestration. In addition, Subpart W final rule requires the reporting of any CO2 recovered at AGR units and transferred offsite. Between today's final rule and the proposed subpart RR, EPA will be able to develop a mass balance of all CO_2 in an EOR system. Exempting AGR units from EOR operations will result in negative emissions (or inflated sink) in the overall mass balance. Hence, EPA has retained the requirement for all AGR units, including those in EOR operations, in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1042-17
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§98.233(d) Acid Gas removal (AGR) vent stacks

ConocoPhillips Comment:

In certain cases, calculating CO2 vent emissions via mass balance using the acid gas removal unit inlet flow is more difficult and less accurate than by simply calculating the same emissions using the flow to the CO2 vent and the CO2 mol% from a vent stream gas chromatography (GC) analysis. The difficulty comes from the fact that elemental sulfur interferes with all methods of inlet flow measurement. As a result of this interference, there are no flow meters on the acid gas removal inlet. In order to calculate CO2 emissions, the acid gas removal unit inlet flow would have to be back calculated via mass balance using the sales gas flow from the acid gas removal unit outlet before it could be used to calculate CO2 emissions.

Since there are flow meters on each CO2 vent, and a vent stream sample is analyzed by GC, CO2 emissions could be calculated more efficiently and accurately by using the flow through the CO2 vent.

Therefore, the rule should include the option for facilities to calculate emissions using direct measurement where the flow and composition of the gas being vented are being monitored directly in the vent stack.

At certain other gas processing facilities equipped with cryogenic units to separate the ethane, propane and butane (EPB) streams from the inlet gas, CO2 also separates with the EPB stream. The CO2 rich EPB stream is then processed through an Amine Unit where CO2 is removed and vented to the atmosphere. For such a facility the rule should include an option to use a mass balance / engineering estimation approach to monitor / calculate CO2 vented to the atmosphere. Such an alternative methodology should be detailed in the monitoring plan.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

The commenter did not provide adequate details on the EFB scenario for EPA to provide any mass balance options. EPA reckons that if the EFB stream is eventually going through an AGR unit then one of the four options provided in today's final should be applicable.

Comment Number: EPA-HQ-OAR-2009-0923-1053-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
98.233 (d) The acid gas removal rule requires that you have a meter on the inlet and on the outlet of your amine unit. Will it be permissible to use the values from more than one meter? (For example, multiple wells with meters may flow into a compressor before flowing into the amine unit. The natural gas is metered at the well. Can these well meters be summed to determine the amount of gas flowing into the amine unit

Response: In today's final rule, EPA has provided multiple options to conduct engineering estimation of flow rates. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1054-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
98.233 (d) Usually, glycol units are located downstream of the amine unit and the sales meter is downstream of the glycol unit. Can the sales meter be used as the meter out of the AGR unit if the water vapor removed by the glycol unit is subtracted from the total.

Response: In today's final rule, EPA has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1058-11
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
§ 98.233 Calculating GHG emissions.
Paragraph (d)(1) under Acid gas removal (AGR) vent stacks outlines the methodologies acceptable to determine CO2e gas volumes. One method allows the use of pre and post AGR gas

unit samples to determine the CO_2e vented during operations. Current language states quarterly samples must be taken to determine CO_2e content. We request the sampling frequency be reduced to every other year or annually as gas composition in these processes does not fluctuate frequently enough to warrant quarterly sampling.

Response: EPA disagrees with the commenter. The commenter has not provided sufficient details or analysis in the comment to support the claim that gas composition does not fluctuate frequently. Furthermore, the acceptable levels of fluctuation are subjective and cannot be commented upon without quantitative information. Finally, AGR units often receive natural gas from several producing fields that feed varying volumes of natural gas throughout the year. This leads to a constant fluctuation in the mixture of natural gas from these various feed sources. Hence today's rule has retained the requirement for quarterly sampling of gas. However, EPA has provided relief in terms of sampling on inlet stream only and allowed the use of pipeline quality specification at the outlet stream. This will directly cut the sampling cost into half.

Comment Number: EPA-HQ-OAR-2009-0923-1060-22
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
Source Type:
Acid Gas Removal Vent Stacks

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(d)

Monitoring requirements/parameters:
1. Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition.
2. Volume weighted CO_2 content of natural gas into the AGR unit.
3. Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition.
4. Volume weighted CO_2 content of natural gas out of the AGR unit.

Comment:
Acid gas emissions are calculated, not directly measured, using a mass-balance approach: Inlet gas is measured as is outlet gas – the difference is considered to be acid gas. This methodology has been an accepted method with regulatory agencies. Yates' gas is high in H_2S, which is highly corrosive: flow meters for acid gas have a high rate of failure and are highly unreliable due to the highly corrosive environment. Therefore, Yates proposes an additional monitoring methodology using the "mass-balance" approach to calculating acid gas.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1061-13
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
The rule should allow engineering estimation methods for acid gas removal vent stack emissions. Proposed § 98.233(d) prescribes the use of a mass balance equation for calculation of emissions from acid gas removal vent stacks. In order to complete that equation, meters must be located both upstream and downstream of the amine treater. Few operators have such meters in place. Rather than prescribing use of mass balance equation, which would require unnecessary expenditures in order to install additional meters, EPA should allow engineering estimation (such as HySYS or Promax) to be used in place of mass balance equations

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. With regard to acceptable methods for calculating GHG emissions from AGR units, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

Comment Number: EPA-HQ-OAR-2009-0923-1151-116
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(d) Acid gas removal vent stack.

API supports EPA's selection of engineering methods to determine CO2 emissions from Acid Gas Removal Vents. However, API has several suggestions to improve this methodology, lower the burden imposed, and provide for rational implementation.

The requirements for Section 98.233(d) specifies "metered total annual volume of natural gas into the AGR unit" and "metered total annual volume of natural gas out of the AGR unit". The use of the term "metered" implies the flow must be determined using a flow meter. Paragraph 98.233(d) does not reference Section 98.234(b) (requirements for flow meters, composition analyzers and pressure gauges) and Table W-4 in the preamble specifies the monitoring method for acid gas removal vent stacks is engineering estimate. Since Section 98.233(d) does not refer to the flow meters requirements in Section 98.234(b) and the preamble does not indicate direct measurement is required for acid gas vent stacks, it appears EPA intended flow to be based on engineering estimate. Thus, API requests that the term "metered" be removed from Section 98.234(b) in regards to the volume of natural gas.

Requiring natural gas volume at both the inlet and outlet points is unnecessary, as the differential in flow between the two points is almost 100% attributable to the change in acid gas content of the gas entering and exiting the acid gas removal unit and CO2 emissions can be accurately determined with quantifying gas flow at either the inlet or outlet of the acid gas removal unit coupled, with sampling and analysis of the gas entering and exiting the unit.

In addition, CO_2 emissions can be accurately quantified by measuring the vent gas flow rate. Due to elemental sulfur interference, there may not be a flow meter on the inlet of the AGR unit. The inlet flow must be back calculated via mass balance using the sales gas flow from the outlet from each plant before it can be used to calculate CO_2 emissions. In some instances, a simpler and more accurate way to quantify the CO_2 emissions would be to use the flow to each CO_2 vent stream. The rule should include an alternative monitoring methodology for facilities where the flow and composition of the gas vented though the AGR vent stack is being monitored directly in the vent stack.
API requests that EPA remove the requirement for metering of gas at both the inlet and outlet from the acid gas removal unit and enable metering or engineering estimate at one point (the inlet, the outlet or the vent) to determine CO_2 emissions from AGR units.
In addition, API requests the following:

- Acid gas removal units are highly efficient at removing CO_2. As a result, it is not necessary to measure the CO_2 concentration of the outlet gas stream. It is a reasonable simplification to assume that all of the CO_2 in the inlet gas stream is removed.

- For acid gas removal units which do not have metering currently installed or where upgrades to the current metering would be required to meet the rule accuracy requirements and which would require a unit shut down to install or upgrade the required metering, API requests that EPA allow the use of Best Available Monitoring Methods (BAMM) information until the next scheduled shut-down of the unit where the metering could be installed or upgraded.
- For facilities with multiple acid gas removal units which are fed from a common pipe or header arrangement, API requests that EPA enable a common pipe approach where the volume (entering or exiting) and CO_2 concentration is determined at the common pipe/header rather than at each individual acid gas removal unit.

- The rule should include an alternative monitoring methodology for facilities where the flow and composition of the gas vented though the AGR vent stack is being monitored directly in the vent stack.

- The rule should provide a provision for acid gas removal units where the CO_2 removed from the inlet gas is captured and not vented to the atmosphere.- Acid gas removal vent stack emissions is defined in Section 98.6 as “acid gas separated from the acid gas absorbing medium…and released with methane and other light hydrocarbons to the atmosphere or a flare.” Since acid gas removal vent stack emissions include gases routed to a flare, Section 98.233(d) should be revised to clarify the calculation methodology in Section 98.233(d) applies when the emissions are released to the atmosphere and the calculation methodology in Section 98.233(n) applies when the emissions are routed to a flare.

Response: EPA agrees with the commenter on the use of engineering estimation of gas flow rates to the AGR unit, including flow rate estimation for AGR units using a common inlet header, under certain conditions; please see the response to EPA-HQ-OAR-2009-0923-1024-26. It must be noted, however, that the flow rate and hence emissions have to be estimated and reported for each AGR unit separately.

EPA agrees with the commenter on the measurement of flow rates at the inlet and outlet streams of an AGR unit. Today's final rule allows for the use of either the inlet or outlet stream flow rate in the calculation. EPA also agrees with and allows the option of using vent stack meters to estimate emissions from AGR units, including monitoring of a common vent stack connected to multiple AGR units. It must be noted, however, that the emissions have to be estimated and reported for each AGR unit separately.

EPA agrees with the commenter that AGR units are efficient in removing CO_2. However, not all of the CO_2 is removed from the natural gas; pipeline quality gas contains some amount of CO_2. Hence, EPA has provided the option of using pipeline quality specification at the outlet stream so as not to account for emissions that will not occur. Given the multiple options provided in today's final rule, EPA does not consider it necessary to provide BAMM for this source specifically. However, under certain conditions, the reporter may apply for a BAMM. Please see Section II.F. of the preamble to today's final rule for further details.

With regard to AGR units where all or a portion of the CO_2 removed from the inlet gas is captured and not vented to the atmosphere, please see the response to EPA-HQ-OAR-2009-0923-1024-26.

EPA disagrees with the commenter on reporting of AGR emissions being sent to a flare as flare emissions. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1305-25. However, in today's final rule EPA has made provisions to account for acid gas being sent to a flare to be reported as AGR unit emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1151-33
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(d)) Acid gas removal (AGR) vent stacks. Paragraph 98.233(d) defines the parameters V1 and V2 in Equation W-4 as "metered total annual volume of natural gas flow into AGR unit" and "metered total annual volume of natural gas flow out of the AGR unit", respectively. The use of the term "metered" implies the flow must be determined using a flow meter. Paragraph 98.233(d) does not reference Section 98.234(b) (requirements for flow meters, composition analyzers and pressure gauges) and Table W-4 in the preamble specifies the monitoring method for acid gas removal vent stacks is engineering estimate. API requests clarification that the volume of gas through the AGR unit can be based on engineering estimation. In addition, the requirement to measure the flow rate out of the AGR unit (as shown for Equation W-4) is not necessary as the difference in flow rates between the inlet and outlet are minimal. This is consistent with the required emission estimation method for AGR units in the California mandatory reporting regulation. Additional details on API's suggested alternative methods for acid gas removal are provided in Section VII.D of this document.

Response: Please see responses to EPA-HQ-OAR-2009-0923-1151-116 and EPA-HQ-OAR-2009-0923-1024-26 for a response to this comment.

Comment Number: EPA-HQ-OAR-2009-0923-1155-23
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

<u>Comment Excerpt Text:</u>
Acid Gas Removal Vents

We support EPA's proposed emission estimating method for acid gas removal vents that uses a mass balance calculation measuring carbon content and gas volumes. Both CO_2 and CH_4 emissions should be estimated and reported. Hydrocarbons (such as methane) contained in the incoming natural gas, may be absorbed in the amine stripping solution, and may be carried through the process and subsequently emitted to the atmosphere or sent to a flare and oxidized to CO2. We agree with WCI that gas sampling frequency should be increased to monthly, if continuous gas analyzers are not installed.

Response: EPA disagrees with the comment on increasing gas sampling frequency from quarterly sampling to monthly sampling. For further clarifications, please see the response to EPA-HQ-OAR-2009-0923-0582-31.

Comment Number: EPA-HQ-OAR-2009-0923-1206-28
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
GPA further recommends that ProMax and comparable programs be identified as acceptable methods for calculating GHG emissions from AGR units. In addition, GPA recommends that other mass balance calculations be allowed for AGR units. For example, an operator typically has metered volumes and composition analysis of gas entering an AGR unit and can conservatively assume 100% of the CO2 is removed (in some cases a few percent of the CO2 may not be removed). A simple calculation will provide accurate CO2 emissions from the AGR unit without the need for downstream metering or analysis. In other cases, operators may have meters and analysis on the AGR vent line and can provide a direct calculation of the CO2 emissions, again without the need for downstream metering or analysis. Subpart W should provide flexibility for any of these methods to estimate the GHG emissions from AGR vents.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units Please see the responses to EPA-HQ-OAR-2009-0923-1024-26 and EPA-HQ-OAR-2009-0923-1151-116 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1206-35
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
This section for acid gas removal vents requires gas metering and gas analysis into and out of the unit, which is not a routine practice in the industry today. The regulation instead should allow

conservative calculation assuming all CO2 is removed from the unit inlet, which only requires metering and gas analysis into the unit. In most cases this is a very close estimate and only a few percent of the CO2 is not removed. It also should allow use of commercially available process simulators such as ProMax or other similar process simulators. These are industry accepted sophisticated process simulators used across the industry to design these units and estimate emissions for permitting purposes. See TSD at 42.

Response: EPA agrees with the comment and has included additional options to estimate emissions from AGR units. Please see the responses to EPA-HQ-OAR-2009-0923-1024-26 and EPA-HQ-OAR-2009-0923-1151-116 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-19
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(d) Acid gas removal (AGR) vent stacks

Paragraph 98.233(d) defines the parameters V1 and V2 in Equation W-4 as "metered total annual volume of natural gas flow into AGR unit" and "metered total annual volume of natural gas flow out of the AGR unit", respectively. The requirement to measure the flow rate both in and out of the AGR unit (as shown for Equation W-4) is not necessary as the difference in flow rates between the inlet and outlet are minimal. This is consistent with the required emission estimation method for AGR units in the California mandatory reporting regulation.

Response: EPA agrees with the comment; please see the response to EPA-HQ-OAR-2009-0923-1024-26 for further details. .

Comment Number: EPA-HQ-OAR-2009-0923-1305-53
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(d) Acid gas removal vent stack.

BP supports EPA's selection of engineering methods to determine CO2 emissions from Acid Gas Removal Vents. However, BP has several suggestions to improve this methodology, lower the burden imposed, and provide for more streamlined implementation.

1. The current rule requires metering of gas flow into and out of each acid gas removal unit (mostly amine/solvent contactor vessels). Requiring metering at both points is unnecessary as the differential in flow between the two points is almost 100% attributable to the change in acid gas content of the gas entering and exiting the acid gas removal unit and CO2 emissions can be accurately determined with metering of gas flow at either the inlet or outlet of the acid gas removal unit coupled with sampling and analysis of the gas entering and exiting the unit. BP

requests that EPA remove the requirement for metering of gas at both the inlet and outlet from the acid gas removal unit and enable metering at either point. The methodology for determining emissions (98.233 (d)) would be modified as follows:

(d) Acid gas removal (AGR) vent stacks. For AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) using Equation W-4 of this section. For Volume measurement entering the AGR: Ea,CO_2 = (V*(Vol1% - Vol2%)) * 52.605 metric tonnes CO_2 per MMSCF (Eq. W-4a)

For Volume measurement exiting the AGR:

Ea,CO2 = ((V+(V*(Vol1% - Vol2%) * (Vol1%-Vol2%))*52.605 metric tonnes CO2 per MMSCF (Eq. W-4b)

Where:

- Ea,CO2 = Annual mass CO2 emissions in metric tons (volume is determined at STP conditions of 60 degrees f and one atmosphere pressure (14.7 psi), in MM standard cubic feet per year)

- V = Metered total annual volume of natural gas flow entering or exiting the AGR unit in standard cubic feet per year at 60 degrees F and one atmosphere condition.

- %Vol1 = Volume weighted CO2 content of natural gas into the AGR unit.

- %Vol2 = Volume weighted CO2 content of natural gas out of the AGR unit.

- 52.605 – metric tonnes of CO2 per million standard cubic feet (60 degrees f and one atmosphere pressure) of CO2

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, quarterly gas samples must be taken to determine %Vol1 and %Vol2 according to methods set forth in Section 98.234(b).

(2) Mass CO2 emissions shall be calculated from volumetric CO2 emissions using calculations in paragraphs (u) and (v) of this section.

Example:

Metered gas flow - inlet: 38,321.35 MMSCF
Metered gas flow – outlet: 36,500 MMSCF
Vol%1 CO2: 5.00% molar/volume
Vol%2 CO2: 0.10% molar/volume

Measurement at AGR inlet: (38,321.35 MMSCF*(5.00%-0.10%))*52.605 metric tons per MMSCF = 100,593 metric tons CO2

Measurement at AGR outlet:

((1000 MMSCF + (1000 MMSCF*(5.00%-0.01%)) * (5.00%- 0.01%)*52.605 metric tons per MMSCF = 100,593 metric tons CO2

*Note: Both metered gas flow rates are equivalent to a 100 MMSCF per day outlet flow rate for 365 days

a. For acid gas removal units which do not have metering currently installed or where upgrades to the current metering would be required to meet the rule accuracy requirements and which would require a unit shut down to install or upgrade the required metering, BP requests that EPA allow the use of Best Available Monitoring (BAM) information until the next scheduled shut-down of the unit where the metering could be installed or upgraded.

b. For facilities with multiple acid gas removal units which are fed from a common pipe or header arrangement BP requests that EPA enable a common pipe approach where the volume (entering or exiting) and CO2 volume % differential is metered and determined at the common pipe/header rather than at each individual acid gas removal unit.

- The rule should include an alternative monitoring methodology for facilities where the flow and composition of the gas vented though the AGR vent stack is being monitored directly in the vent stack.

- The rule should provide a provision for acid gas removal units where the CO2 removed from the inlet gas is captured and not vented to the atmosphere.

Response: EPA agrees with the commenter on the measurement of flow rates both at the inlet and outlet streams of an AGR unit. Today's final rule allows for the use of either the inlet or outlet stream flow rate in the calculation; please see response to EPA-HQ-OAR-2009-0923-1024-26.

In regards to capture of CO_2 at AGR units, please see response to EPA-HQ-OAR-2009-0923-1024-26.

In regards to the monitoring of vent stacks, use of common headers for feed into AGR, and BAMM please see response to EPA-HQ-OAR-2009-0923-1151-116.

13.2.5 FLARE CALCULATIONS

Comment Number: EPA-HQ-OAR-2009-0923-1018-28
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (f):

With respect to Equation W-6 CAPP recommends that this equation should be a summation of all individual events since the flow rate will change and facilities would have to sum all events to be able to accurately determine an "average" flow rate.

Under 98.233(f)(1)(i) CAPP wanted to bring it to the attention of the EPA that the measured flow rate of gas is likely to be non-linear with time as initially the production tubing contains significant water which is displaced over time. The amount of water the tubing contains will affect the volume of gas released in at a given time.

CAPP noted that equation W-7 incorrectly refers to casing diameter, when it should be referencing tubing diameter. Additionally, CAPP was unable to locate the source of Equation W-7 in 98.233(f)(1)(ii) and therefore we were unable to determine the basis for using a combination of "the volume of the production tubing down to the well depth" plus "sales rate times venting hours". In addition CAPP believes the use of sales rate in equation W-7 is not valid since it will fluctuate with changes in back-pressure. For this reason CAPP recommends the use of a simple choked-flow (tubing area) orifice equation like in Section (g)(ii) since down hole reservoir pressure is much greater than two times atmospheric pressure. (CAPP, 2002. Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities. Section 3.2.1).

If the EPA wishes to continue with the existing published equation W-7, CAPP recommends referencing the production tubing diameter and not the casing diameter.

Response: EPA disagrees with the commenter. Today’s final rule includes an equation where liquids unloading to the atmosphere is done with and without the aid of a plunger lift. When a well is unloaded to the atmosphere without a plunger lift, more than the tubing volume of the gas goes to the atmosphere as explained subsequently. In developing the emissions estimating options for well liquids unloading, EPA considered the options reported to the EPA Natural Gas STAR by companies who directly measured these emissions before and after installing plunger lift systems. EPA collaborated with Partners to develop the equation in the Natural Gas STAR Lessons Learned study “Installing Plunger Lift Systems in Gas Wells,” http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf, Appendix: Alternate technique for calculating avoided emissions when replacing blowdowns. The logic of this alternate technique, which reasonably matches Partner reported measurements, is that when liquid accumulation in the gas well tubing reaches a head which, combined with the sales line back pressure, suppresses gas production to near zero, it is equivalent to gradually shutting in the well. As this occurs, the reservoir pressure surrounding the well perforations rises to shut-in pressure, which accumulates in the well casing. If well gas production is stopped altogether by liquid accumulation in the tubing, it is the same as shutting in the well at the surface: the liquid will slump to the bottom of the tubing and the casing will be pressured up to shut-in pressure. This gas bubble blows the liquid accumulated in the tubing to the surface during a well unloading. It is correct that the gas in the tubing above the liquid, at sales line pressure, would be expelled first, but this is a small fraction of the gas bubble in the casing at shut-in pressure that pushes the liquid up the tubing to the surface. Natural Gas STAR Partners have reported that blowing liquids without the aid of a plunger lift is very inefficient as liquid coats the inner wall of the tubing and runs back down the well. Hence EPA assumed that all of the casing gas is required to clear significant portion of the liquids and provided for operators continuing to blow the well beyond the estimated time to blow off the casing gas pressure.

EPA has added the average sales rate times the venting hours to the equation. EPA understands from Natural Gas STAR experience that operators may sometimes leave a well open to the atmosphere longer than the time taken to blow-off the casing and tubing volumes, especially if it takes a long time for the well unloading to conclude. In such cases, EPA intends to capture the amount of gas lost between the well unloading completion and the time the well is opened back to the sales line. EPA recognizes that in the proposed rule there was some overlap of emissions in the equation provided. However, for today's final rule EPA has calculated how long it would take to blow off the bubble of gas in the casing up the tubing string in the average well: one hour (see Memo 6: Change to Rule Equation W-7:). Hence, EPA has adjusted the sales rate times venting hours by a factor for continued blowing a well to the atmosphere at average sales production rate for the period of time beyond one hour that the operator leaves the well open. EPA has also provided a calculation for blowing wells to the atmosphere with the aid of a plunger lift. This is necessary when the reservoir energy is no longer sufficient to lift both the plunger and liquid load against the sales line back pressure. For this calculation, EPA has determined that the volume of gas in the tubing at sales line pressure, with average sales flow rate beyond the estimated half-hour to expel the gas and liquid in the tubing is a conservative estimate. EPA recognizes that the well flow to sales fluctuates, and that this is an uncertain, highly variable way to estimate excess flow to the atmosphere after initial blow-off of the gas in the tubing and casing. However, considering the burden of installing a recording flow meter on every well that is blown to the atmosphere, EPA determined that this is a sufficient means of quantifying this excess venting to inform future policy.

EPA is not recommending a calculation across the well choke because this can be a complex calculation with sonic flow part of the time and subsonic flow for all or the remainder of the unloading time. The pressure upstream of the tubing string or choke is very uncertain with liquids being lifted inefficiently without a plunger lift and highly variable depending on the amount of liquid accumulation at the time a well is selected for liquid unloading. EPA has decided that the direct measurement of vent gas or the equations based on well depth, casing diameter, tubing diameter, shut-in and sales line pressures, and venting time will be cost-effective and adequately accurate in characterizing emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1018-32
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
98.233 (j):
Under 98.233(j)(1) CAPP believes that collecting separator temperature and pressure is not appropriate as the product will already be at atmospheric temperature and pressure due to transportation conditions.

With respect to 98.233(j)(2)(i) CAPP believes the words "or to flare" should be incorporated. Additionally there is a spelling error: "benefitial" should be "beneficial".

Could the EPA provide clarity to CAPP on the reference for the 3.87 and 5.37 factors used in 98.233(j)(4)(ii) and (iii)?

Response: EPA disagrees with the commenter on collecting separator temperature and pressure. The software programs that use Peng-Robinson equation require separator temperature pressure as an input to estimate flashing losses at the tank. The amount of vapors retained in the hydrocarbon liquids post separation phase is directly correlated with the temperature and pressure at the low pressure separator. Lower volumes of vapors are separated at low temperatures and high pressures. These vapors may then attain ambient conditions downstream, but they are nonetheless flashed through the tank. Hence using temperature and pressure from the low pressure separator is vital to an accurate representation of flash emissions.

EPA agrees with the commenter on the monitoring requirement to provide for tank emissions going to a flare and has made corrections to the typographical error. Please refer to Appendix E of the TSD for clarification and discussion for the 3.87 and 5.37 factors used in 98.233(j)(4)(ii) and (iii).

Comment Number: EPA-HQ-OAR-2009-0923-1018-33
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
In 98.233(l) (3)(ii)(1)(1) CAPP would like clarification on how the GOR is to be determined. Will it be based on a 1-hour test, a 24-hour test or some other time period or estimation method? CAPP notes that the requirement in Alberta is a 24 h test that is to be updated annually if GOR >100 m3/m3 and every three years if GOR < 100 m3/m3. In addition CAPP would like clarity from the EPA on whether there is a list of approved "consensus-based standards organizations".

Response: The intent of today’s rule is to gather relevant information with reasonable burden to industry. Hence, in today’s final rule, GOR can be determined by two methods; (1) using available data representative of the company’s facility, and (2) using standard consensus-based methods or standard industry practice. EPA has determined that using any consensus based standard will provide reasonable data quality to inform policy. Hence, in today’s final rule, EPA is not providing a list of approved standards, so as to not constrain the reporters, and allow them the flexibility of choosing the most appropriate standard. Some examples of approved consensus-based standards organizations are American Society for Testing and Materials, American National Standards Institute, American Petroleum Institute Standards, and American Gas Association.

Comment Number: EPA-HQ-OAR-2009-0923-1018-34
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
98.233 (m):

Again for 98.233(m)(1)(i), CAPP would like clarity from the EPA on whether there is a list of approved "consensus-based standards organizations".

CAPP would also appreciate comment from the EPA on whether or not it is necessary to determine the GOR for each well. In cases where the associated gas is flared, and the gas from the separator and treater is often metered before it is flared. This would give a direct measurement of the volume of gas flared.

Response: In today's final rule, EPA allows for use of GOR as determined for a cluster of wells within the same field to be used if individual well GOR is not available. With regards to a list of consensus-based standards organizations, please see the response to EPA-HQ-OAR-2009-0923-1018-33.

Comment Number: EPA-HQ-OAR-2009-0923-1018-36
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
CAPP would like to draw EPA's attention to equation W-14 in 98.233(n)(4), this equation is correct only if Yj includes carbon dioxide as well as the hydrocarbons listed.

Response: EPA disagrees with the commenter. The equation W-14 that estimated combustion emissions using Yj only accounts for hydrocarbons that are converted into CO_2, not the trace CO2 in product streams. Hence the equation has been retained. However, EPA did correct the other flare stacks equations (W-13 and W-15 in the supplementary proposed rule) to account for the un-combusted CO2 in the gas stream being sent to the flare. Please see the response to EPA-HQ-OAR-2009-0923-0582-29 and EPA-HQ-OAR-2009-0923-1074-36.

Comment Number: EPA-HQ-OAR-2009-0923-1042-20
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§98.233(l) Well Testing Venting and Flaring:

ConocoPhillips Comment:

a.) The proposed rule assumes that all emissions from well testing are either vented to the atmosphere or flared. In our Alaska operations, all gas generated from routine well testing is routed to the fuel gas system for use as fuel or for reinjection into the reservoir. Therefore, we request that the calculation methodology allow for beneficial use and be excluded from reporting emissions. See ConocoPhillips General comment for GHGs to report.

b.) This paragraph references the use of §98.233(u) for calculating GHG emissions. Paragraph (u) specifies quarterly sampling – something infeasible for the manner in which our Alaska facilities will be subject to this category; i.e., in the very infrequent and non-routine drill stem tests on exploration and other new wells where we use a portable flare and work to understand well characteristics in advance of production. Quarterly sampling for these would be costly and would produce no useful data. Thus, we request that EPA allow for a single, rather than a repeated quarterly, gas sample for each new reservoir.

Response: For the well testing venting and flaring source, the source monitoring method description clarifies that the emissions are to be reported only when there is venting or flaring. Hence, the commenter's concern with regards to modifying the calculation methodology to allow for beneficial use and being excluded from reporting is without any basis.

After considering several comments, EPA simplified the requirement for calculating GHG emissions by allowing for the use of existing composition data. Hence, this should mitigate any technical or cost constraints.

Comment Number: EPA-HQ-OAR-2009-0923-1060-20
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type:
Well testing venting and flaring

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(l)

Monitoring requirements/parameters:
1. Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
2. Flow rate in barrels of oil per day for the well being tested.
3. Number of days during the year, the well is tested.

Comment:
It is not industry standard to determine GOR by individual wellhead. Yates requests the use of BAMM for the first reporting year.

Response: In today's final rule, EPA allows for use of GOR as determined for a cluster of wells within the same field to be used if individual well GOR is not available. This allows flexibility for the reporter and manages burden. EPA still recognizes that the gathering of data from wells soon after the promulgation of this rule might pose a challenge to some reporters and therefore EPA is allowing the use of best available monitoring methods from this source from January 1, 2011 until June 30, 2011. For further details on best available monitoring methods for emissions from well venting and flaring, please see the Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-27
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
GPA recommends that HYSYS and other comparable process simulators be identified as acceptable methods for calculating GHG emissions from tanks, in addition to E&P Tanks. The use of HYSYS or comparable process simulators for tank calculations is particularly important due to recognized difficulty in collecting acceptable separator liquid samples when using E&P Tanks. In some case, the success rate for collecting acceptable separator liquid samples can be as low as 10%. HYSYS and similar programs provide the flexibility to use gas analysis to model tank emission.

Response: EPA agrees with this comment. Hence, in today's final rule EPA allows the use of any simulation software that conforms to the requirements in Section 98.233(j) of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-62
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
This requirement states that an operator must report the proportion of total natural gas to pure hydrocarbon stream being sent to a flare annually for the reporting period. This value is not required by the calculation methodology, so this requirement only creates an unnecessary recordkeeping and reporting burden on the operator. We request that EPA remove this requirement.

Response: EPA agrees with the comment that reporting the proportion of total natural gas to pure hydrocarbon stream being sent to flare annually creates unnecessary recordkeeping and reporting burden since the data is not readily available with the operator. Hence, EPA has removed this requirement from Section 98.236 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1305-50
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(l) Well testing venting and flaring

Section 98.233(l) requires determining the gas to oil ratio (GOR) of the hydrocarbon production for each well tested, determining the flow rate of oil for the well being tested, and tracking the number of days in the year that the well is tested.

The vast majority of well tests are conducted while the wells are in operation and do not require venting or flaring. As a result, the rule should exempt well testing that does not result in venting or flaring natural gas.

Response: The commenter's concern is without any basis. With regards to well testing that does not result in venting or flaring, please see the response to EPA-HQ-OAR-2009-0923-1042-20.

13.2.5.1 FLARE STACKS

Comment Number: EPA-HQ-OAR-2009-0923-0582-29
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
WCI Recommendations:

WCI recommends using the USEPA Subpart W methodology in SECTION 98.233(n).

WCI Modifications: WCI has identified a problem with the current USEPA methodology found in SECTION 98.233(n). We are currently seeking clarification from USEPA concerning this issue which is discussed below.

Calculation of Flare Stack Emissions (SECTION 98.233(n)(4))

We assume that the intent of the rule is to account for the following emissions from flare stacks:

1) uncombusted methane
2) carbon dioxide produced by combustion in the flare
3) carbon dioxide present in the inlet gas to the flare and passing through it

This section and Equations W-13, W-14, W-15 therein appear to be incorrect and confusing. For example:

- Calculation of CO2 emitted as pass-through from the inlet gas would presumably be accounted for by Equation W-13, but for CO2 the value of n (percent combusted) would be zero, not 98%.

- Equation W-15 includes the term E [subscript a, i] (combusted), but the equation as given is incorrect when i = CH_4. Since the TSD characterizes combustion methane emissions as negligible, we assume the intent is to ignore these negligible emissions and calculate only the uncombusted methane emitted from the flare stack.

We recommend a more explicit calculation of the emissions as follows:

(4) Calculate GHG volumetric emissions at actual conditions using Equations W-13, W-14, and W-15 of this section.

E [subscript a, CH_4] = V [subscript a] * (1 ?n) * X [subscript CH_4] (Eq. W-13)

E [subscript a, CO_2] (non ? combustion) = V [subscript a] * X [subscript CO_2] (Eq. W-14)

E [subscript a, CO_2] (combustion) = [sigma symbol with j below] (n * V [subscript a] * Y [subscript j] * R [subscript j] (Eq. W-15)

E [subscript a, CO_2] (total) = E [subscript a, CO2] (non ? combustion) + E [subscript a, CO_2] (combustion) (Eq. W-16)

Where:

E [subscript a, CH_4] = Contribution of annual uncombusted CH_4 emissions from flare stack in cubic feet, under ambient conditions.
E [subscript a, CO_2] (non-combustion) = Contribution of annual CO_2 emissions from CO_2 in inlet gas passing through flare stack.
E [subscript a, CO_2] (combustion) = Contribution of annual emissions from combustion from flare stack in cubic feet, under ambient conditions
E [subscript a, CO_2] (total) = Total annual CO_2 emissions from flare stack in cubic feet, under ambient conditions
V [subscript a] = Volume of natural gas sent to flare in cubic feet, during the year.
n = Percent of natural gas combusted by flare (default is 98 percent).
X [subscript i] = Concentration of GHG i in gas to the flare.
Y [subscript j] = Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).
R [subscript j] = Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

Response: EPA agrees with the comment and has sufficiently modified the equations related to flare stacks emission calculation to address all of the issues. The equations now capture un-combusted CH_4 emissions and total CO_2 emissions, where total CO_2 emissions include un-combusted and combusted CO_2 emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1015-12
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

<u>Comment Excerpt Text:</u>
When flares are used in emergency situations, concentration of GHG in the gas flared is not immediately available. PAW requests clarification that it is acceptable to calculate GHG emissions during upset conditions using available concentration data, and correcting the concentration as more accurate data becomes available following an upset condition.

Response: EPA agrees with the use of available concentration data and subsequent correction during emergency conditions. Please see response to EPA-HQ-OAR-2008-0508-0952-1, excerpt 54 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1060-26
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type:
Flares

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(n)

Monitoring requirements/parameters:
1. Volume of natural gas sent to flare in cubic feet, during the year.
2. Percent of natural gas combusted by flare (default is 98 percent).
3. Concentration of GHG i in gas to the flare.
4. Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).
5. Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

Comment:
When flares are used in emergency situations, concentration of GHG in the gas flared is not immediately available. Yates requests clarification that it is acceptable to calculate GHG emissions during upset conditions using available concentration data, and correcting the concentration as more accurate data becomes available following an upset condition.

Response: In today's final rule, the calculation method for flare stacks requires the use of "representative composition" of gas stream being sent to the flare. In regards to use of available concentration data, please see response EPA-HQ-OAR-2009-0923-1015-12 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1074-36
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(n):

WBIH requests clarification on the "un-combusted" emissions. Is this considered to be 2% when using 98% flare combustion efficiency?

Response: EPA has clarified the equations for estimating emissions from flare stacks in today's final rule. The un-combusted emissions are evaluated in two portions; un-combusted CO_2 and un-combusted CH_4 emissions. Un-combusted CO_2 emissions refers to the entire CO_2 volume present in gas being sent to flare. Un-combusted CH_4 emissions refers to the CH_4 present in the un-combusted portion of the flare gas; if flare efficiency is X then un-combusted CH_4 emissions refers to the volume of CH_4 present in (1-X) percent volume of the flare gas.

Comment Number: EPA-HQ-OAR-2009-0923-1151-39
Organization1**:** American Petroleum Institute
Commenter: Karin Ritter

__**Comment Excerpt Text:**__
25. Section 98.233(n)(2)(i) Flare stacks. The terminology utilized in this section is not representative of many gas plants, which do not utilize "de-methanizers". "De-methanizers" are typically utilized in natural gas liquid recovery or fractionation plants. A more appropriate name for use in place of "De-methanizer" would be "hydrocarbon dewpoint control plant". What gas composition is applied if a plant does not utilize a "De-methanizer"?

Response: In regards to calculations for gas processing facilities without de-methanizers, today's final rule has been updated to require dewpoint control point as the demarcation point. The dew point control is equivalent to a de-methanizer in terms of compartmentalizing the processing facility into two major streams of gas compositions, hence this change should provide sufficient clarity on what gas composition to use for estimating emissions. For composition of gas, please see Section 98.233(n) of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-40
Organization: American Petroleum Institute
Commenter: Karin Ritter

__**Comment Excerpt Text:**__
26. Section 98.233(n)(4) Flare stacks. Flare emission equations W-13, W-14, and W-15. As currently presented, Eq. W-13 assumes 2% of the CO2 present in the flared gas is uncombusted. CO2 already present in the gas stream is not impacted by flare efficiency; all of the CO2 present in the flared stream is emitted as CO_2. We suggest the following equations for CO_2 and CH_4 emissions from flares:

Eq. a: E [subscript CO2, a, i] = [sigma symbol with N on top and 1 on bottom] (V [subscript a] x X [subscript CO2] + n x V [subscript a] x [sigma symbol with i on top and 1 on bottom] (Y [subscript j, i] x R [subscript j]))
Eq. b: E [subscript CH_4, a, i] = [sigma symbol with N on top and 1 on bottom] (V [subscript a] x (1-n) x X [subscript CH_4])

Where:

E [subscript CO_2, a, i] = Annual CO2 volumetric emissions from flare stack at actual conditions for gas analysis i.
E [subscript CH_4, a, i] = Annual CH4 volumetric emissions from flare stack at actual conditions for gas analysis i.
V [subscript a] = Volume of natural gas sent to flare stack at actual conditions determined from Section 98.234(j)(1).
H = Percent of natural gas combusted by flare (default is 95 percent for non- steam aspirated flares and 98 percent for steam aspirated or air injected flares).
X [subscript CO_2] = Molar concentration of CO_2 in the flare gas determined from Section 98.234(j)(1).
X [subscript CH_4] = Molar concentration of CH_4 in the flare gas determined from Section 98.234(j)(1).
Y [subscript j, i] = Concentration of natural gas hydrocarbon constituents j (such as CH_4, ethane, propane, butane, and pentanes plus) for gas analysis i.
R [subscript j] = Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).
N = Number of required gas analyses during reporting year.

In addition, Equation W-15 adds scf of CH_4 emissions to scf of CO_2 emissions. The alternative equations provided above correct this problem.
Response: EPA has clarified flare stack emissions equations. For further details, please see the response to EPA-HQ-OAR-2009-0923-1074-36 and EPA-HQ-OAR-2009-0923-0582-29.

Comment Number: EPA-HQ-OAR-2009-0923-1151-41
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
27. Section 98.233(n)(8) Flare stacks. The phrase should read " Any emissions calculated under this source are excluded from other emission sources in Section 98.233".

Response: EPA disagrees with the comment. With regard to reporting requirements in Section 98.233(n)(8) of today's final rule, please see the response to EPA-HQ-OAR-2009-0923-1305-25.

Comment Number: EPA-HQ-OAR-2009-0923-1206-44
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
This section provides flexibility to use engineering calculations, company records, or similar estimates to determine volumetric flow to a flare. However, if a flare currently has a continuous flow meter, the proposal required it must be used to determine flow to the flare. The experience of GPA's membership is that existing flare meters may be accurate only at certain flow regimes and not for all flows from all sources to the flare. If existing meters are used to the exclusion of engineering estimates or other estimation methods, accuracy for flow determination to the flare

may be reduced. GPA recommends that an operator be allowed to use any combination of meters, engineering calculations, company records, or similar estimates to determine volumetric flow to a flare. The operator can then determine what combination of metering and calculation will provide the most accurate estimate of flow to a flare for the purposes of estimating GHG emissions.

Response: After considering these comments, EPA has revised language in today's final rule to provide for sufficient flexibility in using the continuous flow meters for ranges in which they are accurate and use of other options provided in the rule otherwise. Please see response to section 98.233(n) of today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1305-25
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
P. Section 98.233(n)(2)(i) Flare stacks

The terminology utilized in this section is not representative of many gas processing facilities, which do not utilize "de-methanizers". "De-methanizers" are typically utilized in natural gas liquid recovery or fractionation plants. What gas composition is applied if a plant does not utilize a "De-methanizer"?

Q. Section 98.233(n)(8) Flare stacks.

The phrase should read "Any emissions calculated under this source are excluded from other emission sources in 98.233".

Response: Regarding comments related to the "de-methanizer", please see response to EPA-HQ-OAR-2009-0923-1151-39 for further details.

EPA agrees and has revised today's final rule in 98.233(n) to correct flare emissions to avoid double counting.

13.2.5.2 ASSOCIATED GAS VENTING AND FLARING

Comment Number: EPA-HQ-OAR-2009-0923-0582-27
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
WCI Recommendations:

WCI recommends adoption of the calculation methodology set-forth by US EPA in section

SECTION 98.233(l) for vented and flared emissions resulting from well testing with minor modifications.

WCI Modifications:

WCI recommends deleting the following language. Deletion of this text will insure that GOR is determined by actual measurement and insure more accurate and consistent data.

SECTION 98.233(l)(1)(i) If GOR is not available then use an appropriate standard method published by a consensus-based standards organization to determine GOR.

Response: EPA considered the commenter's input however EPA has retained the requirements for GOR determination from the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002). EPA's intent is to gather relevant information with reasonable burden to industry. In the case of well GOR, oil and gas reporters will typically know their GOR, since it is normal practice to estimate GOR regularly. Hence use of this existing GOR value is deemed sufficient to estimate emissions from this source type.

Comment Number: EPA-HQ-OAR-2009-0923-0582-28
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
WCI Recommendations:

WCI recommends adoption of the method (SECTION 98.233(m)) published by US EPA in the most recent Subpart W with minor modifications.

WCI Modifications:

WCI recommends deleting the following language. Deletion of this text will insure that GOR is determined by actual measurement and insure more accurate and consistent data.

SECTION 98.233(l)(1)(i) If GOR is not available then use an appropriate standard method published by a consensus-based standards organization to determine GOR.

Response: EPA disagrees with the comment. With regard to modifications in Section 98.233(l) of today's final rule, please see the response to EPA-HQ-OAR-2009-0923-0582-27.

Comment Number: EPA-HQ-OAR-2009-0923-1151-123
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>

K. Section 98.233(m) Associated gas venting and flaring

Onshore Production Source Category: Associated gas venting and flaring

Section 98.233(m) requires determining the GOR of the hydrocarbon production from each well whose associated gas is vented or flared.

GOR determination for estimating emissions from venting and flaring events should be simplified. API suggests that the GOR be determined using an appropriate standard industry practice or method published by a consensus-based standards organization for a representative sample of wells within the Sub-basin entity whose associated gas is vented or flared.

Response: EPA understands that the GOR from each well is periodically monitored by oil and gas operators. Also, in today's final rule EPA has clarified that it is not requiring any new measurements unless no data is available. Hence, EPA has determined that there is sufficient flexibility available to reporters to estimate emissions with minimal burden. Therefore, EPA has retained the requirements for GOR determination from the proposed rule for estimation of emissions from individual wells.

13.2.6 BLOWDOWN VENT STACKS

Comment Number: EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
The final example is related to blowdown vent stacks. There are a limited number of tasks in the natural gas industry that result in blowing down significant volumes of natural gas to the atmosphere. These activities are limited to blowing down compressors, process vessels and piping. There are other tasks in the natural gas industry that result in blowing down very small and insignificant volumes of natural gas, such as blowdowns from sight glasses and small tubing. Without thresholds which limit the blowdowns that must be recorded, calculated, and reported, this portion of the proposed Subpart W will be unmanageable. GPA recommends that GHGs only from the following blowdowns be reported: 1) all compressor blowdowns and 2) blowdowns from process vessels & piping with a physical volume of 50 cubic feet and larger.

Response: EPA does not agree with the commenter on limiting blowdowns to compressors only. There are other vessels that when blown down result in large emissions, which EPA intends to capture. However, EPA agrees with the commenter on providing an equipment threshold. EPA conducted its own analysis which indicates that the 50 cubic feet equipment threshold is reasonable. Please see "Equipment Threshold for Blowdowns" memo in rulemaking docket EPA-HQ-OAR-2009-0923 for further details. Hence, in today's final rule, EPA has provided a 50 cubic feet equipment threshold. Reporters do not have to report blowdown emissions from any blowdown volume below this equipment threshold.

Comment Number: EPA-HQ-OAR-2009-0923-0582-37
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>**Comment Excerpt Text:**</u>
Blowdown Vent Stacks

Source Description: Natural gas emissions can occur whenever equipment such as a compressor are blowndown – that is the pressurized gas contained in the equipment is released to the atmosphere, sent to a vent stack or control device such as a flare. Routine shutdowns for maintenance and emergency shutdowns both result in release of natural gas.

Measurement Options: The approach recommended by USEPA was considered to be implementable without undue burden and sufficiently accurate to support a cap and trade rule. No other options were evaluated by WCI.

USEPA Approach: USEPA provides the following calculation methodology for blowdown stack vent emissions.

Step 1: Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels. Variable V [subscript v] in equation below.

Step 2: Record the number of blowdowns for each equipment type (N in equation below), and

Step 3: Calculate annual venting emissions using the following formula:

E [subscript a, n] = N * V [subscript v] (Eq. W-10)
Where:

E [subscript a, n] = annual natural gas venting emissions at ambient conditions from blowdowns in cubic feet
N = number of blowdowns for the equipment in the reporting year
V [subscript v] = total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves, in cubic feet.

Step 4: Calculate natural gas volumetric emissions at STP using calculations in paragraph (t) of this section

Step 5: Calculate CH_4 and CO_2 volumetric emission using methods in paragraph (u)

Step 6: Calculate CH_4 and CO_2 mass emissions using methods in paragraph (v) of this section.

WCI Recommendation: We recommend using the approach provided by USEPA without any modification.

Response: EPA has made modifications to the blowdown methodology to allow for the estimation of blowdown volumes with differing temperature and pressure conditions. With regard to modifications in equations for blowdown vent stacks, please see the response to EPA-HQ-OAR-2009-0923-1011-41.

Comment Number: EPA-HQ-OAR-2009-0923-1011-12
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
XII. Proposed Rule Section 98.233(i) Blowdown vent stacks.—El Paso requests that an alternate method be added to allow blowdown volumes be corrected to standard conditions for each event prior to aggregation.

Response: EPA agrees with the comment. With regard to modifications in equations for blowdown vent stacks, please see the response to EPA-HQ-OAR-2009-0923-1011-41.

Comment Number: EPA-HQ-OAR-2009-0923-1011-41
Organization: El Paso Corporation
Commenter: Fiji George
<u>Comment Excerpt Text:</u>
XII. Section 98.233(i) Blowdown vent stacks

The proposed regulation requires first aggregation of blowdown volumes at actual conditions from all events at the facility and then the conversion of the total volume to standard conditions. The regulation fails to take into account that each blowdown event may occur at a different pipeline pressure and a different gas temperature. In practice, the blow-down volumes are corrected to standard conditions for each event and then aggregated. Having the order of calculations as proposed would result in having to use a pressure of MAOP (Maximum Allowable Operating Pressure) and perhaps yearly average temperature at the site which would probably result in an over predictions of the blowdown volumes. Therefore, El Paso recommends that the reporters be allowed to correct the blowdown volumes to standard conditions on a per event basis.

Further, the proposed methodology is based on an assumption that the total volume between the isolation valves is blowdown. In practice, frequently a blowdown continues only until a desired working pressure is achieved. The desired working pressure may differ for each blowdown event depending on the reason for the blowdown. Therefore, treating each blowdown event individually and considering the initial and ending pressures will result in more accurate emission estimates.

It should be noted that many companies currently employ algorithms and programs to calculate and document blowdowns, and these methodologies use the same ideal gas law principles as intended by the Subpart W equations to calculate “event-based” blowdown volumes. Companies currently employing equivalent methods should be allowed to use their methodologies for the purpose of reporting GHG emissions under Subpart W.

In addition, El Paso recommends an option be provided for the installation of permanent meters on blowdown vent stacks.

Response: EPA agrees with the commenter with respect to different blowdowns being at different operating pressures. EPA has revised today’s final rule equation for blowdowns to account for different blowdown volumes at different pressures.

In today’s final rule, EPA clarifies that the blowdown volumes to be reported are for complete blowdowns to atmospheric pressure when equipment is being taken out of service, and does not include operating pressure adjustments. This means that any equipment and associated vessels and pipelines that vent gas to the atmosphere to bring actual pressure back to operating pressure do not report the resultant emissions. This clarification has been provided in today’s final rule. Given the clarifications and corrections, EPA determined that the calculation methods based on equipment volume are uniform across many reporters, sufficiently accurate, and cost-effective to estimate and report blowdown emissions. Hence, EPA has not allowed for any new methods or for installation of meters to determine blowdown emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1018-31
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
98.233 (i)(3): CAPP recommends that equation W-10 be a summation of all individual blowdown events as the volume blown down will change because it is unlikely that the whole piping assembly will be blown every event. Additionally the summation would be required to determine the "average" volume.

Response: EPA is not clear on the commenter’s request for change. If the commenter has multiple sections of the system that are blow down at different intervals then EPA has made the necessary changes to the equation to allow for summation of different blowdown volumes. If unique chamber volumes are blowndown in separate events, then the volume between isolation valves will have to be calculated separately for each unique volume. In addition, EPA requires reporting of total annual venting emissions for each equipment type as specified under Section 98.233(i)(3) of today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1039-10
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>

Errors in Section Labeling Should Be Corrected

The Proposed Rule includes a typographical error in the section hierarchy for the blowdown calculation section. The Proposed Rule indicates this subsection is §98.233(h)(iii); this subsection should be §98.233(i). This error is not found in the pre-publication version of the Proposed Rule, but is in the Federal Register version of the Proposed Rule. There is a related section hierarchy error in §98.233(h), where the first subsection is labeled (h)(i). The proper "subsection" protocol is to migrate from letters to numbers to (i), (ii), etc. Thus, §98.233(h)(i) and (ii) should be labeled §98.233(h)(1) and (2).

For clarity, INGAA provides appropriate revisions to the erroneous "§98.233(h)(i) – (iii)" text from 75 FR 18640:

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

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

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

Response: EPA agrees with the comment about the typographical error in the middle column of 75 Fed. Reg. 18640 and has made necessary corrections to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1039-11
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Emission Calculation Flexibility Should Be Provided

Subpart W should allow flexibility in documenting the emission calculations. Many companies currently employ algorithms and programs to calculate and document blowdowns, and these methodologies use the same ideal gas law principles as intended by the Subpart W equations to calculate "event-based" blowdown volumes. Companies currently employing analogous equivalent methods would document the calculation basis and Subpart W equivalence in their GHG Monitoring Plan. This could include an approach that calculates the gas volumes for individual venting events and sums the event volumes to determine annual emissions. For blowdowns of equipment where process conditions (e.g., blowdown beginning and/or ending pressures) vary for different events that occur in a year, this approach would provide a more accurate emission estimate than the Proposed Subpart W equations which assume the process pressure change and temperature are the same for each blowdown

Response: After considering several comments, EPA has made modifications to the blowdown methodology to allow for the estimation of blowdown volumes with differing temperature and pressure conditions. With regard to these modifications in equations for blowdown vent stacks, please see the response to EPA-HQ-OAR-2009-0923-1011-41.

The commenter has not provided sufficient details on the other methods that it intends to use. Hence EPA does not have any comment on these other methods. Finally, EPA determined that the engineering calculation methods in today's final rule are sufficiently simple and low cost to estimate and report blowdown emissions. Hence, EPA has not allowed for any new methods to estimate blowdown emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1039-12
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Equations for Blowdown Volume and Volume Correction to Standard Conditions Require Revisions

Corrections to equations and nomenclature presented in §98.233 are needed to correct calculations and to properly represent blowdown pressure changes and associated volumes:

•As currently written in §98.233, "Ea,n" in equation W-10 should be defined as, "Annual natural gas venting emissions at ambient process conditions from blowdowns in cubic feet." That is, the gas inside the vented equipment is at process temperature and pressure. The gas is not at ambient conditions.

• The §98.233 pressure correction calculation in Equation W-20 is not correct for blowdown emission estimates. The pressure parameters are "ambient" and "standard" conditions in Equation W-20, whereas the relevant pressures are ?P – the system/process gas pressure change during the blowdown – and standard pressure. That is, the system pressure change from event start to finish is not the same as "ambient" and "standard" in Equation W-20, and the equation to correct volumes to standard conditions requires revision.

• Thus, Equation W-10 could be revised to eliminate a separate calculation (i.e., Equation W-20) to correct to standard conditions via the following formula: [See original comment for equation]

Where:
Es,i = volume of gas vented, at standard temperature and pressure, from event i;
Vi = total geometric volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves in cubic feet;
PI = initial equipment gas pressure; i.e. gas pressure at the start of the blowdown;
PF = final equipment gas pressure; i.e. gas pressure at the end of the blowdown;
PSTD = standard gas pressure (14.7 psi);
TSTD = standard gas temperature (60°F);
TP = process gas temperature (°F); and
Es = annual volume of gas vented, at standard temperature and pressure, from the equipment.

With the above revisions, the result is at standard conditions and Equation W-20 would not be needed to calculate emissions at standard conditions. Note that these estimation equations do not consider the non-ideal gas behavior of natural gas at various pressures (i.e., equations do not include the compressibility factor "z") and assume the process temperature does not change during the venting (i.e., the initial and final process temperatures are the same). These are standard assumptions for calculating vented volumes. In general, the effects from these parameters will typically be small relative to pressure changes, but in some cases may be included in company algorithms and programs for more rigorous calculations.

If EPA makes alternative revisions to Equation W-10 to determine vented volumes at other than standard conditions and retains the reference to Equation W-20, then Equation W-20 must be revised so that corrections to standard conditions can consider the "scenario" pressure and temperature, which may be at process conditions or ambient pressure and temperature. Currently, Equation W-20 only provides a means to correct from ambient conditions to standard conditions. While INGAA has not reviewed requirements for all industry segments in the Proposed Rule, INGAA expects there are additional rule references to §98.233(t) and Equation W-20 that reflect similar anomalies. EPA should reconcile other anomalies or reference conditions (e.g., process versus ambient conditions for volume calculations) that introduce errors

Response: EPA agrees with the commenter on the errors in the equation to estimate blowdown emissions. In today's final rule, EPA has corrected the equation to use inputs at actual conditions and provide an output at STP conditions. EPA would like to note that the compressibility factor is 1 because of the assumption that ideal gas law holds at actual operating conditions. This approximation will not result in any significant errors in calculations, but will simplify the calculation method. Please see response to EPA-HQ-OAR-2009-0923-1011-41 for further clarifications in the monitoring method.

Comment Number: EPA-HQ-OAR-2009-0923-1039-15
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Safety Must Be Considered and Alternatives Provided for Inaccessible Vents

Safety is an extremely important concern when attempting to collect measurements from roofline vents at transmission compressor stations. At existing facilities, most vents are routed outside the compressor building and elevated above the roof line to disperse vented gas. Similarly, there are safety concerns associated with vent access for condensate tank vents at some facilities. Resolving these safety concerns will likely require modifications to provide vent access at a safer location. However, line accessibility (e.g., within the compressor building) may not be readily available as the facilities were not constructed considering these criteria. Due to an aggressive proposed implementation schedule, this would put operators at risk of failing to comply with the annual survey requirement, or placing personnel in harms way – i.e., violating safety procedures. Additional time should be provided to implement the vent measurement program so that modifications can be made to accommodate measurement from a safer location than from a building roofline or difficult to access condensate tank vent.

Safety concerns and vent measurement issues are exhibited in a photograph from a recent pilot study shown in Figure 1. To reach the roofline vents, the picture shows the manlift extended to maximum length and precariously suspended above high-pressure natural gas lines. This measurement should not have been pursued and cannot be mandated, as it creates unsafe conditions for workers and our facilities. In addition, vent locations require manlift placement in areas not designed for that use, resulting in significant destruction of walkways and the pipeyard grounds at this facility. For this pilot study, even with unacceptable manlift use, not all vents could be accessed and were therefore not measured.

Figure 1. Manlift Use for Roofline Vent Access Can Introduce Significant Safety Concerns.[See original comment for Figure 1]

In addition to the safety issues clearly shown in the above figure, vent measurement also introduces safety concerns by placing personnel in proximity to vents that are potential release points if an unplanned emergency blowdown were to occur. Even if safe access is achieved, additional safety concerns exist regarding roofline vent measurement. Facility safety requirements preclude the testing of a functioning pressurized compressor relief valve vent that could potentially discharge during measurement activities, thus placing personnel in a potentially flammable or explosive environment. To address this issue, process and procedural modifications would be required to eliminate the potential for an emergency blowdown. Implementation would be costly and complex.

The majority of building roofline vents and some condensate tank vents would be deemed inaccessible under conventional LDAR programs, as such components would be considered unsafe or difficult-to-monitor in a typical LDAR program (e.g., components that cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface). Under a typical LDAR program, monitoring can be deferred due to unsafe or difficult-to-monitor components. In response, the facility must maintain documentation that explains the conditions under which the components become safe to monitor or no longer difficult to monitor. For vent lines at most compressor stations, typical conditions under which these vents would be “safe” would preclude normal engine operations or pressurized scenarios where the potential for a vented release is possible. References are available from several rules that require VOC reductions through LDAR programs. Examples include the following:

• 40 CFR 60, Subpart VVa addresses performance standards for VOC leaks from chemical manufacturing and provides criteria for addressing access and safety issues including these examples:

- §60.482-7a(g) identifies a valve as “unsafe” to monitor if:

“The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying… [with leak monitoring requirements]”;

- §60.482a-11a(f) identifies “inaccessible” and “unsafe” connectors:

“(f) Inaccessible, ceramic, or ceramic-lined connectors . (1) Any connector that is inaccessible … is exempt from the monitoring requirements … and from the recordkeeping and reporting requirements …. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:
…

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;
(
v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.”

• §60.486a(f) includes provisions for documenting and retaining records for components that are unsafe or difficult to monitor.

There are additional examples from similar performance standards for VOC leaks. These criteria regarding inaccessible and unsafe-to-monitor components apply to many vents at transmission and storage facilities, and it is clear that regulated VOC sources have allowances for inaccessible components. Similar criteria should be applied to address vent access under Subpart W.

Implementation also requires additional training and expertise. Access to elevated vents requires test personnel to obtain fall protection training and annual certification. Physical access to the majority of reciprocating compressor rod-packing vents requires a manlift or a ladder on an elevated walkway grate that is typically located above high pressure discharge yard piping. A certified manlift operator is required to safely position the manlift bucket to properly access and measure vented gas volumes. Facility grounds in proximity to these locations may not be conducive to manlift siting, and care must be taken to avoid uneven ground, drop offs, holes, adjacent structures, pipe racks, and overhead obstructions. Weather and surface conditions can also significantly affect the ability to properly position the manlift. These access restrictions present a considerable safety risk, which could lead to reassessment of insurance liability. In addition, facility and tank configuration for gas transmission condensate tank vents may present similar access problems at some facilities. Clearly, there will be instances when vent access is not possible and/or would violate accepted safety practices.

INGAA members are currently pursuing alternative sample points at safer vent measurement locations. However, accessibility will be an issue at some facilities, and this will not be a trivial matter when Subpart W is implemented across the nation’s transmission pipeline system. There is no reasonable basis to impose an implementation schedule that requires operating a manlift unsafely just to acquire a mandated measurement.

As discussed in Comment XII, additional time should be allowed to implement Subpart W. Furthermore, allowances must be provided in the Final Rule if facility design precludes reasonable access to vent lines or condensate tank vents at a safe measurement location. Operators should not be required to pursue extraordinary facility modifications, such as costly re-design and modification to existing infrastructure, only for the purpose of vent access. In these instances, operators should be able to identify inaccessible vents within the GHG Monitoring Plan, as well as include the basis for such judgments and explanation as to the infeasibility of alternative vent line access. “Best available” data options should be allowed for emissions estimates under these cases. INGAA offers its assistance to work with EPA to define a reasonable basis to ensure inventory integrity, while considering important safety issues regarding vent accessibility

Response: EPA considered all methods for quantifying equipment leaks and vents. All methods proposed in today’s final rule have been demonstrated in practice in operating facilities, and are considered safe to perform by trained technicians. EPA agrees with the commenter that safety must be a first consideration in all emissions measurement activities and in certain unique cases, the methodologies as outlined in the proposed rule may pose a safety hazard. Therefore, for compressor vent emissions where roof vents are not positioned in a location that is safe to access the end of the pipe, the rule allows for a piping modification to install a port for insertion of a flow measuring instrument, or installation of a permanent flow measurement instrument. In those cases where this modification cannot be made for a particular equipment configuration, the reporter may petition EPA for an extension of time under the BAMM provisions in today’s final rule. Please see Section II.F of the preamble to today’s final rule for further details.

EPA also agrees with the commenter’s point about inaccessible emissions sources from condensate tanks in gas processing facilities and transmission compressor stations. In today’s final rule, EPA has determined that condensate tanks in processing facilities do not contribute enough emissions to warrant the cost of quantification, and therefore this source is not required to be reported.

In gas transmission compressor stations, EPA has included in today’s final rule the alternative of using an acoustic leak detection instrument that has algorithms for through-valve leak quantification to estimate compressor scrubber dump valve leakage as an alternative to measuring the emissions from the tank roof vent. This alternative acoustic through-valve leak measurement technique is also added in today’s final rule for compressor blowdown vent through-valve leakage. Because the blowdown vent valve must be accessible to operate, this acoustic detection alternative would be more cost-effective and safe to employ for this emission source quantification.

Comment Number: EPA-HQ-OAR-2009-0923-1039-9
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Blowdown Venting

Subpart W annual emission estimates for equipment blowdowns are calculated from the volume of gas vented during each event and the number of events per year. The volume of gas vented is determined from the vented equipment internal geometric volume with corrections for pressure and temperature to standard conditions.

In general, INGAA accepts the proposed method in §98.233(i) for estimating equipment blowdown emissions, but INGAA recommends minor revisions to add clarity and correct erroneous references and formula errors – the Subpart W calculation of vented gas volume at standard conditions (equation W-10 and equation W-20) is not correct and requires revision. In addition, flexibility in documenting the emission calculations is needed.

Response: EPA has made modifications to the blowdown methodology to allow for the estimation of blowdown volumes with differing temperature and pressure conditions. With regard to these modifications in equations for blowdown vent stacks, please see the response to EPA-HQ-OAR-2009-0923-1011-41.

Comment Number: EPA-HQ-OAR-2009-0923-1061-12
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
Blowdown vent stack requirements should be clarified. In the middle column of 75 Fed. Reg. 18640 there are requirements set forth for blowdown vent stacks. Those provisions are numbered (iii) but in fact should be numbered (i). There is currently a lack of clarity as to what items must be subjected to calculation pursuant to these provisions, given the proposal's ill-advised use of "including but not limited to" in the applicability section of the rule. There are hundreds of items that could be covered by a rule that covered calculation of "total volume . . . between isolation valves," such as sample bottles, sight glass, control tubing, and the like. We expect that EPA does not intend for such de minimis sources to be subject to calculation, and we suggest that the rule be amended to provide for a de minimis level of 5 mcf below which calculation of individual items such as mentioned above need not be performed. In addition, we believe that subparagraph (1) should be amended as follows:

"(1) Calculate the total volume (including, [strike through: but not] limited to, [strike through: pipeline] process piping, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves."
These changes will add clarity for regulated companies and will eliminate unnecessary and onerous reporting of very insignificant sources.

Response: EPA agrees with the comment. Today's final rule provides an equipment threshold below which emissions do not have to be reported. Please see response to EMAIL-0002-8 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923) for further details and the memo on the “Equipment Threshold for Small Combustion Units” under docket EPA-HQ-OAR-2009-0923.

In today’s final rule, EPA has also accepted the correction suggested by the commenter to the calculation of total volume between isolation valves.
EPA also agrees with the comment about the typographical error in the middle column of 75 Fed. Reg. 18640 and has made necessary corrections to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1074-13
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment: WBIH strongly requests measurement of emissions from rod packing, blowdown valves, and blowdown vents be conducted in one mode, the mode existing at the time of the measurement.

In order to conduct measurements in the compressor de-pressurized mode, a compressor blowdown would be required, resulting in additional emissions. Additionally, in the compressor de-pressurized mode, the compressor is not available for service creating an interruption of service to customers
Response: EPA never intended for operators to depressurize their compressors to estimate emissions in that mode. Please see the response to EPA-HQ-OAR-2009-0923-0055-16 for further details on EPAs revised monitoring requirements for compressors.

Comment Number: EPA-HQ-OAR-2009-0923-1074-31
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.233 (75 FR 18640) for "Blowdown vent stacks":
Correct the identification reference from "iii" to "i".

Response: EPA agrees with the comment about the typographical error in the middle column of 75 Fed. Reg. 18640 and has made necessary corrections to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1080-23
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>

Aka recommends that GHGs from only the following blowdowns be reported under §98.233(i): (1) all compressor blowdowns; and (2) blowdowns from process vessels and piping with a physical volume of 50 cubic feet and larger.

Response: EPA agrees with the commenter on reporting all compressor blowdowns and on providing an equipment threshold. With regard to blowdown vent stack emissions requirements and equipment threshold, please see the response to EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1151-35
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(i) Blowdown vent stacks. In Section 98.233(i)(2), logs of the number of blowdowns for each equipment type are required to be maintained. While a record of blowdown occurrences is usually kept for larger types of equipment such as compressors greater than 500 hp, keeping records of blowdowns for the numerous small pieces of equipment is impractical. API recommends engineering estimates be used for the number of blowdowns for compressors less than 500 hp and equipment other than compressors. The engineering estimate methods would be described in the monitoring plan.

Response: In today's final rule EPA has modified blowdown vent stacks emissions requirements and provided an equipment threshold. For further clarification, please see the response to EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1155-25
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Blowdown Vents (Natural Gas or CO2 Enhanced Oil Recovery Operations)

We support EPA's proposed emission estimating method for blowdown vents that is based on the number of blowdowns and the volume of the blowdown equipment chamber.

Response: EPA has made a minor modification to the blowdown methodology to allow for the estimation of blowdown volumes with differing temperature and pressure conditions and also provided an equipment threshold. Please see the responses to EPA-HQ-OAR-2009-0923-1011-41 and EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1206-37
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
§ 98.233(e)(3): This requirement addresses emissions during depressurization of a solid media dehydration vessel. These emissions are already covered by Section 98.233(i), and this section should be deleted to avoid double reporting. Also, there is a typo on page 18640. The section that should be labeled “98.233(i) Blowdown Vent Stacks” is mislabeled as “98.233(h)(iii).

Response: EPA assumes that by “solid media dehydration vessel” the commenter means dessicant dehydrators, in which case EPA agrees that the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002) would have resulted in double counting of emissions. EPA has clarified in today’s final rule that desiccant dehydrators must report under the dehydrator vent source type.

EPA agrees with the comment about the typographical error in the middle column of 75 Fed. Reg. 18640 and has made necessary corrections to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1298-37
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Blowdown vent stacks

Section 98.233(i): There are a limited number of tasks in the natural gas industry that result in blowing down significant volumes of natural gas to the atmosphere. These activities are limited to blowing down compressors, process vessels, and piping. There are other tasks in the natural gas industry that result in blowing down very small and insignificant volumes of natural gas, such as blowdowns from sight glasses and small tubing. Without thresholds that limit the blowdowns that must be recorded, calculated, and reported, this portion of Subpart W is unmanageable. IPAMS requests that only GHG emissions from the following types of blowdowns be reported: 1) compressor blowdowns, and 2) blowdowns from process vessels and piping with a physical volume of at least 50 cubic feet.

Also note that this section was incorrectly positioned in the proposed rule as Section 98.233(h)(iii); the correct section should be labeled as Section 98.233(i).

Response EPA does not agree with the commenter on limiting blowdowns to compressors only. However, EPA agrees with the commenter on providing an equipment threshold. Please see response to EMAIL-0002-8 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923) for further details.

EPA agrees with the comment about the typographical error in the middle column of 75 Fed. Reg. 18640 and has made necessary corrections to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1305-21
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(i) Blowdown vent stacks

In Section 98.233(i)(2), logs of the number of blowdowns for each equipment type is required to be maintained. While a record of blowdown occurrences is usually kept for larger types of equipment such as compressors, keeping records of blowdowns for the numerous small pieces of equipment is impractical. BP recommends engineering estimates be used for the number of blowdowns for equipment other than compressors.

Response: After considering several comments, EPA has modified blowdown vent stacks monitoring requirements and provided an equipment threshold that will mitigate commenter concern for non-large equipment blowdown emissions. However, EPA does not agree that the source be limited to compressors only. For further details, please see response to EMAIL-0002-8 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-3522-5
Organization: Heath Consultants
Commenter: Milton W. Heath

Comment Excerpt Text:
Blow-down Systems: A Blow-down system is typically designed at an elevated height in order to safely vent high pressurized gas away from the gas facility which can be done when compressors are placed offline due to changing operational demands or for purposes of conducting maintenance. The areas of venting where the blow-down event occurs can be 12 – 60 feet off the ground and not easily accessible. Gas may also be escaping through these stacks or vents because of leaking seals whereby internal valve leakage can also vent safely to atmosphere. Conventional methods used to screen these vent systems have included using a long extension probe (telescopic, see figure 1 below) to pull a sample of air into a pump driven combustible gas indicator (using catalytic oxidation / thermal conductivity hydrocarbon sensors) or infrared leak detectors in order to determine gas concentration as a percentage of volume gas or parts per million. The gas imaging camera does offer some advantage in screening these difficult to reach systems because you can view the stack from the ground and make a determination from the image viewed in the display. However, the gas imaging camera does not offer any additional information on the gas leak such as gas concentration or leak rate.

The gas imaging cameras costs anywhere from $85,000 – $105,000 and are heavily dependent on user experience and expertise. There is a looming dilemma with the use of these cameras in that the utilization of them becomes more subjective from user to user. What one user may see through the lens of a camera, another may completely miss because they did not adjust the image to the proper polarity and enhance the sensitivity. Weather conditions, temperature and cloudiness will affect whether or not a gas plume can be properly and adequately imaged which invite potential problems for gas companies who may later be audited and asked to account for missed gas leaks.

Other pitfalls with the imaging camera include the question on what to do with the stored image files and how to properly manage this piece of information. It will take a great amount of time and attention to detail in tracking this information and applying it to a database against a known or clearly identified component in the system.
Operators will be subject to fatigue with this device as it requires enormous mental focus and physical strength to first stabilize the camera, scan the area, adjust the settings and determine whether a leak plume is present or not.

Most of these considerations are removed with the use of readily available, proven, much more affordable leak detection technologies which are manufactured not by one single company, but multiple manufacturers in the United States and abroad. A picture below is provided as an example of a safe, reliable, accurate and fast method for screening blow-down systems which may include vents/stacks designed for blow down valves, main-line suction/discharge block valves or unit valves, pressure relief valves, power gas starter valves and emergency blow-down/shutdown valves.

Figure 1: Vent stack leak screening with an electronic gas leak detector, TVA/OVA or infrared gas detector. [See pdf attachment for photo]

Response:
EPA does not require leak detection for the blowdown emissions source type (Section 98.233(i) of today's final rule). Hence, the comment is irrelevant in the context of this source type. EPA requires the use of engineering estimation of blowdown emissions.

13.2.7 COMPRESSORS

Comment Number: EPA-HQ-OAR-2009-0923-1099-18
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Monitoring methods and emissions quantification for: Centrifugal Compressor Wet Seal Degassing Vents and Reciprocating Compressor Rod Packing Venting. The effort required to measure the emissions from centrifugal compressor wet seals and reciprocating compressor rod packings is extensive. The vents from these two pieces of equipment are combined with the vents of other pieces of equipment and are emitted from the blowdown vent stack away from the compressor. The individual vents for these two pieces of equipment are very difficult to access inside the compressor and the emissions from the blowdown vent are combined with other emissions. Breaking these vent headers apart inside the compressor building for measuring purposes can pose a safety hazard. It would be very difficult to measure emissions from the blowdown vent stack because it ranges from 1,000's of cubic factions of feet of gas per hour. The volume going thru the venting system when starting and stopping the compressor is very different when compared to times when the compressor is at idle. It would be very difficult to identify the emissions from a single particular piece of equipment. In lieu of measuring the gas from centrifugal compressor wet seals and reciprocating compressor rod packings, NMGC suggests requiring that companies demonstrate good maintenance practices of these pieces of equipment. If properly maintained, the emissions are very small. Requiring documentation of proper maintenance, i.e. regularly replacing them, is an incentive for companies to maintain the equipment properly which in turn will ensure emissions are minimal.

Response: EPA does not require compressors to be shutdown. Please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023). EPA does not require that vent manifolds be broken apart. Please see response to comment EPA-HQ-OAR-2009-0923-1039-13.

Comment Number: EPA-HQ-OAR-2009-0923-0133-6
Organization: Leak Surveys Inc.
Commenter: David Furry, President and Owner

Comment Excerpt Text:
Section 98.233 (p) (4) Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period: Our experience has shown that most of the large leaks found on compressors have occurred during operating mode. To image and measure all vents in all three operational modes will create a number of challenges associated with bringing compressors down and then back up which will result in excessive releases of methane, as well as the required man-hours associated with having the optical imaging crew on standby while compressors are brought down and back on-line.

Response: EPA disagrees with this comment. For more information please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1060-9
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Fugitive Emissions at Different Operational Modes. On page 43 of the Technical Support Document and in 98.233(p)(4), the EPA addresses fugitive emissions from compressor operations at different operational modes. In the Technical Support Document, the EPA concedes that to address this issue, operators must measure emissions for each mode the compressor is operated in and the duration of that operational mode and this will "increase the reporting burden, since measurements will have to be taken at each mode of compressor operation." Indeed – this requirement will greatly increase the reporting burden while not addressing a significant source of GHG emissions. 98.233(p)(4) requires measurement in several operational modes: Compressor engines are generally either operational or not. Some of the operational modes are not normally encountered and this would have to be artificially reproduced in the field for the sole purpose of reporting. A compressor would not standby pressurized for any amount of time that would affect its emissions significantly as it would otherwise be offset by the fact that the compressor is operational. Therefore, requiring measurement in each mode is burdensome, difficult to schedule, and does not reflect a significant source of emissions.

Response: EPA disagrees with this comment. For more information please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1080-27
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Aka recommends that industry not be required to measure emissions from "standby" or depressurized compressor units. These measurements will require the creation of GHG emissions in the depressurization of units and will add no useful data to the data set for most units.

Response: EPA disagrees with this comment. For more information please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1155-26
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

__**Comment Excerpt Text:**__
Compressor Emissions. We support EPA's proposed emission estimating method for reciprocating and centrifugal compressors that relies on direct measurement.

Response: EPA reviewed this this comment and has retained direct measurement of compressors in the rule.

Comment Number: EPA-HQ-OAR-2009-0923-1018-41
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

__**Comment Excerpt Text:**__
In 98.233(r)(2) CAPP questions the inclusion of "compressor starter gas vents" in equation W-19. Is the intent to capture methane emissions during starting events? If so, these emissions are a function of the number of starts per year (duration of only a few seconds each). If the intent is to capture emissions from periods when the engine is running and gas is passing through the starter to atmosphere, the calculation should reflect the calculation for an open-ended line as this is what most accurately represents the emission event.

Response: Upon further review of the large emissions sources as described in the Technical Support Document EPA-HQ-OAR-2009-0923, EPA has determined that compressor starter gas vents are not a significant source of GHG emissions. Therefore, EPA has removed compressor starter gas vents from the list of sources.

Comment Number: EPA-HQ-OAR-2009-0923-1151-45
Organization: American Petroleum Institute
Commenter: Karin Ritter

__**Comment Excerpt Text:**__
Section 98.233(r)(2) Population count and emission factors. API would like clarification on the inclusion of "compressor starter gas vents" under Equation W-19. Emissions from these vents are not a function of compressor operational hours, but rather are dependent on the number of starts per year whose duration only last a few seconds. In addition, this section refers to Table W-1 for a compressor starter gas vent emission factor, but such a factor is not listed in Table W-1. This emission source is also referred to as a fugitive source, but it is considered a vented emission source in the API Compendium.

Response: EPA has removed compressor starter gas vents from today's final rule. Please see response to comment EPA-HQ-OAR-2009-0923-1018-41.

Comment Number: EPA-HQ-OAR-2009-0923-1206-63
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Reporting compressor throughput: This section requires companies to report throughput for each compressor covered by Subpart W. Compliance with this requirement would require a flow meter to be installed on every affected compressor in the E&P sector. This requirement would be excessively costly because individual compressors typically are not equipped with flow meters, so countless new meters would have to be installed. Moreover, individual compressor throughput is data that is not useful to EPA for any reasonable policy or regulatory purpose. Thus, we recommend that this reporting requirement should be deleted. Alternatively, if EPA determines that compressor throughput is needed, that information should be provided on a per facility basis (i.e., as an aggregate for all compressor at a given facility rather than for each compressor individually) and throughput should be based on engineering estimates rather than direct measurement.

Response: Commenters made several assumptions which were not consistent with the proposed rule's intent. One was the assumption that each compressor would need a meter to determine compressor throughput. Reporters are not required to install a meter. EPA has clarified this in today's final rule and allows reporters to use engineering estimation to determine compressor throughput. EPA requires the compressor throughput for analysis of the activity data and the resultant GHG emissions reports, as combustion CO2 will be proportional to compressor throughput.

Comment Number: EPA-HQ-OAR-2009-0923-1024-35
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Reporting of Individual Compressor Throughput. The proposed rule appears to require reporting of total throughput of each individual compressor connected to a compressor wet seal degassing vent, as well as the total throughput of individual reciprocating compressors.[220] Kinder Morgan and other members of our industry generally do not monitor throughput at the level of individual compressors; rather, this data is collected at the compressor station level. Obtaining this data would be costly and difficult. Furthermore, Kinder Morgan believes this data would have little practical use for EPA, since the quantity of vented and fugitive emissions from compressors is not well correlated with throughput.

Response: EPA agrees that many companies do not monitor throughput and therefore EPA has modified to today's final rule to allow the use of engineering estimates. EPA disagrees with the

[220] Proposed 40 C.F.R. SECTION 98.236(c)(17)(iii), (18)(i).

comment that the data would have little practical use for EPA. For further information on both points, please see response to comment EPA-HQ-OAR-2009-0923-1206-63.

Comment Number: EPA-HQ-OAR-2009-0923-1016-44
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:
LNG Compression Equipment. LNG storage facilities use reciprocating and centrifugal compressors for a limited number of purposes, which include boil-off compression, and as refrigerant and boost compression in liquefaction processes. Compressors are not used to compress vaporized LNG to move to the send-out system, as described in the EPA's Background Technical Support document (see Exhibit C, Figures 1A, 2, and 3).

While reciprocating compressors at LNG storage facilities may appear similar externally to reciprocating compressors more familiar to EPA, such as those located at transmission compressor stations, compressors at LNG storage facilities are typically quite different internally, due to the materials utilized to seal piston rod packing to limit leakage past the piston rods. Reciprocating compressors used at LNG storage facilities for boil-off compression, liquefaction refrigeration compression and liquefaction stream boost generally utilize non-lubricated cylinders and rod packings to eliminate the risk of lubricants being introduced into the process gas stream causing contamination of the stream with oil residue, which would freeze the oil in critical components such as heat exchangers, operating at temperature as low as -260 degrees Fahrenheit. These non-lubricated applications typically utilize piston ring, and rod packing materials of varying graphite, PTFE (Teflon) blends which are very resilient and have high sealing qualities, thereby greatly minimizing fugitive leak emissions from the compressor rod packing cases.

Centrifugal compressors are typically utilized at LNG storage facilities as liquefaction process refrigerant compressors. Again, while externally they may resemble typical centrifugal compressors that are becoming more common in gas transmission compressor stations, these centrifugal refrigerant compressors are typically quite different internally with respect to their shaft sealing design, using very sophisticated oil film (wet) sealing or dry elements, which greatly reduce or eliminate leakage. The outer case seal areas and the seal oil drains are directed back to the compressor suction after demisting takes place. Because the outer case seal area and seal drains lead back to the compressor suction, there are no gases purposely vented to the atmosphere as the proposed rule assumes. All of the above discussion on compressors provides further evidence that LNG facilities are not contributing to the fugitive emissions concerns that this proposed rule is intended to minimize.
For example, reciprocating compressor rod packing has a certain level of emissions by design, e.g., there is a clearance provided between the packing and the compressor rod for free movement of the rod that results in emissions. Also, by design, vent stacks in petroleum and natural gas production, natural gas processing, and petroleum refining facilities release natural gas to the atmosphere. Unintentional emissions result from wear and tear or damage to the equipment. For example, valves result in natural gas emissions due to wear and tear from

continuous use over a period of time. Also, pipelines damaged during maintenance operations or corrosion result in unintentional emissions.

Response: EPA disagrees with this comment. EPA's decision to include LNG storage facilities was based on several considerations. Please see EPA's Greenhouse Gas Emissions from the Petroleum and Natural Gas Industry: Background TSD (EPA-HQ-OAR-2009-0923-0027) and response to comment EPA-HQ-OAR-2009-0923-1025-1 for EPA's analysis for including LNG storage in the rule. In addition, EPA is aware of different technologies for compressors deployed by industry across several sectors to reduce emissions. If this commenter is using low emission technologies, then EPA would expect to see such emissions reflected in their submitted report. However, the use of low emission technology is not known to be ubiquitous in the LNG industry and therefore the collection of GHG data from the LNG sector is important in understanding emissions from this sector and therefore does not entitle LNG storage facilities special considerations under this economy-wide GHG rule; as such information may demonstrate differentiated emissions levels, which would inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-1080-51
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Gathering compression facilities are typically small facilities and widely dispersed. Many of these compression facilities have only one or two compressors and may include treatment facilities, such as dehydration units. Significantly-sized facilities are already subject to Subpart C reporting if the combustion emissions exceed 25k tonnes per year ("tpy") and individual compression facilities that exceed 25k tpy, including Subpart W emissions, would also begin reporting as required. The proposed Subpart W, however, treats these small and widely dispersed facilities as if they are the same size and complexity of a gas processing plant. Examples of proposed requirements that may be appropriate for processing plants but unduly burdensome for small and widely dispersed gathering compression facilities include: collecting extensive data and modeling tank emissions, compressor rod packing vents, leak detection using optical imaging or population factors, and quarterly sampling of gas streams.

Response: Today's final rule does not include gathering and boosting stations. Please see Section II.F of the preamble to today's final rule.

13.2.7.1 CENTRIFUGAL COMPRESSORS

Comment Number: EPA-HQ-OAR-2009-0923-0133-4
Organization: Leak Surveys Inc.
Commenter: David Furry, President and Owner

Comment Excerpt Text:
Section 98.233 (o) Centrifugal compressor wet seal degassing vents. This section states that a

flow meter, either temporary or permanent, is to be used to measure emissions from ALL VENTS to the atmosphere or to the flare. If the compressor vent is connected to the flare, and the flare has a gas meter attached, this would result in double counting. We would also suggest that the optical imaging camera be used to first determine if the vent is leaking before moving forward. This would potentially save the expense of measurement, and would eliminate the safety hazard of using a man lift in and around the components.

Response: Commenters made several assumptions which were not consistent with the proposed rule's intent. One was the assumption that EPA required the double reporting of flare emissions calculated under each paragraph of the rule in §98.233 "Calculating GHG emissions," that requires flare emissions determination. Reporters are not required to double report flare emissions. EPA has clarified this in today's final rule and states that reporters must correct flare emissions to avoid double reporting. In addition, centrifugal wet seal degassing tank venting is by design, and therefore always occurs when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. Therefore, EPA disagrees with requiring the use of an optical gas imaging camera to detect seal oil degassing tank venting, because when the separated gas is vented to the atmosphere, by design, gas will be venting.

Comment Number: EPA-HQ-OAR-2009-0923-0958-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

<u>Comment Excerpt Text:</u>
It appears that you must calculate the volume of vapors sent to a flare or tank for centrifugal compressor wet seal degassing vents. Would this not be also reported under flares? Is this double reporting of emissions

Response: EPA disagrees with this comment regarding flare double reporting. Please see response to comment EPA-HQ-OAR-2009-0923-0133-4 above.

Comment Number: EPA-HQ-OAR-2009-0923-0582-38
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

<u>Comment Excerpt Text:</u>
USEPA Subpart W approach: The re-proposed Subpart W reporting regulation contains methods for both reciprocating and centrifugal compressors. These two methods are discussed below.
Centrifugal compressor wet seal degassing vents
Calculate emissions from centrifugal wet seal degassing vents as follows:
Step 1: For each centrifugal compressor determine the volume of vapors from the wet seal oil

degassing tank sent to an atmospheric vent or flare, using a temporary or permanent flow measurement meter, such as, but not limited to, a vane anemometer, according to the methods set forth in 98.234(b).
Step 2: Estimate annual emissions using meter flow measurement using Equation W-16 of this section.
E [subscript a, i] = MT * T * M [subscript i] * (1 – β) (Eq. W-16)
Where:
E [subscript a, i] = Annual GHG I (either CH_4 or CO_2) volumetric emissions at ambient conditions.
MT = meter reading of gas emissions per unit time
T = total time compressor associated with the wet seal(s) is operational in the reporting year.
M [subscript i] = mole percent of GHG i in the degassing vent gas; use the appropriate gas composition in paragraph (u)(2) of this section
β = percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel system
Step 3: Calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (t) of this section.
Step 4: Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.
Step 5: Calculate emissions from degassing vent vapors to flares as follows:
(i) Use the degassing vent vapor volume and gas composition as determined in paragraphs (o)(1) through (3) of this section.
(ii) Use the methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.
Reciprocating compressor rod packing venting. Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows:
Step 1: Calculate CH_4 and CO_2 volumetric emissions at ambient conditions as follows:

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

Where:
$E_{a,i}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions
MT = meter volumetric reading of gas emissions per unit time, under ambient conditions
T = total time the compressor associated with the venting s operational in the reporting year
M_i = mole percent of GHG i in the vent gas; use the appropriate gas composition in paragraph (u)(2) of this section
Determination of gas emission rate (MT)
If the rod packing case is connected to an open ended vent line then use one of the following two methods to calculate emissions.
(i) measure emissions a from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in §98.234 (c).
(ii) use a temporary meter such as, but not limited to, a vane anemometer, or a permanent meter such as, but not limited to, an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in §98.234(b). If the rod packing case is not equipped with a vent line, use the following method to estimate emissions: (i) You must use the

methods described in §98.234(a) to conduct annual leak detection of fugitive emissions from the packing case into the distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
(ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in 98.234(d).
Measurement frequency (MT)
Conduct one measurement for each compressor in each of the operating modes that occurs during a reporting period:
(i) Operating
(ii) standby pressurized
(iii) not operating, depressurized.
Step 2: Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section
Step3: Estimate CH_4 and CO_2 volumetric emissions and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.
WCI Recommendations: WCI recommends adopting the USEPA methodologies for reciprocating and centrifugal compressors with no modifications. Both these methods utilize direct measurement of emissions which will provide accurate, cap-and-trade quality emissions quantification for compressors in gas processing plants.

Response: EPA has revised today's final rule for compressor monitoring. Please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1011-43
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(o) Centrifugal compressor wet seal degassing vents
Section 98.233(o) does not currently prescribe that wet seal vents be surveyed in each of the operational modes that occur during a reporting period (as does for reciprocating compressor vents). But the TSD[221]does acknowledge these emissions differ in various operating modes. Therefore, it is not clear if it was the EPA's intent to have the three mode requirement apply to centrifugal compressors. El Paso requests clarification on the requirement to survey in various modes of operation. (Note that because centrifugal compressors with wet seals cannot remain pressurized when offline, only two modes of operation are possible: operating and not operating, depressurized.) If this requirement was intended to apply, El Paso recommends that centrifugal compressors with wet seals be surveyed as per the "As Found" approach described under Section XV and that emission factors be calculated as presented in Table 7 below. Table 7 presents a sample calculation of the annual leak rate from a wet seal centrifugal compressor unit that is blown down when off line. In this example, hypothetical emission factors are used to represent

[221] See Appendix M of the Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document, page 160.

the key sources. This example also assumes that the compressor unit in question has one compressor wet seal, one blow down valve, one pressure relief valve, and one pair of unit isolation valves. Finally, the compressor unit is assumed to be "Operating" 75% of the year (6570 hours) and "Not Operating, Depressurized" the remaining 25% of the year (2190 hours). Therefore, as shown in Table 7, to calculate the contribution of wet seal leakage while the compressor unit is operating, the hypothetical emission factor for "Operating" wet seals (120.0 scfh CH_4) is multiplied by the number of wet seals (1) and again multiplied by the activity factor (6570 hours per year that the compressor is in "Operating" mode). This result was then divided by 1000 to convert to Mcf/yr (Mcf = 1000 cubic feet in US natural gas industry terminology) resulting in 788 Mcf CH_4/year. Similar calculations are made for each of the other component categories, with the results from each category being totaled to calculate the overall annual compressor unit leak rate. Note that in practice, emissions will be calculated by using a combination of unit specific measurement data and operating company emission factors. Actual measurement data will be used for each unit as available, and the emission factors will be used to project leakage from the mode which was not measured. This will make the calculations more facility specific.

Table 7: Sample Calculation of Emissions from a Centrifugal Compressor Unit With Wet (Oil) Seal (Basis: 75% Utilization)

Component	Component Emission Factor (scfh CH_4)	No. of Components	Activity Factor (Hours Leaking/Yr)	Annual Emissions (Mcf CH_4/Yr)
Compressor Status: Operating				
Wet (Oil) Seal – Operating	120	1	6570 Hours (Operating)	788
Pressure Relief Valve	102.6	1	6570 Hours (Operating)	674
Blow Down Valve	10.1	1	6570 Hours (Operating)	66
Compressor Status: Not Operating, Depressurized				
Unit Isolation Valve Pair	1100	1	2190 Hours (Blown Down)	2409
Total Annual Emissions (Mcf CH_4/year)				**3938**

Response: EPA has clarified the modes in which compressors must be measured and corresponding methodologies in today's final rule. For more information please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1011-14
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Proposed Rule Section 98.233(o) Centrifugal compressor wet seal degassing vents.—El Paso requests clarification on the operating mode requirements for surveys of centrifugal wet seal vents. It is our interpretation that Section 98.233(o) does not currently prescribe that wet seal vents be surveyed in each of the operational modes that occur during a reporting period.

Response: EPA has clarified the modes in which compressors must be measured and corresponding methodologies in today's final rule. For more information please see Section II.F of the preamble to today's final rule and "Compressor Modes and Threshold" (EPA-HQ-OAR-2009-0023).

Comment Number: EPA-HQ-OAR-2009-0923-1039-13
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Centrifugal Compressor Wet Seal Degassing Vents § 98.233(o) defines emission estimates for centrifugal compressor wet seal degassing vents based on annual measurement of the wet seal oil degassing tank vent. In general, INGAA accepts the proposed vent measurement requirements for wet seal degassing, with the request that the following three issues be addressed in the Final Rule:
• As discussed in Comment VI, operators should be allowed to elect to conduct direct measurement of common vent lines, where applicable, and report the actual annual volume measured;
• In addition to flow measurement meters prescribed in the Proposed Rule, alternative tools for vent gas measurement should be allowed, provided that the vented rate is within an acceptable range of the instrument. These alternatives should include calibrated bags (§98.234(c)) and high-volume samplers (§98.234(d)); and
• Engineering units should be provided for parameters in equation W-16 and these units should be consistent with the referenced calculations in §98.233(t) and §98.233(v). This issue is highlighted here, and a similar general statement is provided in Comment XIII regarding review and correction of equations, especially broadly-applied equations such as those in §98.233(t) and (v).
Furthermore, as discussed in Comment X, reporting individual compressor throughput is not feasible or practical and should be deleted from the Rule

Response: EPA disagrees with this comment that centrifugal compressor venting be allowed to only conduct direct measurement of common manifolded vent lines. The rule allows installation of a port on each vent line to the manifold, for insertion of a temporary meter, and these ports can be installed at ground level. Typically, centrifugal compressor venting emissions vary with the mode of operation of the compressor. Generally, the emissions are highest when the compressor is operating and lower when they are in the not operating depressurized mode. However, when the compressor is not operating depressurized, there may be leakage of natural gas through the unit isolation valve, particularly if the valve seat has become fouled and will not completely close. Hence to correctly characterize annual emissions from centrifugal compressors, estimation of emissions in two compressor modes, operating, and not operating depressurized is required. A temporary meter such as vane anemometer or permanent meter such as orifice meter can be used to measure emissions from the vents. EPA disagrees with allowing measurement of seal oil degassing vent emissions with calibrated bags or high-volume samplers, because the volume of gas from the degassing tank vent is typically well in excess of the capacity of these measurement devices. EPA agrees with the comment to add engineering units to the equation for centrifugal compressors, and has revised today's final rule.

Commenters made several assumptions which were not consistent with the proposed rule's intent. One was the assumption that each compressor would need a meter to determine compressor throughput. For more information, please see response to comment EPA-HQ-OAR-2009-0923-1206-63.

Comment Number: EPA-HQ-OAR-2009-0923-1151-81
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(o) Centrifugal compressor wet seal degassing vents. The variable Mi in Equation W-16 should be a volume percent of GHG to make the units work out.

Response: EPA disagrees with this comment to change the variable Mi in this equation to volume percent. The term "mole percent" has no units and neither does the term "volume percent". In either case, it would not be expected to make any difference to the units in the equation. If we consider the GHGs as near-ideal gases, then under that condition, the mole fraction (which is the same as mole percent) would be identical with volume percent (or volume fraction). Hence, no change is required for the variable Mi to make it volume percent.

Comment Number: EPA-HQ-OAR-2009-0923-1080-24
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>
Aka recommends that in Section § 98.233(o) the rule should allow for the use of API Compendium factors to estimate emissions from centrifugal compressor wet seal degassing vents.

Response: EPA disagrees with this comment. EPA experience, new data and increased knowledge of industry operations and practices have highlighted the fact that centrifugal wet seal degassing venting emissions estimates based on the factors used in API Compendium are outdated and potentially understated. For a discussion please see the Technical Support Document EPA-HQ-OAR-2009-0923. Further, the API compendium factors do not account for venting emissions from unit isolation valves. EPA determined that direct measurement of centrifugal wet seal degassing venting is required to maintain the necessary quality of data to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-1298-42
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Centrifugal compressor wet seal degassing vents
Section 98.233(o): For the same reasons cited above for reciprocating compressor rod packing venting (excessive cost, well beyond what EPA originally estimated), direct measurement is not appropriate for centrifugal compressor wet seal degassing vents. Therefore, IPAMS requests that the final rule allow for the use of API Compendium factors to estimate emissions from centrifugal compressor wet seal degassing vents.

Response: EPA disagrees with this comment. Please see response to comment EPA-HQ-OAR-2009-0923-1080-24.

Comment Number: EPA-HQ-OAR-2009-0923-1151-124
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(o) Centrifugal compressor wet seal degassing venting.
API requests that EPA broaden the available methodologies for determining flow from centrifugal compressor wet seal degassing vents to include a tracer gas methodology. A description of this methodology and example follow:
1. Introduce an inert tracer gas (such as N2) into the atmospheric degassing tank at a measured (e.g. rotometer) or known (e.g. critical orifice) rate. The rate must be high enough to yield a tracer gas concentration well above the analysis methodology detection limit.
2. Allow sufficient time for the tracer gas to become well mixed in the degassing tank with the gas evolving from the seal oil.
3. Sample the vent stream from the degassing tank and analyze the gas using the appropriate analysis technique (e.g. Gas Chromatography).
4. Calculate the CH_4 and CO_2 content of the vent gas based on the ratio of CO_2 or CH_4 to tracer gas.
5. Multiply this ratio times the tracer gas flow rate to determine the flow rate of CO_2 and CH_4 from the vent. If the vent is routed to a flare or other combustion device, also calculate the flow of all hydrocarbon species in the vent gas analysis which will yield CO_2 when combusted.
6. Use the appropriate techniques in Section 98.233 to convert these flows into GHG terms.

Response: EPA disagrees with this comment. Ensuring a good degree of mixing of the tracer gas with the vented gas to ensure representative sampling for analysis would be of concern. Another potential concern might be of an altering of the solution thermodynamics such that the quantity and quality of the venting gas might be affected by introducing the inert gas. EPA determined that direct measurement of centrifugal wet seal degassing venting is required to maintain the necessary quality of data to inform policy.

Comment Number: EPA-HQ-OAR-2009-0923-1305-55
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.233(o) Centrifugal compressor wet seal degassing venting. BP requests that EPA broaden the available methodologies for determining flow from centrifugal compressor wet seal degassing vents to include a tracer gas methodology. A description of this methodology and example follow:
1. Introduce an inert tracer gas (such as N2) into the atmospheric degassing tank at a measured (e.g. rotometer) or known (e.g. critical orifice) rate. The rate must be high enough to yield a tracer gas concentration well above the analysis methodology detection limit.
2. Allow sufficient time for the tracer gas to become well mixed in the degassing tank with the gas evolving from the seal oil.
3. Sample the vent stream from the degassing tank and analyze the gas using the appropriate analysis technique (e.g. Gas Chromatography).
4. Calculate the methane and CO_2 content of the vent gas based on the ratio of CO_2 or CH_4 to tracer gas.
5. Multiply this ratio times the tracer gas flow rate to determine the flow rate of CO_2 and CH_4 from the vent.
a. If the vent is routed to a flare or other combustion device, also calculate the flow of all hydrocarbon species in the vent gas analysis which will yield CO2 when combusted.
6. Use the appropriate techniques in 98.233 to convert these flows into GHG terms. BP also requests that a single representative volume sample estimate be allowed for same manufactured compressors in the same service and operating parameters. This reduces the data collection burden while gathering adequate data to estimate emissions.
Example:
[Table]

	High Pressure Machine	Low Pressure Machine	Compressed Gas
Nitrogen Purge Rate SCF/Hr	33	25	
Vent Analysis mole%			
CO2	8.741	2.082	11.699
Nitrogen	43.846	86.734	0.6035
Methane	37.872	6.93	80.6955
Ethane	5.98	1.925	5.147
Propane	2.724	1.453	1.556
Butane	0.344	0.368	0.0925
I-Butane	0.19	0.154	0.1525
Pentane	0.044	0.093	0.0175
I-Pentane	0.041	0.072	0.018
Hexane +	0.218	0.189	0.0185
Total Hydrocarbon + CO2	56.1540	13.2660	
Nitrogen Purge Rate (SCF/Hr) X Methane Concentration (mole %) / Nitrogen (tracer) Concentration (mole %) / 60 minutes/hr = Methane flow rate in SCF per minute. Repeat this calculation for CO2 and each of the hydrocarbon species in the vent gas analysis if needed.			
Total Methane Flow SCFM	0.4751	0.0333	
Total Process Gas Flow SCFM	0.7044	0.0637	

Response: EPA disagrees with this comment. Please see response to comment EPA-HQ-OAR-2009-0923-1151-124.

13.2.7.2 RECIPROCATING COMPRESSORS

Comment Number: EPA-HQ-OAR-2009-0923-0055-16
Organization: Indaco Air Quality Services, Inc.
Commenter: Touche Howard

<u>Comment Excerpt Text:</u>
Operational Modes of Compressor Units

Although the mode of a compressor unit can substantially affect the leakage for individual units, the average differences may not be as great as indicated in the EPA source document mentioned in the technical support document for the proposed rule. This Star program “Lessons Learned” publication (EPA, 2004) states that rod packings on idle units may leak at four times the rate of rod packings on running units.

However, the primary references for this document are personal communications and better data is currently available. For instance, the original GRI survey of compressor stations (Indaco, 1995) found a 19% increase in idle versus running rod packings, while in the PRCI study (Howard et al., 1999 – cosponsored by PRCI, GRI, and EPA), idle rod packings were found to leak on average at a 46% greater rate than running rod packings.
A more extensive data set has been compiled by El Paso Natural Gas Company. This data was primarily collected by outside contractors and has approximately ten times as many measurements as the PRCI data set. This data indicates an average of only 6% increase in leakage from idle seals compared to running seals. Consequently, the difference in leakage between running units and idle but pressurized units is probably not as significant as indicated in the EPA Lessons Learned source.

For the depressurized units, the EPA Lessons Learned document suggests an average leak rate of 23.3 scfm. This is in line with the original GRI study of 26.1 scfm. However, the PRCI study indicated a leak rate of 6.78 scfm (although this was based on a smaller data set than GRI it was a more diverse set of stations). Finally, El Paso's data set (which has over four times more data points for unit valves than the GRI study) indicates a leak rate of 9.21+/-2.64scfm.

To estimate the differences between modes, let's assume a model of a reciprocating compressor unit that has one blow down valve, four compressor cylinders and therefore four rod packing seals, and one pair of unit isolation valves. When either running or in standby pressurized mode, there is potential leakage across the blow down valve and through the rod packings. When depressurized, the blow down valve is open and leakage measured from that vent is due to leakage across the unit isolation valves.

Table A-1 summarizes the available emissions factors and the results of the model using the available data.
Table A-1. Emission Factors and Projected Leak Rates from Related Leak Studies Component EPA

Component	EPA (EPA, 2004)	GRI (Indaco, 1995)	PRCI (Howard, 1999)	El Paso (1998 – present)
Rod Packing – Running	0.3	1.02 ± 0.51	1.66 ± 0.48	1.96 ± 0.23
Rod Packing – Idle, Pressurized	1.3	1.21 ± 0.47	2.42 ± 1.05	2.08 ± 0.33
Blow Down Valve	7.5	2.53 ± 1.07	0.39 ± 0.33	2.50 ± 0.72
Unit Isolation Valve Pair	23.3	26.1 ± 9.41	6.78	9.21 ± 2.64
Total Unit Leakage[1]				
Unit Running	8.75	6.61	7.03	10.3
Unit Idle – Pressurized	12.7	7.37	10.1	10.8
Unit Depressurized	23.3	26.1	6.78	9.21
Ratio to Leakage from Running Units				
Unit Running	1.0	1.0	1.0	1.0
Unit Idle – Pressurized	1.43	1.11	1.43	1.05
Unit Depressurized	2.67	3.96	0.96	0.89

[1] Assumes four rod packings, one blow down valve, and one pair of unit isolation valves

Based on these projections, we might expect idle/pressurized units to leak on average between 5% and 43% more than running units. Depressurized units might leak on average slightly less than running units to as much as four times greater.

If the El Paso and PRCI data are representative, then there is little difference between operating modes on average, although for individual units there may be substantial differences. If this is the case, sampling units in an "As Found" mode should provide an excellent representation of total leakage.

If the EPA estimates (or the original GRI factors for unit isolation valves) are more representative, then the depressurized mode may leak on average three to four times greater than the running mode. If this is the case, then it will be important to have a representative sampling of units that spend the majority of their time depressurized.

The three year window recommended under Suggestion 4 in the body of this letter should address this situation. By requiring at least 50% of units to be surveyed in their primary mode over a three year period, units can be surveyed "As Found" annually, which will probably provide a representative sample of each mode. However, the requirement to survey at least 50% of units in their primary mode over a three year period provides a safety net to ensure representative sampling while still allowing the flexibility to avoid disruptions in gas transportation and unnecessary blow downs of units.

Response: EPA agrees that compressor venting be measured in the mode "as found," and has clarified this in today's final rule and allows reporters to schedule the annual measurement of each compressor, and to measure the compressor in the mode as it exists at the time the annual measurement is taken. EPA considered comments received and determined that reporter based emission factors can be developed and applied to the reporter's other compressors that were not measured in that mode. Therefore to lessen undue burden, EPA is requiring the development of reporter based emission factors from these measurements that reporters must apply appropriately to all compressors for the total time each compressor is operated in each mode. However each compressor must be measured at least once every three years in the not operating and depressurized mode without blind flanges in place. Based on comments received compressors come down for maintenance during a three year time period. EPA considered comments received that indicate measuring emissions in the not operating and depressurized mode would be difficult as this mode may not occur frequently. EPA also considered that in the not operating and depressurized mode the potential emissions from the unit isolation valve would be unique to each compressor and the ability of each valve to close completely. Therefore, to lessen burden, reporters are allowed to schedule the measurement of not operating and depressurized mode at any time during those three consecutive years. For more information please see "Compressor Modes and Threshold" memo under rulemaking docket EPA-HQ-OAR-2009-0923. Regarding the comment on studies by GRI (Indaco 1995), PRCI (Howard et al., 1999 by PRCI, GRI, and EPA), and El Paso Natural Gas Company, the supporting data of these studies are not known to be publicly available.

Comment Number: EPA-HQ-OAR-2009-0923-0582-44
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Reciprocating compressor rod packing venting

Calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting as follows:

Step 1: Calculate CH_4 and CO_2 volumetric emissions at ambient conditions as follows:

E [subscript a, i] = MT * T * M [subscript i] (Eq. W- 17)

Where:

E [subscript a, i] = Annual GHG i (either CH_4 or CO_2) volumetric emissions at ambient conditions
MT = meter volumetric reading of gas emissions per unit time, under ambient conditions
T = total time the compressor associated with the venting s operational in the reporting year
M [subscript i] = mole percent of GHG i in the vent gas; use the appropriate gas composition in paragraph (u)(2) of this section

Determination of gas emission rate (MT)

If the rod packing case is connected to an open ended vent line then use one of the following two methods to calculate emissions.

(i) measure emissions a from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in SECTION 98.234 (c).

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

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

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

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

Measurement frequency (MT)

Conduct one measurement for each compressor in each of the operating modes that occurs during a reporting period:

(i) Operating
(ii) standby pressurized
(iii) not operating, depressurized.

Step 2: Calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section

Step3: Estimate CH_4 and CO_2 volumetric emissions and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

WCI Recommendations: WCI recommends adopting the USEPA methodologies for reciprocating and centrifugal compressors with no modifications. Both these methods utilize direct measurement of emissions which will provide accurate, cap-and-trade quality emissions quantification for compressors in gas processing plants.

Response: EPA has reviewed this comment and has retained direct measurement of compressor venting in today's final rule for natural gas processing.

Comment Number: EPA-HQ-OAR-2009-0923-0954-1
Organization: Verdeo Group
Commenter: John Savage

Comment Excerpt Text:
S98.233 (p) Reciprocating compressor rod packing venting

Section (2) stipulates the use of bagging technique or a temporary meter for measurement of emissions "If the rod packing case is connected to an open ended vent line…".

Section (3) stipulates the use of a high volume sampler for measurement of emissions "If the rod packing case is not equipped with a vent line….".

Because high-volume samplers are particularly effective at measuring low volume methane emissions from OELs, Verdeo recommends that such high-volume samplers be included as a measurement option under Section (2).

This would be consistent with best practices as advocated by the EPA's Gas STAR program and would also provide a more convenient and less capital intensive option for many reporting companies.

Response: EPA agrees with the comment to include the option to use a high volume sampler to measure emissions from reciprocating compressor venting, and has revised today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-0959-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
(98.233 (p)) Can we assume that if our reciprocating compressor rod emissions are captured by vapor recovery that they do not have to be calculated or reported.

Response: EPA agrees that if reciprocating compressor venting are captured by vapor recovery or routed to a flare, they do not need to be reported. If the vapor recovery unit is not in operation, companies must follow methodologies for measuring reciprocating and centrifugal compressor emissions. Please see 98.233 (p) of the rule for more information.

Comment Number: EPA-HQ-OAR-2009-0923-1011-15
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233(p) Reciprocating compressor rod packing venting.—(KEY ISSUE) El Paso requests the EPA to allow surveys of compressors to take place in an "as found" mode. While our overall principle recommendation is the same as INGAA's, we have provided options and justified our recommendations based on actual field experience at El Paso sites and review of existing literature on this subject.

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1011-44
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(p) Reciprocating compressor rod packing venting: El Paso recommends monitoring in "As Found" mode. (Note: This section also applies to other vents as well).

Section 98.233(p) requires that all compressor vents be surveyed in each of the operational modes that occur during a reporting period:

1. Operating
2. Standby pressurized

3. Not operating, depressurized

El Paso recognizes and mentioned in its' comments[222] to the EPA proposed reporting rule last year, that the operating mode of compressor units impacts leakage from key compressor components such as rod packing seals, blow down valves, and unit isolation valves. However, a survey of all three modes as required by the EPA in the Subpart W proposal creates enormous challenges and will result in greenhouse gas emissions (GHG) that otherwise, would not have occurred under normal operations.

To alleviate these problems, as the first step, the EPA should take into account that compressor units will primarily fall under one of the following operating scenarios:

	Mode 1	**Mode 2**
Scenario 1	Operating	Standby pressurized
Scenario 2	Operating	Not operating, depressurized

The proposed monitoring requirements do not consider challenges associated with atypical modes of operation. Currently, Subpart W does not take into account that the following modes of operation are considered atypical and probably occur less than 7% of the time (see Appendix I):

1. Scenario 1 - For units that are normally blown down when off line, only a very short amount of time is spent in the "standby, pressurized" mode prior to being blown down ("not operating, depressurized" mode).

2. Scenario 2 - Units that are normally in the "standby, pressurized" mode when off line will only be depressurized for maintenance or during emergency conditions.

Additionally, it does not consider that requiring measurement of both typical and atypical modes of operation would result in unintended GHG emissions from unit blowdowns, disruption of operations and supply, and non-representative conditions. Furthermore, monitoring compressor units in atypical modes has the additional challenge of tracking the operating time in these modes, which is not a common practice by most companies today, and would be a major undertaking not justified by the level of improvement in capturing emissions. The increase in GHG emissions, difficulty in obtaining representative sampling, and supply disruption problems due to the three-mode sampling requirement are important aspects of the problem, which EPA appears not to have considered in proposing the three-mode requirement. EPA should consider the alternatives El Paso suggests below to help alleviate these problems.

To achieve the EPA's goal of collecting meaningful and representative emissions data, the abovementioned operating scenarios should be the focal point of the EPA's monitoring proposal while considering the "as found" mode of operation of a given unit. The "as found" mode of a compressor is the mode in which it is operating on the day of a survey. Although El Paso

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[222] Docket ID No EPA–HQ–OAR–2008–0508.

compressor data shows that the “as found” approach will result in a large sample size of all modes[223] that can be related to the annual emissions from the facility, El Paso recommends a hybrid monitoring approach to ensure an ample data set of all modes over a reasonable amount of time:

1. Each unit located at an applicable facility shall be surveyed once a year in the “as found” mode; and

2. A minimum of 33% of the total population of units that spend more than 10%[224,225,226]. The “not operating, depressurized” mode shall be based on the operation of the unit during the year prior to the 3 year period.

Note that the 3 year time period referenced above will not preclude the submission of emissions data in the “not operating, depressurized” mode during the first reporting year as discussed in the appendix.

Again, it is anticipated that the “as found” approach will result in a large sample size of all modes. However, for any given unit it would be acceptable if it were surveyed in its “as found” mode all three times during the three year period.

In practice, each compressor unit would be surveyed in the mode in which it was found when the survey took place. This data would then be used to calculate emissions factors for each key component category in each mode. Total unit emissions would then be calculated as follows:
1. For the mode in which the unit was surveyed (“as found”), the emissions will be based on actual measurements.

2. For the other mode, the emissions will be based on the number of key components, and emission factors developed for this mode based on company-wide sampling results in this mode.

3. The “atypical” mode will be rolled up with one of the typical modes as described in Equation 4a or 4b in Appendix I.

Details regarding the development of emission factors, including sample calculations, are

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[223] Over the past three years (2007 – 2009), compressor units in the El Paso transmission system spent over 50% of their time in each of the modes as follows: Operating (28.6%), Standby, Pressurized (34.7%), and Not Operating, Depressurized (36.8%). Consequently, “As Found” sampling should provide a representative sample of each mode.

[224] The basis for including only units that are in the "not operating, depressurized" mode over 10% of the time is that emissions from this mode will no longer be dominant at this point. Based on EPA's estimates from the Lessons Learned document in the TSD, the "not operating, depressurized" mode might emit on average 2.7 times more than the "Operating" mode for a unit with four compressor seals. If this is true, for units that are depressurized less than 10% of the time, the depressurized mode contributes less than 25% of the total emissions.

[225] Of their time in “not operating, depressurized” mode, shall be surveyed in that mode once every 3 years.

[226] The three year window is required because it will not be possible to bring many units offline until their normal maintenance cycle arises.

presented in Appendix I. The methodology is illustrated in the table below.

Total population of units located at applicable facilities	1000
Number of units that operated 10% in "not operating, depressurized" mode during the year prior to 3 yr period	400
Min. number of units that must be surveyed in "not operating, depressurized" mode every year, over 3 yr period	133

Lastly, clarification is needed between Section 98.233(p)(2)(i) which requires the measurement of compressor blow down vents along with other compressor unit vents and Section 98.233(q)(3) which indicates that compressor blow down vents should be surveyed using an IR camera and then the “leaker” emission factor applied to calculate leakage.

Response: EPA agrees to allow compressor venting measurement in the ‘as found’ mode. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16. In regard to blowdown venting, the commenter has misinterpreted the proposed rule’s intent. Today’s final rule requires compressor blowdown venting, or through valve leakage, to be reported under Sections 98.233(o) and (p). Today’s final rule also requires equipment leak emissions from compressor blowdown valves to be reported under Section 98.233(q).

Comment Number: EPA-HQ-OAR-2009-0923-1011-56
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Support Documentation for “As Found” Monitoring Proposal

Monitoring Challenges

1. Surveying all three modes will require an additional blow down event per unit, because if a unit is on line it would have to be taken off line and then blown down to survey the depressurized mode. This would result in an additional blowdown event that would increase GHG emissions. On the other hand, if a unit were already blown down, it would have to be pressurized and put on line, and then after the measurements were made, it would be taken back off line and blown down. This would also increase GHG emissions. Hence, the monitoring requirement will result in increased greenhouse gas emissions that otherwise would not have occurred under normal operations as per the case shown below:

At least 50% of compressor units in El Paso’s transmission system are currently depressurized when off line and as a result, already blown down. So all of these units would have to be pressurized and put on line to make a measurement before being put back off line and blow down a second time. All units found operating during the survey would have to be taken off line in order to measure either the “standby pressurized” mode and the “not operating – depressurized” mode.

2. Putting a unit on line temporarily may not provide a representative measurement since the rod packings may not be properly warmed up or it may have to be placed in a re-circulating mode[227] if there is no extra gas capacity in the pipeline.

3. It may not be feasible to take a unit off line due to pipeline demand – requiring a unit to come off line might disrupt gas supply and operations. This may be especially true in the production sector or at transmission stations with only centrifugal units where there may not be any additional units with which to switch.

4. Generally, companies in the oil and gas sector keep track only of the compressor operating hours, so that the only current reliable information is whether a compressor unit is operating or off-line. It is El Paso's understanding that there is no current standardized industry practice or method of determining whether an off-line compressor is pressurized or depressurized. Usually, standard operating procedures are employed to estimate the hours when the unit is off-line. If the standard procedure was to blow down the unit when off- line, then it would be assumed that all off-line hours were spent depressurized. Similarly, if the standard procedure was to leave the unit pressurized when off-line, it would be assumed that all off-line hours were pressurized. Modifying the compressor's Remote Terminal Units (RTU's) for all affected units to track hours in atypical modes would be a major undertaking not justified by the level of improvement in capturing emissions.

5. Units that are usually depressurized when off line might spend a very short amount of time pressurized prior to being blown down, and units that are left pressurized while off line might be depressurized for short periods for maintenance. However, these are atypical conditions. For instance, in 2009, compressor units in El Paso's transmission system that are typically left in "standby pressurized" mode when off-line were "operating" 31.6% of the time, in "standby pressurized mode 61.9% of the time, and "unavailable" 6.5% of the time. This "unavailable" designation comes from El Paso RTU data and the unit may or may not be depressurized during this time, so in the worst case the "not operating – depressurized" mode (the atypical mode for units typically left pressurized when off line) only occurs for 6.5% of the time.

For units which are typically depressurized when off-line, detailed data on the amount of time spent in "standby pressurized" (the atypical condition) is not available. However, in most cases these units are only left in the "standby pressurized" for a short period (less than one hour) prior to being depressurized.

Effect of Operational Mode on Leakage

Although the mode of a compressor unit can substantially affect the leakage for individual units, the average differences may not be as great as indicated in the EPA source document mentioned

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[227] In a recirculating mode, the gas leaving the discharge side of the compressor flows through a bypass valve and into the suction side of the compressor. As a result, suction and discharge pressures are essentially equal in recirculating mode. During typical compressor operations, the difference between suction and discharge pressures are at least 200 psig.

in the technical support document for the proposed rule. This Star program "Lessons Learned" publication (EPA, 2004)[228] states that rod packings on idle units may leak at four times the rate of rod packings on running units.

However, the primary references for this document are personal communications and better data is currently available. For instance, the original GRI survey of compressor stations (Indaco, 1995)[229] found a 19% increase in idle versus running rod packings, while in the PRCI study (Howard et al., 1999 – cosponsored by PRCI, GRI, and EPA), idle rod packings were found to leak on average at a 46% greater rate than running rod packings.

A more extensive data set has been compiled by El Paso. This data was primarily collected by outside contractors and has approximately ten times as many measurements as the PRCI data set. This data indicates an average of only 6% increase in leakage from seals in idle pressurized mode compared to seals in running mode. Consequently, the difference in leakage between running units and idle but pressurized units is probably not as significant as indicated in the EPA Lessons Learned source.

For the depressurized units, the EPA Lessons Learned document suggests an average leak rate of 23.3 scfm. This is in line with the original GRI study of 26.1 scfm. However, the PRCI study indicated a leak rate of 6.78 scfm (although this was based on a smaller data set than GRI it was a more diverse set of stations). Finally, El Paso's data set (which has over four times more data points for unit valves than the GRI study) indicates a leak rate of 9.21 +/- 2.64 scfm.

To estimate the differences between modes, let's assume a model of a reciprocating compressor unit that has one blow down valve, four compressor cylinders and therefore four rod packing seals, and one pair of unit isolation valves. When either running or in standby pressurized mode, there is potential leakage across the blow down valve and through the rod packings. When depressurized, the blow down valve is open and leakage measured from that vent is due to leakage across the unit isolation valves.

Table 1 summarizes the available emissions factors and the results of the model using the available data.

Table 1: Emission Factors and Projected Leak Rates from Related Leak Studies

[228] EPA, 2004. Reducing Emissions when Taking Compressors Off-Line. EPA430-B-04-001, February 2004.

[229] Indaco, 1995. Leak Rate Measurements at US Natural Gas Transmission Compressor Stations. GRI-94/0257.37. Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, IL 60631.

Component	EPA (EPA, 2004)	GRI (Indaco, 1995)	PRCI (Howard, 1999)	El Paso (1998 – present)
Rod Packing – Running	0.3	1.02 ± 0.51	1.66 ± 0.48	1.96 ± 0.23
Rod Packing – Idle, Pressurized	1.3	1.21 ± 0.47	2.42 ± 1.05	2.08 ± 0.33
Blow Down Valve	7.5	2.53 ± 1.07	0.39 ± 0.33	2.50 ± 0.72
Unit Isolation Valve Pair	23.3	26.1 ± 9.41	6.78	9.21 ± 2.64
Total Unit Leakage[1]				
Unit Running	8.75	6.61	7.03	10.3
Unit Idle – Pressurized	12.7	7.37	10.1	10.8
Unit Depressurized	23.3	26.1	6.78	9.21
Ratio to Leakage from Running Units				
Unit Running	1.0	1.0	1.0	1.0
Unit Idle – Pressurized	1.43	1.11	1.43	1.05
Unit Depressurized	2.67	3.96	0.96	0.89

[1] Assumes four rod packings, one blow down valve, and one pair of unit isolation valves

Based on these projections, we might expect idle/pressurized units to leak on average between 5% and 43% more than running units. Depressurized units might leak on average slightly less than running units to as much as four times greater.

The El Paso and PRCI data indicate there is little difference between operating modes on average, although for individual units there may be substantial differences. If this is the case, sampling units in an "As Found" mode should provide an excellent representation of total leakage.

Calculation of System-wide Emissions Using Emission Factors

To aid in understanding the relative contributions of various leak sources to total emissions, a simple model of compressor station fugitive methane emissions can be constructed based on the major sources of leakage. This model is illustrated in Figures 1, 2, and 3.

Figure 1 shows the leak sources for a unit in the "Operating" mode. In this mode leakage may occur through the rod packing seals and across the blow down valve and pressure relief valve, which are closed when the unit is operating. Much smaller leakage may also occur at standard components (such as connectors and valves) on the compressors themselves but this leakage is addressed by Section 98.233(q) of Subpart W. For this case, the total leakage from the key vented components while in the operating mode is calculated per Equation 1:

$$LR_{Operating} = (N_{CS\text{-}Operating} \times EF_{CS\text{--}Operating}) + (N_{BDV} \times EF_{BDV}) + (N_{PRV} \times EF_{PRV}) \quad \text{(Eq. 1)}$$

where:

$LR_{Operating}$	=	Leak rate from a compressor unit in "Operating" mode (scfh CH_4)
$N_{CS\text{-}Operating}$	=	Number of compressor seals on the "Operating" unit
$EF_{CS\text{—}Operating}$	=	Emission factor for compressor seals on "Operating" compressors (scfh CH_4/seal)
N_{BDV}	=	Number of blow down valves on the "Operating" unit
EF_{BDV}	=	Emission factor for blow down valves (scfh CH_4/blow down valve)
N_{PRV}	=	Number of pressure relief valves on the "Operating" unit
EF_{PRV}	=	Emission factor for pressure relief valves (scfh CH_4/pressure relief valve)

For most compressor units, the number of blow down and pressure relief valves will be one of each, but there are some units that have more. Additionally, the emission factors for both blow down valves and pressure relief valves are not expected to differ between units that are in the "Operating" mode and in the "Standby Pressurized" mode, i.e., these factors are not impacted by mode.

Figure 2 shows the leakage for a unit in the "Standby Pressurized" mode. The leakage in this mode occurs at the same sources as in the "Operating" mode except that the leakage through the rod packing seals may differ between the two and consequently is represented by a different emission factor. For this case, the total leakage from the key vented components while in the standby pressurized mode is calculated per Equation 2:

$$LR_{Standby\ Pressurized} = (N_{CS\text{-}Standby\ Pressurized} \times EF_{CS\text{—}Standby\ Pressurized}) + (N_{BDV} \times EF_{BDV}) + (N_{PRV} \times EF_{PRV}) \quad \text{(Eq. 2)}$$

where:

$LR_{Standby\ Pressurized}$	=	Leak rate from a compressor unit in "Standby Pressurized" mode
$N_{CS\text{-}Standby\ Pressurized}$	=	Number of compressor seals on the "Standby Pressurized" unit
$EF_{CS\text{—}Pressurized}$	=	Emission factor for compressor seals on "Standby Pressurized" compressors
N_{BDV}	=	Number of blow down valves on the "Standby Pressurized" unit
EF_{BDV}	=	Emission factor for blow down valves
N_{PRV}	=	Number of pressure relief valves on the "Standby Pressurized" unit
EF_{PRV}	=	Emission factor for pressure relief valves.

Figure 3 represents the leakage from a reciprocating compressor unit that is in the "Not Operating – Depressurized" mode. When a unit is depressurized (blown down), the only source of leakage will be through the unit isolation valves, which are closed in order to isolate the unit from the main pipeline. Leakage through these valves travels through the open blow down valve and is measured at the blow down vent. The leakage in this case is calculated pursuant to Equation 3:

$$LR_{Not\ Operating\text{-- }Depressurized} = N_{Unit\ Isolation\ Valve\ Pairs} \times EF_{Unit\ Isolation\ Valve\ Pairs} \quad \text{(Eq. 3)}$$

where:

$LR_{Not\ Operating\text{-- }Depressurized}$	=	Leak rate from a compressor unit in "Not Operating – Depressurized" mode
$N_{Unit\ Isolation\ Valve\ Pairs}$	=	Number of unit isolation valve pairs
$EF_{Unit\ Isolation\ Valve\ Pairs}$	=	Emission factor for unit isolation valve pairs.

The unit isolation valves are counted as a pair because there will always be at least one suction valve and one discharge valve and measurements at the blow down vent cannot distinguish which valve might be leaking. Typically there will be only one pair per unit at transmission compressor stations; however, storage facilities may have more than one pair per unit.

Annual leakage from a compressor unit can then be calculated using known activity data (amount of time it spends in two of the three modes – "Operating", "Standby Pressurized", "Not Operating—Depressurized") and the leak rate in two of the three modes per Equation 4a or 4b:

$$LR_{Annual} = (\alpha_{\text{Operating}} \times LR_{Operating}) + (\alpha_{\text{Standby Pressurized}} \times LR_{Standby\ Pressurized}). \quad \text{(Eq. 4a) or}$$

$$LR_{Annual} = (\alpha_{\text{Operating}} \times LR_{Operating}) + (\alpha_{\text{Not Operating--Depressurized}} \times LR_{Not\ Operating\text{—}Depressurized}) \quad \text{(Eq. 4b)}$$

where:

LR_{Annual}	=	Annual leak rate from the compressor unit (scf)
$\alpha_{\text{Operating}}$	=	Amount of time compressor unit is "Operating"
$\alpha_{\text{Standby Pressurized}}$	=	Amount of time compressor unit is "Standby Pressurized"
$\alpha_{\text{Not Operating--Depressurized}}$	=	Amount of time compressor unit is "Not Operating—Depressurized".

Figure 1: Leakage from Reciprocating Compressor Unit in "Operating" Mode

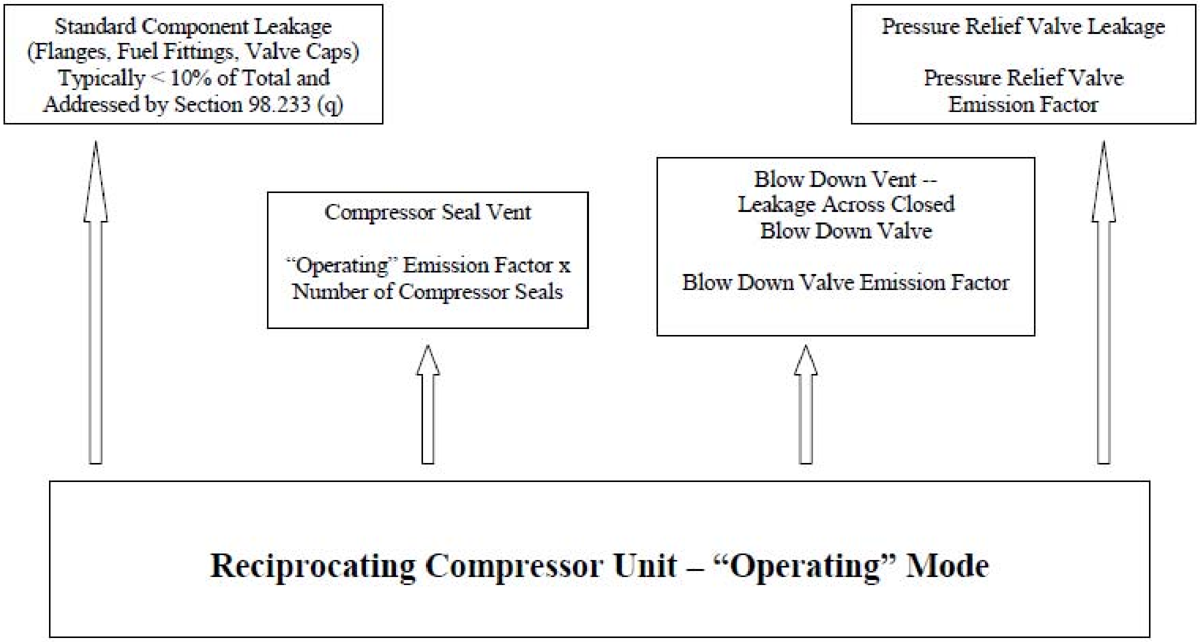

Figure 1: Leakage from Reciprocating Compressor Unit in "Operating" Mode

Figure 2: Leakage from Reciprocating Compressor Units in "Standby Pressurized" Mode

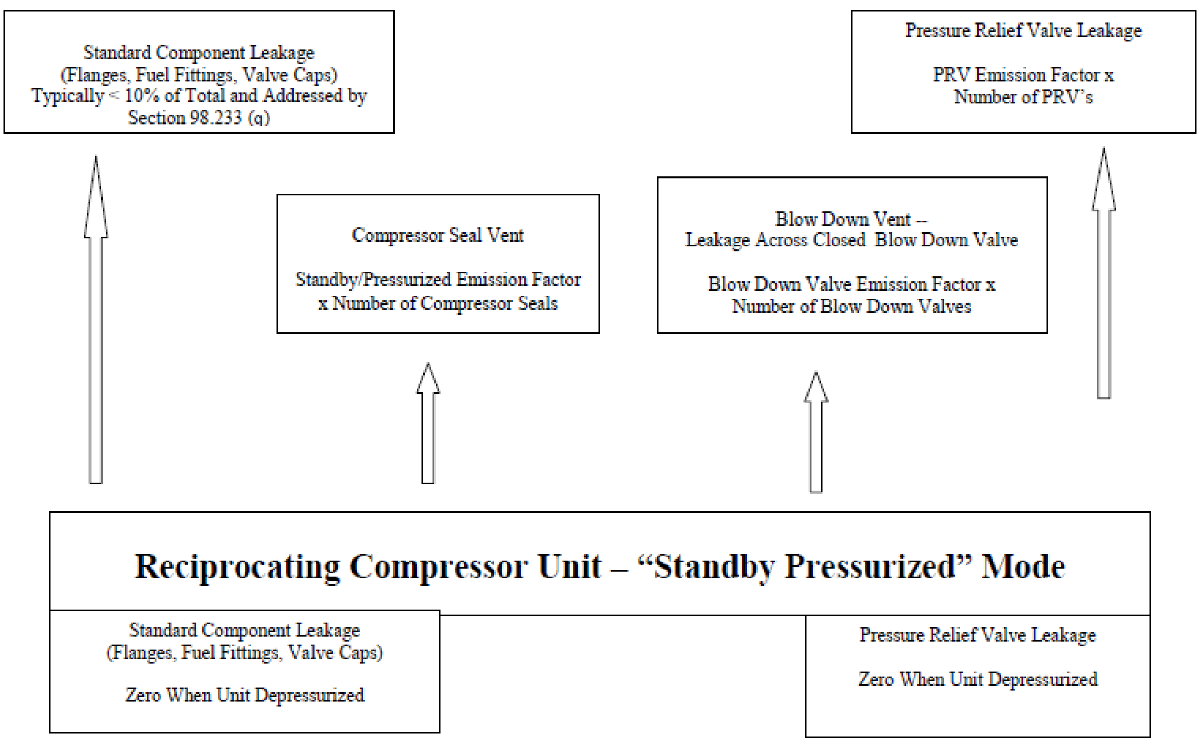

Figure 2: Leakage from Reciprocating Compressor Units in "Standby Pressurized" Mode

Figure 3: Leakage from Reciprocating Compressor Units in "Not Operating--Depressurized" Mode

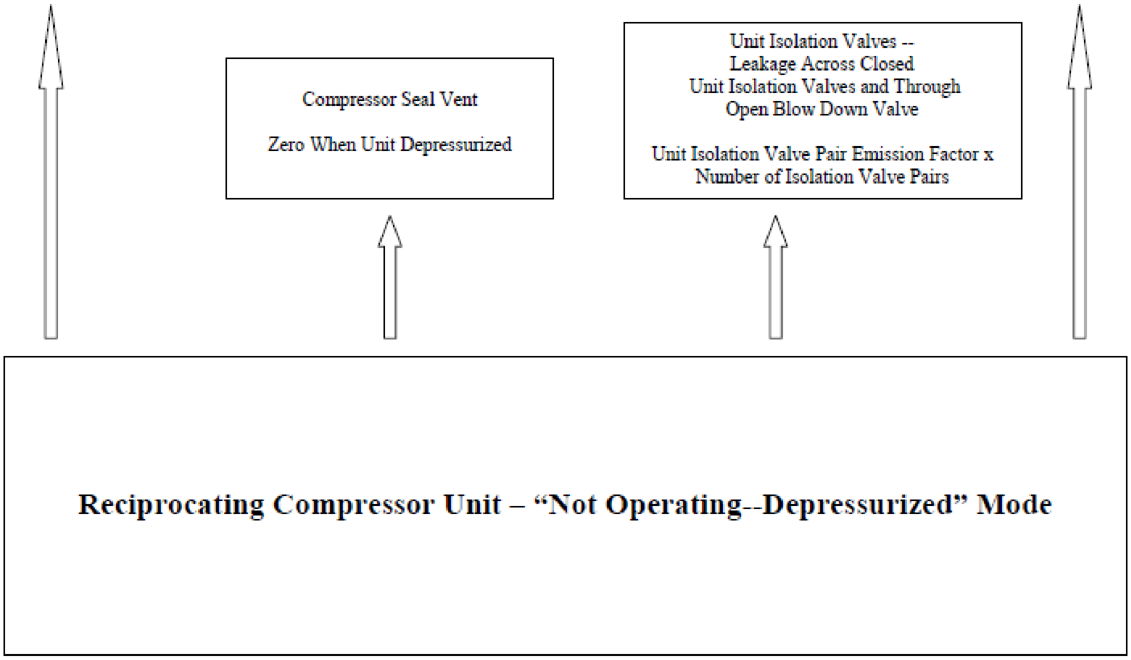

Figure 3: Leakage from Reciprocating Compressor Units in "Not Operating--Depressurized" Mode

Example Calculations of Leak Rates Using Emission Factors

Table 2 presents a sample calculation of the annual leak rate from a reciprocating compressor unit that is left pressurized when taken off line. In this example, hypothetical emission factors are used to represent the key sources. This example also assumes that the compressor unit in question has four compressor rod packing seals, one blow down valve, one pressure relief valve, and one pair of unit isolation valves. Finally, the compressor unit is assumed to be "Operating" 75% of the year (6570 hours) and "Not Operating—Depressurized" the remaining 25% of the year (2190 hours).

Therefore, as shown in Table 2, to calculate the contribution of rod packing seal leakage while the compressor unit is operating, the hypothetical emission factor for "Operating" rod packing seals (99.0 scfh CH_4) is multiplied by the number of rod packing seals (4) and again multiplied by the activity factor (6570 hours per year that the compressor is in "Operating" mode). This result was then divided by 1000 to convert to Mcf/yr (Mcf = 1000 cubic feet in US natural gas industry terminology) resulting in 2602 Mcf CH_4/year. Similar calculations are made for each of the other component categories, with the results from each category being totaled to calculate the overall annual compressor unit leak rate.

Note that in practice, emissions will be calculated by using a combination of unit specific measurement data and operating company emission factors. Actual measurement data will be used for each unit as available, and the emission factors will be used to project leakage from the mode which was not measured. This will make the calculations more facility specific.

Table 3 presents a similar example for a reciprocating unit that is depressurized when off-line.

Table 2: Sample Calculation of Emissions from a Reciprocating Compressor Unit --Pressurized When Not Operating (Basis: 75% Utilization)

Component	Component Emission Factor (scfh CH_4)	No. of Components	Activity Factor (Hours Leaking/Yr)	Annual Emissions (Mcf CH_4/Yr)
Compressor Status: Operating				
Rod Packing Seal – Operating	99.0	4	6570 Hours (Operating)	2602
Blow Down Valve	102.6	1	6570 Hours (Operating)	674
Pressure Relief Valve	10.1	1	6570 Hours (Operating)	66
Compressor Status: Standby Pressurized				
Rod Packing Seal – Standby Pressurized	144.6	4	2190 Hours (Standby Pressurized)	1267
Blow Down Valve	102.6	1	2190 Hours (Standby Pressurized)	225
Pressure Relief Valve	10.1	1	2190 Hours (Standby Pressurized)	22
Total Annual Emissions (Mcf CH_4/year)				**4856**

Table 3: Sample Calculation of Emissions from a Reciprocating Compressor Unit that is Depressurized When Not Operating, (Basis: 75% Utilization)

Component	Component Emission Factor (scfh CH_4)	No. of Components	Activity Factor (Hours Leaking/Yr)	Annual Emissions (Mcf CH_4/Yr)
Compressor Status: Operating				
Rod Packing Seal – Operating	99.0	4	6570 Hours (Operating)	2602
Blow Down Valve	102.6	1	6570 Hours (Operating)	674
Pressure Relief Valve	10.1	1	6570 Hours (Operating)	66
Compressor Status: Not Operating--Depressurized				
Unit Isolation Valve Pair	1344	1	2190 Hours (Depressurized)	2943
Total Annual Emissions (Mcf CH_4/year)				**6286**

Response: EPA does not require the shutdown of compressors to collect data required under subpart W. Please see Section II.F of the preamble to today's final rule. EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1024-25
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

<u>Comment Excerpt Text:</u>

Reciprocating Compressor Rod Packing Venting. Kinder Morgan believes that it is impractical, counterproductive, and unnecessary to require annual emissions measurement for all three operating modes (operating, standby pressurized, and depressurized) of each reciprocating compressor.[230] This requirement will result in increased and unnecessary methane emissions when compressors are removed from service to take measurements in "depressurized" mode, as an additional blowdown will be required that would not have otherwise taken place. Moreover, in order to fulfill this requirement, pipeline owners will likely force the compressor into all three operating modes while the measurement technicians are at the facility. The requirement to measure in all three operating modes will result in unnecessary stress on the equipment. Requiring monitoring at each of the three operating modes would also reduce gas transportation volumes and could result in disruption of service to industrial and residential customers. Although the requirement will result in the collection of more data, there is no reason to believe that EPA would not collect significant quantities of data on compressors in all three operating modes even in the absence of the requirement.

Thus, Kinder Morgan recommends that emissions measurements be taken in whatever mode the reciprocating compressor is in at the time of the measurement, rather than for all three operating modes at each individual compressor. Given the large overall number of compressors that will be monitored under Subpart W throughout the industry, this modification would still provide EPA with abundant data concerning the emissions profile of compressors in each operating mode. At the same time, the modification would minimize operational disruptions at pipelines and avoid the requirement to deliberately cause otherwise unnecessary GHG emitting blowdown events.

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1024-6
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

<u>Comment Excerpt Text:</u>
EPA should not require that reciprocating compressors be monitored in all three operating modes because this is impractical and will result in excess emissions, but should instead require that reciprocating compressors be monitored "as found."

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

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[230] See Proposed 40 C.F.R. SECTION 98.233(p)(4).

Comment Number: EPA-HQ-OAR-2009-0923-1026-12
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
The rule would require that measurements of emission from reciprocating compressor rod packing vents be conducted in three operating modes - operating, not operating/pressurized, and depressurized - but only one of these measurements is ultimately used in the emissions calculation. Taking these measurements will result in an increase in GHG emissions as the units are vented to obtain the measurements. The rule also does not indicate a length of time or operating mode when metering emissions from wet seals. Dominion requests that these measurements be taken in either "typical" operating mode or "as found" mode and that monitoring times be specified.

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1039-14
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

Comment Excerpt Text:
Reciprocating Compressor Rod Packing – Annual Vent Measurements Add Complexity and Increase GHG Emissions. Measurement is Reasonable when Access is Available, but Safety Concerns and Alternatives to Three-Mode Testing Must be Addressed

§98.233(p) identifies requirements for estimating emissions from reciprocating compressor rod-packing vents that include annual "three-mode" testing (i.e., measurements during each operational mode that occurs during a reporting period): operating; standby pressurized; and not operating, depressurized. INGAA is receptive to conducting annual reciprocating compressor rod-packing vent measurements at applicable facilities. However, it is imperative that EPA reconsider mode testing requirements, and thus rule refinements are required. INGAA strongly recommends that annual tests be conducted at a single "as-found" operating mode each year. Vent access safety concerns, manifolded vent lines, and the creation of GHG emissions from unit blowdowns for the sole purpose of depressurized-mode testing present significant obstacles that must be practically resolved.

A. Annual Three-Mode Testing is Complicated and Would Increase GHG Emissions

As required in §98.233(p)(4), three-mode testing introduces significant logistical complexity, burden, cost, and results in unnecessary GHG emissions due to unit blowdowns to complete tests in the "not operating, depressurized" mode. Annual three-mode testing will be difficult, if not impossible, to coordinate with gas control pipeline operations. In addition, testing all modes in a single site visit would be the likely approach. Increases in fuel (to bring on alternative compression) and unnecessary GHG vented emissions from compressor blowdown to address reporting requirements is contrary to overall climate change objectives, and the Final Rule should not introduce such scenarios. Operational changes for the sole purpose of making an emission measurement for the remaining operating modes adds significantly to the burden of this Proposed Rule, and poses significant scheduling issues for initial rule implementation.

"Standby test crews" or other "opportunity" approaches to test a compressor during periods when the operating mode actually occurs are impractical due to logistics, service provider availability, and/or extraordinary inefficiencies and implementation costs. Especially for initial reporting years, multi-mode testing presents significant scheduling and resource issues (e.g., test crew availability). The availability of qualified and experienced test personnel is not expected to be sufficient to meet the demands during the initial years of the Final Rule – and additional demand from multi-mode testing would exacerbate this problem. The expected resource limitations require a practical, phased-in approach or delay for the initial year of measurement (as discussed in Comment XII).

Additional complexities are caused by vent accessibility issues. These include important safety concerns that are discussed in Comment VI. In some cases, multiple compressor vents are manifolded together, and measurement of the common vent line will not provide unit-specific data by mode. However, manifolded vent line measurements can provide a reasonable, accurate alternative for reporting annual vent emissions (see Comment VII).

In addition, "forced-mode" testing may not be indicative of actual emissions. For example, if the common operating mode for a compressor is idle and depressurized, but three-mode annual tests are required, the engine and compressor would likely be started from an idle mode to complete the test. In this case, since the rod packing has not been energized for a considerable time, the short-term emissions measured while test crews are on-site for a "force-mode" test may not be indicative of typical emissions for that mode. Thus, the "characterization" test for the operating mode could misrepresent emissions for that mode.

B. INGAA Recommends a Single Test Each Year in the "As-Found" Mode

In response to issues with three-mode testing, INGAA strongly recommends that annual tests be conducted for a single "as-found" operating mode each year. This approach can be refined based on EPA requirements. For example, the test could be completed in the prevalent operating mode for that engine based on historical utilization records. This could be documented in the annual report under §98.236 and the basis for the prevalent mode determination could be documented in the GHG Monitoring Plan. INGAA recommends rule text revisions to §98.233(p)(4) to include the following:

"(4) Conduct one measurement for each compressor in each of the operational modes that occurs during a reporting period its as-found operational mode. Document which of the three modes was tested:

(i) Operating.;
(ii) Standby pressurized.; or

(iii) Not operating, depressurized."

INGAA understands EPA's interest in mode-based testing is primarily due to vented emissions from leakage through the unit isolation / block valve during the depressurized and standby, pressurized compressor modes, respectively – i.e., natural gas leakage past block valves when the compressor is not operating. Emissions from leakage past pipeline unit isolation / block valves are subsequently vented to atmosphere through the unit blowdown vent (i.e., unit blowdown valve is open to atmosphere). As discussed in Comment V.D, the emission sources and measurement or monitoring requirements related to these vented emissions needs to be clarified, and considerable revisions may be required in the Final Rule to clearly address EPA's intent. If INGAA's proposed alternative to annual three-mode testing is unacceptable to EPA, INGAA requests additional discussion to ensure that a reasonable alternative to the Proposed Rule requirements can be identified.

In employing the INGAA recommended approach, EPA will acquire data over time that provide information on mode-based emissions without creating the significant problems described here. In aggregate, mode-specific data gathered for this segment will facilitate an understanding of mode-based emissions. "As-found" test data would continue to build upon existing mode-specific operating data collected through the voluntary EPA Natural Gas STAR program, as well as other available GHG emissions studies. These data should provide an adequate basis to inform policy decisions.

EPA should also consider that operating time in standby pressurized mode is minimal. For most operators in the gas transmission segment, the standby pressurized mode is a transient or temporary mode, and company procedures typically limit time in this mode. This operating mode exists after engine shutdown for a relatively short period, generally two to four hours, to facilitate a short-duration maintenance activity or other near-term restart of the engine. Once the allotted time period is reached, the pressure is released from the compressors, with the natural gas vented or burned off as fuel. Regardless, cumulative time in this mode is short duration. This action is driven by safety concerns, and the desire to release energy contained within pressurized compressors out of the compressor building. As an example for annual implications, if a company holds compressor pressure for four hours and releases pressure off the compressor 20 times throughout the year, this amounts to 80 annual hours in the standby pressurized mode or less than one percent of the available annual time.

In addition, industry continues to implement programs to improve emission factors and reduce the uncertainty of GHG emission estimates, including recent initiation of a project directed at mode-based emissions. Testing is expected to begin in the summer of 2010 and data from the program, in combination with INGAA member data and the existing knowledge noted above, are expected to result in an improved understanding of mode-specific emissions. Thus, in the interim until all three modes are tested, these data could be used to address data gaps, supplement data collected from reporting, and provide interim access to mode-based data to inform this issue.

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1060-19
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type:
Reciprocating compressor rod packing venting:

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(p)

Monitoring requirements/parameters:

1. Meter volumetric reading of gas emissions per unit time, under ambient conditions.
2. Total time the compressor associated with the venting is operational in the reporting year.
3. Mole percent of GHG i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

Comment:
Compressor engines are generally either operational or not. A compressor would not standby pressurized for any amount of time that would affect its emissions significantly as it would be otherwise offset by the fact that the compressor is not operational. Therefore, requiring measurement in each mode is burdensome and does not reflect a significant source of emissions.

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1061-14
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
Calculation methods for reciprocating compressor rod packing venting should be revised. Section 98.232(d)(l) would require reporting from reciprocating compressor rod packing venting. The calculation method for this source, prescribed at § 98.233(p), has significant problems and should be amended. To begin with, if compressor stations were improperly included as part of the plant itself - a subject addressed above - then the prescribed calculation methods would be extremely onerous. They would require the installation and maintenance of a huge number of individual measuring units because such aggregation would result in so many individual source points.

In addition, the prescribed calculation methods would force operators to conduct one

measurement for each compressor in each of the operational modes that occurs during a reporting period, i.e. operating, standby pressurized, and not operating, depressurized. This would be a counter-productive requirement because not only would it force plants to shut down in order to take such measurements, but it would also create greenhouse gas emissions that would be created through the required depressurization (blowdown).
A preferable alternative to the methods currently set forth in § 98.233(p) would be use of the API Compendium for compressor measurements. The API Compendium would be preferable because the compliance costs associated with the direct measurement requirements for "large" reciprocating compressor rod packing vents are not justifiable given the relatively small emissions that would be measured through use of such methods. Moreover, use of the API Compendium would eliminate the current lack of clarity as to which reciprocating compressor rod packing vents were "large" and which were not. See 75 Fed. Reg. 18620 (Table W-4).

Response: EPA does not require the shutdown of compressors to collect data required under subpart W; please see Section II.F of the preamble to today's final rule. EPA agrees to allow compressor venting measurement in the 'as found' mode with the exception of measuring emissions from compressors in standby, depressurized at least once every three years. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16. In addition, the API compendium factors do not account for emissions from unit isolation valves and therefore would not represent all the emissions required under this rule. The commenter made an incorrect assumption that the rule requires the installation of permanent flow meters on compressor vents. The rule allows for temporary meters such as vane anemometers to measure compressor venting.

Comment Number: EPA-HQ-OAR-2009-0923-1063-1
Organization:
Commenter: Michael Leonard

<u>Comment Excerpt Text:</u>
(98.232 (c)(11)) Reciprocating compressor rod packing venting requires direct measurement from open-ended vent lines when vent lines are present, and Optical Gas Imaging and direct measurement when vent lines are not present. We propose emission factors and component counts be used for emissions from compressor rod packings for onshore petroleum and natural gas production, as this will significantly reduce the burden of leak detection and direct measurement at wellsites and related production facilities.

Response: EPA considered comments received and determined that for onshore production for both reciprocating and centrifugal compressors, that due to the small size of these compressors, that population emission factors can be used, which would result in reduced burden on industry while maintaining the necessary quality of data to inform policy, and today's final rule has been revised accordingly. In today's final rule, onshore production reporters count the number of centrifugal and reciprocating compressors and apply the appropriate emission factor. The other sectors in the rule have compressors larger than those generally found in onshore production, as well as larger emissions (please see the Technical Support Document EPA-HQ-OAR-2009-0923), therefore compressors in other sectors will not be allowed to use emission factors.

Comment Number: EPA-HQ-OAR-2009-0923-1074-37
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(p)(2)(ii):

WBIH requests a clear definition of "all" vents. Does "all" specifically refer to rod packing, blowdown valves, and blowdown vents?

Response: Reciprocating compressors vents include rod packing, unit isolation valves and blowdown vents, and emissions manifolded to common vents.

Comment Number: EPA-HQ-OAR-2009-0923-1074-38
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment on 98.233(p)(4):

WBIH strongly requests measurement of emissions from rod packing, blowdown valves, and blowdown vents be conducted in one mode, the mode existing at the time of the measurement. In order to conduct measurements in the compressor de-pressurized mode, a compressor blowdown would be required, resulting in additional emissions. Additionally, in the compressor de-pressurized mode, the compressor is not available for service creating an interruption of service to customers

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode. Please see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1080-14
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
The section on reciprocating compressor rod packing vents is one of the most burdensome sections of the proposed rule due to the level of effort required to measure relatively small emissions. EPA has greatly underestimated the cost and effort to conduct the direct measurement prescribed for these sources. Aka has hundreds of compressors in operation, each one with multiple compressor rod packings. Additional complexity and cost are presented in the many cases when a single compressor is used for multiple services, for example inlet compression, residue compression and refrigeration compression.

Response: EPA has modified the rule to reduce the burden in gathering data from upstream production compressor sources. Please see response to comment EPA-HQ-OAR-2009-0923-1063-1.

Comment Number: EPA-HQ-OAR-2009-0923-1080-3
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
The direct method of measurement proposed for compressor rod packing vents is not valid in many cases. A direct method will provide a snapshot which is unlikely to be valid as a representative measure for an entire year. Alternative methods, such as documented and controlled studies, would be more valid.

Response: EPA considered alternative methods of monitoring for reciprocating compressors and determined that direct measurement minimized burden on industry while maintaining the necessary quality of data to inform policy. Please see the Technical Support Document (EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1151-125
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(p) Reciprocating compressor rod packing venting.

Onshore Production Source Category: Reciprocating compressor rod packing venting

The rule requires annual observation using an optical leak detection methodology followed by measurement of the leak rate from each compressor seal, in each of three operating modes: (i) operational; (ii) standby pressurized; and (iii) not operating, depressurized.

This approach poses numerous concerns:

- Each compressor will need to be monitored when it is in the various modes during the year in order to arrange for monitoring at the specified conditions. This presents difficulties in scheduling a contractor experienced in the use of the optical leak detection equipment, or requires the operator to have enough of these devices and trained users on hand and in proximity to the compressors when needed (the infrared cameras cost up to $100,000 each to purchase, or about $2,500 per week to rent).

- Alternatively, an operator will need to purposely conduct the compressor shut down, isolation, depressuring, and restart specifically for fulfilling the reporting requirements. Depressuring every compressor each year, in itself, will result in unnecessary greenhouse gas emissions and presents a safety concern for the release of a combustible gas.

- There is an economic concern in shutting down compressors that are necessary for production operations. The rule provides no option for the use of best available monitoring methods if a compressor shut down cannot be scheduled for these measurements.

- Operators will be required to track cumulative time per year for each compressor in the three modes of operation, a significant burden for dispersed equipment. API believes that EPA has significantly underestimated the number of compressors associated with onshore oil and gas production operations by neglecting to account for well-head compressors, resulting in some 33,000 compressors impacted by the rule, and therefore the costs associated with this emission source are significantly underestimated.

- Compressor vent-line access may pose an unnecessary safety risk. In many cases, the design of existing facilities prevents safe access to compressor vents. In addition, accessing vents could place technicians at risk should an emergency shutdown (i.e., blowdown) occur while conducting a vent measurement. While alternative access may be feasible at some facilities, the rule implementation schedule prevents design and installation of vent access points at all facilities within the prescribed timeframe for initial reporting.

As an alternative estimation method for compressor rod packing venting, API proposes that the emission rate determination be conducted as follows for a representative sampling of compressors in their “as-found” mode rather than the 3 operating modes specified above. Over time, data will be gathered for groupings of similar compressors in each of the three specified modes. In aggregate, data from all operators should facilitate an understanding of mode-based emissions.

This representative sample would be comprised of a percentage of the reciprocating compressors for a Sub-basin entity taking into account the safety risk described above. The representative sample would be specifically defined in the GHG Monitoring Plan for a Basin entity and it would be in the range of 1 to 10 percent of the reciprocating compressors for a Sub-basin entity during a year. This representative sample of measured emissions from reciprocating compressor rod packing would then be averaged and applied as the emission factor for all other compressors in the Sub-basin entity.

In general, the representative sample should be evenly distributed based on age of the reciprocating compressors, where the distribution will be determined by the age of a Sub-basin entity’s actual compressor fleet.

Once a Sub-basin entity has performed direct measurement on at least 20 percent of the total number of reciprocating compressors in their “as-found” mode over a period not to exceed 3 years, no further direct measurement will be done and the average of the collected emission data would be used as the emission factor for the Sub-basin entity’s reciprocating compressors from that point forward.

Response: EPA will allow the use of population emission factors for compressors in onshore production. Please see response to comment EPA-HQ-OAR-2009-0923-1063-1.

Comment Number: EPA-HQ-OAR-2009-0923-1151-42
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(p)(2)(ii) Reciprocating compressor rod packing venting. An orifice meter is inappropriate for use in measurements for this scenario due to low accuracy at low flows and pressure, furthermore, the added back-pressure is a safety and reliability concern.

Response: EPA does not require an orifice meter for reciprocating compressor venting measurement, and it would be the responsibility of the reporter to determine the safe operations of their facilities.

Comment Number: EPA-HQ-OAR-2009-0923-1151-82
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(p) Reciprocating compressor rod packing venting. The variable Mi in Equation W-17 should be a volume percent of GHG to make the units work out.

Response: EPA disagrees with this comment to change the variable Mi in this equation to volume percent. Please see the response to comment EPA-HQ-OAR-2009-0923-1151-81.

Comment Number: EPA-HQ-OAR-2009-0923-1151-94
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.232(c)(11) and Section 98.233(p): For reciprocating compressors, the rule requires annual observation using an optical leak detection methodology followed by measurement of the emissions rate from each compressor seal (equivalent to the number of compression cylinders) using a variety of methods. Based on a range of one well-head compressor per 12 gas wells to one well-head compressor per 20 gas wells, a count of compressors associated with oil production from EPA's national inventory, and the assumption that 81% of equipment are covered by the rule, there are between 20,000 and 33,000 well-head compressors subject to the rule. With a range of 2 to 4 cylinders per compressor and the fact that almost all well-head compressors do not have common seal collection piping in place, this yields between 40,000 and 132,000 seals which will require measurement. Additionally, such measurement is required in 3 separate operational modes (operating, stand-by pressurized, and stand-by depressurized)

yielding an estimated range of 122,000 to 396,000 separate required measurements. Assuming that it takes a technician 4 hours to inspect the compressor with an optical device, measure emissions from each seal (most likely using a bagging methodology), shut-down the compressor in a pressurized mode and repeat the measurements, then depressure the machine (which will yield significant emissions) and repeat the measurements, an average of 107,000 hours will be required. At an estimated cost of $150 per hour for a specialty contractor with an optical device and leak measurement equipment and $100 per hour for an operator to accompany the specialty contractor and handle the compressor shut down, isolation, depressuring, and restart, this yields a projected cost ranging from $20 MM to $33 MM. The costs to install seal leak collection systems will far exceed the costs projected above and are not expected to be widely adopted in the short term.

Response: EPA has revised today's final rule and does not require direct measurement of reciprocating compressor venting in onshore production. Please see response to comment EPA-HQ-OAR-2009-0923-1063-1.

Comment Number: EPA-HQ-OAR-2009-0923-1297-4
Organization: Southern Ute Growth Fund
Commenter: Lynn Woomer

<u>Comment Excerpt Text:</u>
Section, §98.233(p) Reciprocating Compressor Rod Packing Vents, proposes direct measurements. In particular, the proposed rule will require measurements of a single compressor in three distinct modes - (1) while operating, (2) while on standby, and (3) when depressurized. This triple measurement scenario on a single unit is neither reasonable, nor justifiable to acquire at most, minimal emissions data. The SUGF suggests EPA reconsider usage of the three measurement scenarios; in particular, eliminate measurement of a depressurized unit. This will lessen the resources needed to acquire data, yet remain consistent with other CAA program (Le. a unit is not required to start up or shut down solely for the purpose of conducting an emissions test).

Response: EPA agrees to allow compressor venting measurement in the 'as found' mode, see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1305-49
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Section 98.233(p) Reciprocating compressor rod packing venting.

The rule requires annual observation using an optical leak detection methodology followed by measurement of the leak rate from each compressor seal, in each of three operating modes: (i) operational; (ii) standby pressurized; and (iii) not operating, depressurized.

This approach poses numerous concerns:

- Either each compressor will need to be monitored for when it is in the various modes during the year in order to arrange for monitoring at the specified conditions. This presents difficulties in scheduling a contractor experienced in the use of the optical leak detection equipment, or requires the operator to have enough of these devices and trained users on hand and in proximity to the compressors when needed (the infrared cameras cost between $80,000 and $100,000 each to purchase, or about $2,500 per week to rent).

- Alternatively, an operator will need to purposely conduct the compressor shut down, isolation, depressuring, and restart specifically for fulfilling the reporting requirements. Depressuring every compressor each year, in itself, will result in unnecessary greenhouse gas emissions and presents a safety concern for the release of a combustible gas.

- There is an economic concern in shutting down compressors that are necessary for production operations. The rule provides no option for the use of best available monitoring methods if a compressor shut down cannot be scheduled for these measurements.

- Operators will also be required to track cumulative time per year for each of the three modes of operation, which is a significant burden for dispersed equipment and not very feasible. BP believes that EPA has significantly underestimated the number of compressors associated with onshore oil and gas production operations by neglecting to account for well-head compressors – which the rule appears to cover. As an alternative estimation method for compressor rod packing venting, BP proposes that emission rate determination be conducted for a representative sampling of compressors in their primary operating mode in the sub-basin entity. Over time, data will be gathered for groupings of similar compressors in each of the three specified modes. In aggregate, data from all operators should facilitate an understanding of mode-based emissions.

BP requests that reporting emissions during normal operation only be required. While the greatest emission rate occurs during pressurized standby operation, the amount of time spent in this operating mode is insignificant, amounting to a small number of hours per year. Our reciprocating compressors are in operation most of the year and if not operating these machines are quickly brought to a depressurized shut down state. Therefore, the only time the machines are in pressurized standby is when the machine is transitioning between normal operation and shut down. As these machines are rarely shut down and this transition period (pressurized standby is brief) accounting for this specific operation mode should not be required. In addition, emissions during depressurized shut down will be negligible as the process gas is not pressurized and does not have proper force/motive to leak process gas through the rod packing; therefore, measuring and reporting emissions during this mode of operation should be excluded from the rule.

Response: EPA will allow the use of population emission factors for compressors in onshore production. Please see response to comment EPA-HQ-OAR-2009-0923-1063-1.

Comment Number: EPA-HQ-OAR-2009-0923-3522-4
Organization: Heath Consultants
Commenter: Milton W. Heath

Comment Excerpt Text:
Compressor Seal Systems (Rod Packings on Reciprocating Engines, Dry/Wet Seals on Turbines)

Compressor seal systems are designed to keep high pressure gas from escaping through a rod into the distance piece (for reciprocating engines). Without going into great detail, these systems are designed to leak a little and over time will have to be replaced because of constant wear on the compressor rod. Because of the nature of these systems, venting gas that does escape through the packing is channeled either directly outside of the building through a separate manifolded rod packing line or directed into the distance piece where typically a larger diameter pipe is manifolded with other compressors to vent this gas out through the roof line in a safe manner.

In order to save valuable time, we recommend that direct measurement with a high volume sampler be performed at each of these vents in order to determine an accurate leak rate. To perform leak screening with a gas imaging camera on these systems is simply a waste of time and adds no value to the process. The same is true with conventional leak detectors as they will typically peg out full scale with the presence of natural gas at each vent.

Safety is still paramount to performing these measurements as it may require the use of Fall Protection and a firmly grounded and well positioned man-lift or ladder. Training in measurement, no matter what method is attempted, should also be given consideration as not all systems are designed the same. With regard to packing systems for reciprocating engines alone, there should be clearly established protocols and standards in place to insure a level of consistency, accuracy and safety is achieved. Again, the safest, most accurate and most reliable method for this leak measurement in our opinion is with the use of a High Volume Sampler.

Response: Please see response to comment EPA-HQ-OAR-2009-0923-0954-1.

13.2.8 OFFSHORE EMISSIONS CALCULATIONS (GOADS SYSTEM)

Comment Number: EMAIL-0010-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923)
Organization: Innovative Environmental Solutions
Commenter: Thomas McGrath

Comment Excerpt Text:
98.232(b) refers to all "stationary fugitive" and "stationary vented" sources as identified in an MMS GOADS study. Please provide specific lists of these sources with descriptions/definitions for Subpart W.

Response: EPA has revised today’s final rule to require reporting of platform equipment leaks, vented, and flare emissions as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platform operators subject to GOADS reporting, shall include those applicable sources which are listed in the GOADS activity data request software, and for which BOEMRE calculated and published GHG emissions. Reporters in state and non-Gulf of Mexico waters will report applicable sources under subpart W using GOADS methodologies. EPA has not provided a list of sources covered by the BOEMRE GOADS study or descriptions and definitions in today's final rule subpart W because the information is incorporated by reference and available publicly through the BOEMRE Gulfwide Emissions Inventory Study.

Comment Number: EMAIL-0010-2 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Innovative Environmental Solutions
Commenter: Thomas McGrath

Comment Excerpt Text:
The MMS GOADS study collects monthly activity data and calculates emissions for the following sources:

Amine units Boilers/heaters/burners Diesel and gasoline engines Drilling rigs Combustion flares Fugitive sources Glycol dehydrators Losses from flashing Mud degassing Natural gas engines Natural gas turbines Pneumatic pumps Pressure/level controllers Storage tanks Cold vents

Emissions are calculated at the platform and unit level (e.g., boiler, engine, etc). For more information on the GOADS study, please see the U.S. Department of the Interior, Minerals Management Service Website:
http://www.gomr.mms.gov/homepg/regulate/environ/airquality/goads -2008.html.

Response: EPA reviewed this comment and has retained GOADS data collection methodologies for offshore platforms.

Comment Number: EPA-HQ-OAR-2009-0923-0847-1
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
The proposed Subpart W is not very clear about the requirements for the offshore petroleum and gas production facilities. The rule should specify whether the facilities for which emissions are calculated under the MMS GOADS (Gulfwide Offshore Activities Data System) program report emissions only for the years for which MMS collects the GOADS activities data from the operators, or whether the offshore facilities perform their own calculations using the GOADS activity data and GOADS emission factors and report their emissions annually to EPA according to 40 CFR 98.2(a) (I). The final rule should clearly state that GOADS is just the software program for collecting activities data for the facility; it does not calculate emissions. The activities data are then fed into a data base system, which contains the emission factors for calculating emissions. The methodologies for calculating emissions are presented in the report

published by MMS that presents a summarization of the emissions.

The draft rule § 98.233 is organized in such a way that it is difficult to discern which requirements are for offshore facilities only, which ones are for onshore facilities only, and which apply to both classes. This needs correction in the final rule.

Response: Under Subpart W, offshore reporters must report every calendar year starting with 2011 using the latest GOADS emissions data (for GOADS reporters); and calculated emissions based on the latest published methodologies (for non-GOADS reporters). However, reporters are required to adjust emissions each year (between GOADS cycles) based on the operating time for the facility relative to operating time in the previous reporting period. The GOADS software, and the Data Base Management System (DBMS), are used by BOEMRE to calculate emissions from GOADS activity data.

Comment Number: EPA-HQ-OAR-2009-0923-0847-3
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Page 18612, 1st column, 1st paragraph: It should be noted that the GOADS software is an activity database system to provide the necessary data to calculate emissions. The software itself does not calculate emissions. The operator of an offshore facility enters information into the GOADS software, which is delivered to MMS. After the information is deemed complete, it is sent to a contractor, where the data are compiled into a data base management system (DBMS), which calculates emissions based on the activity data and emission factors. However, all the formulas for calculation of the emissions are given in the GOADS report. Please clarify in the rule that in order to calculate emissions, the operators would also need to use the GOADS study emission factors. Information about GOADS and the emissions inventories may be found at: http://www.gomr. mms.gov/homepg/regulate/environ/airquality/goads.html .

In the 6th line from the top of the page, it may be more appropriate to state "(e.g., California and Alaska)" rather than "(i.e., California and Alaska)" since EPA would presumably recommend the GOADS reporting method for any possible future facilities in other areas, such as in the Atlantic Ocean.

Response: EPA agrees with these comments. For more information see response to comment EPA-HQ-OAR-2009-0923-0847-1.

Comment Number: EPA-HQ-OAR-2009-0923-0847-9
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Page 18643, § 233(s) (l). MMS GOADS Reporters: It should be clarified again that GOADS is the software for reporting activity data; it does not calculate emissions. Emissions are calculated using the methodologies in the GOADS emission inventory report. There are two "(ii)" under

233(s)(I). The second "(ii)" should be changed to "(iii)" and "(iii)" to "(iv)". For each reporting year that does not overlap with the GOADS reporting year, emissions must be adjusted based on the operating time for each platform. Please clarify how the emissions should be adjusted. Operating time is not the only variable as there are other factors that can change emissions.

Page 18643, 3rd column. last item under § 233(s)(l): The subparagraph states "If MMS discontinues or delays their GOADS survey by more than 4 years, then Platform operators shall collect monthly activity data every 4 years from platform sources . . . ." The GOADS survey is conducted every 3 years. It is not obvious why a time interval of 4 years is chosen. This is inconsistent with § 98.2(a) (I) which requires annual GHG reporting. The same comment applies to § 233(s)(2), Non-MMS GOADS Reporters.

Response: EPA determined to use operating time of the facility as the only variable by which to adjust emissions between GOADS cycles, to reduce burden. Subpart W requires updating the reported emissions each time a new GOADS emissions data and methodologies are published, unless BOEMRE discontinues or delays their GOADS survey by more than 4 years. In that case, offshore reporters are required to calculate emissions according to the latest published GOADS methodologies and emission factors every 4 years, and report those under subpart W for subsequent years, i.e. the reporters will calculate detailed emissions every 4 years, and for the intermediate years the reporters would adjust their platform emissions using an operating factor. EPA determined to use 4 years, as BOEMRE has generally conducted the GOADS survey every 3 years, and therefore today's final rule would not in general supersede the GOADS cycle. For more information see response to comment EPA-HQ-OAR-2009-0923-0847-1.

Comment Number: EPA-HQ-OAR-2009-0923-1027-13
Organization: Offshore Operators Committee
Commenter: Allen Verret

<u>Comment Excerpt Text:</u>
98.235: A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.

OOC Comment: The rule should state that section 98.235 does not apply to offshore platforms. The MMS GOADS process allows for the use of surrogate data in some circumstances when data is not available. Thus, to prevent confusion, the GOADS procedures should be used to handle missing data.

On a general basis, what do you do if missing data comes up in the last 2-3 weeks of December of the previous year, and again in early January of the current year? EPA should remove or reword this sentence.

Response: EPA agrees that those platforms required to report to BOEMRE in a GOADS study should follow those procedures for missing data. However, for platforms that do not report to a BOEMRE GOADS study, it is incumbent on the platform owner/operator to follow the subpart W procedures for estimating missing data outlined in §98.235. Regarding the general comment that certain data is available only in the last weeks of one year and the first weeks of the following year, EPA disagrees that the missing data procedures should be removed. It is incumbent on the owner/operator to make every effort to collect and retain required data. Data available in the last weeks of a reporting year, and then again only in the first weeks of the following year must be collected and retained for each period and each year when the opportunity to collect it arises. Section VI of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), states that merely filling in missing data does not excuse a failure to perform the monitoring or testing. Filling in data gaps that are missing does not relieve an operator from liability for failure to continuously monitor and test as required, as discussed in the response to comment EPA-HQ-OAR-2008-0508-0493.1, excerpt 40.

Comment Number: EPA-HQ-OAR-2009-0923-1027-7
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.232(b): For offshore petroleum and natural gas production, report emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067). Also, additional information on utilizing GOADS in 98.233(s) will be commented on and/or questioned.

OOC Comment: MMS Study 2007-067 does not use the terms "stationary vented" or "stationary fugitives". This leads to confusion about what emission sources from GOADS are included.

Currently, we only provide an equipment inventory, operating times and fuel usage to the MMS, and they run the emissions calculations. We are currently awaiting results from the most recent GOADS study, and the wait could routinely be over the 3 months time we are given to report emissions. For non-MMS GOADS reporters, we will need to obtain the latest MMS GOADS emission factors and methods or find another method for calculating venting and fugitive emissions, as these are not part of the MMS GOADS inventory we provide, nor the final emissions report we receive from the MMS. Is there an agreement between the MMS and EPA on how to manage this interface and any other coordination issues? Is this the latest GOADS study available? If there are other programs in place for GHG emissions calculating and reporting in non-MMS GOADS offshore areas (such as state or voluntary programs), can we have the option to use these instead?

Response: Regarding the terms "stationary vented" or "stationary fugitives, " please see response to comment EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923). Regarding reporters in state and non-Gulf of Mexico waters, please see response to comment EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923). Should the 2011 Gulfwide Emissions Inventory Study not be published in time for reporting year 2011, then for reporting year 2011, offshore reporters subject to GOADS must use the latest (2008) GOADS emissions data. Reporters in state and non-Gulf of Mexico waters (not required to report under GOADS) will report under subpart W for 2011 using the GOADS methodologies published with the 2008 GOADS emissions data. In subsequent years, reporters in state and non-Gulf of Mexico waters will report using the most recent GOADS methodologies published, which historically have been published along with the GOADS emissions data. EPA is not allowing in today's final rule the use of any other methodologies for offshore platform emissions calculation and reporting.

Comment Number: EPA-HQ-OAR-2009-0923-1027-8
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.232(k): You must report under Subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N2O from each stationary fuel combustion unit by following the requirements of Subpart C. Also, 98.2(a)(3)(ii) states that the aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.

OOC Comment:

Since Section 98.232(b) already requires reporting all ''stationary fugitive'' and ''stationary vented'' sources from GOADS, GOADS should be used for reporting combustion emissions, as this information is already collected for GOADS and would eliminate duplicate reporting.

By using GOADS for reporting of combustion emissions, EPA should state that offshore platforms are exempt from reporting under subpart C.

Response: EPA disagrees that GOADS should be used for reporting all combustion emissions. For offshore production, only GOADS flare combustion is reported under subpart W. All other applicable offshore combustion sources must follow the appropriate data collection requirements of subpart C, beginning in 2010. Please see response to comment EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1027-9
Organization: Offshore Operators Committee
Commenter: Allen Verret

<u>Comment Excerpt Text:</u>
Section 98.232(j) and 98.232(k):
(j) You must report the CO_2, CH_4, and N_2O emissions from each flare.

OOC Comment: It is not clear whether this section applies to offshore platforms. If flare sources are to be included, the language should be modified to prevent confusion. Since Section 98.232(b) already requires reporting all ''stationary fugitive'' and ''stationary vented'' sources from GOADS, it would be less confusing to use GOADS for flare emissions, as this information is already collected for GOADS and would eliminate duplicate reporting.

Response: EPA agrees that offshore production must report to subpart W their flare emissions using GOADS. Please see response to comment EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1045-7
Organization: FLIR Systems, Inc.
Commenter: Thomas J. Scanlon

<u>Comment Excerpt Text:</u>
Use of OGI Should be Required at Additional Facilities, Especially Offshore Petroleum and Natural Gas Production Facilities

FLIR Systems believes that the MMS GOADS methodology recommended by the EPA for emissions on offshore oil platforms will inaccurately report emissions from these locations. Turbulent wind conditions make it difficult for operators to properly locate and consistently measure leaks on an oil rig with TVA technology. The video linked above, collected from an oilrig in April of this year, makes this quite clear. In addition, the MMS GOADS recommendation will create safety hazards that will compromise worker safety. The video linked below, taken at the same time, shows a large gas plume wafting through the grating on the same platform.

http://www.flir.com/thermography/americas/us/OGI/offshoreplatforms/

The risks of explosions do exist on oil rigs can be reduced with the proper deployment of OGI. At minimum, annual scans of oil platforms to identify leaks should be required.

Response: The commenter made assumptions which are not consistent with the proposed rule's intent. EPA never intended to specify methodologies for BOEMRE GOADS studies and today's final rule requires reporting GHG emissions based on BOEMRE Air Emissions Inventory Study methods as defined by BOEMRE in their GOADS data system and DBMS emissions calculation and reporting software.

Comment Number: EPA-HQ-OAR-2009-0923-1201-18
Organization: North Slope Burough

Commenter: Edward S. Itta

Comment Excerpt Text:
We do not support the use of the Minerals Management Service (MMS) Gulfwide Offshore Activities Data System (GOADS) air quality data collection system for tracking and reporting GHG emissions from offshore oil and gas sources. Nor do we support expanding the [GOADS] system to platforms in other Federal regions (e.g., in California and Alaska) and all State waters[231].

We consider this to be an inferior standard of measurement for offshore sources.

Response: EPA's decision to adopt BOEMRE GOADS methodology is cost-effective in not requiring duplication of effort, and extension of BOEMRE GOADS methodologies to offshore platforms in state and non-Gulf of Mexico waters provides for more complete coverage and consistent reporting of all offshore operations above the reporting threshold and therefore EPA is retaining GOADS reporting for offshore reporters.

Comment Number: EPA-HQ-OAR-2009-0923-1304-1
Organization: Alaska Oil and Gas Association
Commenter: Marilyn Crockett

Comment Excerpt Text:
Subsection 98.232(b) contains the following requirement: "For offshore petroleum and natural gas production, report emissions from all ''stationary fugitive'' and ''stationary vented'' sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007– 067)."

Companies operating offshore platforms in State waters in Alaska's Cook Inlet have no experience or systems in place to monitor and report emissions under the GOADS system and the proposed rule does not clearly identify sources subject to reporting. Therefore, we recommend that EPA allow the use of best available monitoring methods for the first year of data collection for operations occurring offshore in Cook Inlet.

Response: EPA agrees that use of best available monitoring methods may be necessary for some reporters for the 2011 reporting period so long as the reporters meet the best available monitoring method criteria as described in the rule. Reporters may apply for the use of best available monitoring methods by February 28, 2011 and cite the specific sources and monitoring requirements that cannot be met and justify to EPA's satisfaction why full compliance cannot be met. Please see Section II.F.4 of the preamble to today's final rule, and response to EMAIL-0010-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

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[231] See 75 FR 18611, April 12, 2010.

Comment Number: EPA-HQ-OAR-2009-0923-1305-9
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Offshore Oil and Gas Production Source Category Specific Comments

BP supports EPA's reliance on the Gulfwide Offshore Activity Data System (GOADS) study for emission reporting from the Offshore Petroleum and Natural Gas Production source category. However, as stated in the comments from the Offshore Operators Committee (OOC), there are several areas where additional clarity is needed. BP supports the comments submitted by the OOC.

Response: For further information, please see response to comments EPA-HQ-OAR-2009-0923-1027-7, EPA-HQ-OAR-2009-0923-1027-13, EPA-HQ-OAR-2009-0923-1027-8, and EPA-HQ-OAR-2009-0923-1027-9.

13.2.8.1 FEDERAL WATERS

There are no comments under this category.

13.2.8.2 STATE WATERS

Comment Number: EPA-HQ-OAR-2009-0923-1151-47
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(s) Offshore petroleum and natural gas production facilities in both state and federal water. API supports the use of GOADS data for offshore petroleum and natural gas production facilities. Other programs besides GOADS currently exist under which offshore facilities report emissions, such as state programs. For example, Alabama requires offshore facilities to report emissions. API recommends for non-MMS GOADS reporters, an alternative be added that allows offshore operators to report the information that is submitted to state agencies.

Response: EPA disagrees that facilities in state waters should be allowed to use inventories developed for the state for reporting to this rule. EPA considered allowing alternatives such as state inventories, but decided it was important to receive data collected using consistent methods for this source. Allowing reporters to submit state inventories may result in a loss of data for several activities and additionally will allow for variations in emissions estimates quality because of the different methodologies. Further, having a uniform requirement across the entire industry diffuses potential confusion over the applicability of subpart W and which emission sources are included in the 25,000 tonne CO_2e threshold.

13.2.9 CALCULATION OF VOLUMETRIC AND MASS EMISSIONS

Comment Number: EPA-HQ-OAR-2009-0923-0964-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
98.233 (t) Equations do not currently use (compressibility factor). Should this be incorporated into the equations

Response: EPA disagrees that use of the compressibility factor is necessary to determine emissions of CH_4 and CO_2 from the petroleum and natural gas industry. At most operational conditions expected, these two species will acceptably exhibit near-ideal gas behavior, such that any small error in the calculation will not be expected to substantially impact the results of the emissions calculations. .

Comment Number: EPA-HQ-OAR-2009-0923-1011-49
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.233(u)(2)(iv) GHG Volumetric emissions for underground natural gas storage facilities

The proposed rule requires that GHG volumetric emissions be calculated at standard conditions using the natural gas volumetric emissions at standard conditions (Es,n) and mole percent of GHG in the natural gas (Mi). For underground natural gas storage facilities, Mi shall be the annual average mole percent in the natural gas stored underground. However, "natural gas stored" typically includes base gas and newly injected gas. Gas composition may not be readily available for base gas in older storage facilities and the composition of the injected gas will only be known for each injection cycle. Fugitive emissions for storage stations will occur from sources located between the suction header and storage wells, El Paso recommends the gas that passes through the facility be allowed as the basis of the GHG mole percent for underground natural gas storage facilities.

Response: EPA agrees that GHG volumetric emissions for underground natural gas storage facilities may be based on the mole percent of GHG in the natural gas that passes through the facility. EPA understands that sampling of the natural gas for composition analysis is done at these facilities, and not from the underground well. Additionally, EPA understands that most emissions from this industry segment will occur from the above-ground compression and processing equipment, not the storage wellhead. Thus, today's final rule clarifies that to estimate GHG volumetric emissions for underground natural gas storage facilities, reporters will use the GHG mole percent in natural gas that passes through the facility.

Comment Number: EPA-HQ-OAR-2009-0923-1011-20
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.233(u)(2)(iv) GHG Volumetric emissions for underground natural gas storage facilities.—El Paso requests GHG volumetric emissions for underground natural gas storage facilities be based on mole percent of GHG in the natural gas that passes through facility.

Response: EPA agrees that reporters may use the mole percent of GHG in the natural gas that passes through underground natural gas storage facilities to represent the volumetric emissions from natural gas storage facilities. Please see the response to comment EPA-HQ-OAR-2009-0923-1011-49.

Comment Number: EPA-HQ-OAR-2009-0923-1151-8
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Improve Consistency

API requests that EPA conform the definitions and terminology used throughout the proposed rule to make it more consistent with that used by industry. An example of the use of terms that are not those commonly used by industry or equipment vendors, is the rules use of "high bleed" devices rather than "high bleed" controllers, which is the term recognizable to equipment vendors. API's specific definition recommendations are provided in Section III.1 of this document.

However, even more fundamental than the terminology issues, is the proposed rule's confusing mix of standard conditions for expressing gas volumes and mass. The MRR uses, in different parts of the existing rule (Subparts C, Y, NN, PP) as well as the proposed Subpart W, industry conditions, ambient conditions, actual conditions and STP. API strongly requests that the rule should consistently apply industry standard conditions (60 degrees F and 14.7 psia) since these are the units used in all the referenced industry standards and are the common units used for calibrating industry devices for custody transfer.

In addition, applying the emission equations in the proposed Subpart W produces a mix of emission results. For example, Equation W-1 results in natural gas emissions (scf/yr) from high bleed pneumatic controllers, while Equation W-2 results in annual metric tonnes of CO2 equivalent emissions from low bleed pneumatic controllers. Although, Section 98.233(u) Equation W-22 converts natural gas volumetric emissions to GHG volumetric emissions and Section 98.233(v) Equation W-23 converts GHG volumetric emissions to GHG mass emissions as CO2e, the mix of units resulting for individual source types impedes comparison among sources. For consistency with existing MRR reporting requirements and for comparison among emission source types, all emission equations should result in metric tonnes of GHG emissions by GHG type (e.g., CO_2, CH_4, and N_2O) and then apply Equation A-1 to convert to CO2e emissions.

Consistent use of industry standard conditions for all calculations with conversion of volumes to metric tonnes for each quantified source will ensure that annual GHG emissions are properly quantified and reported.

Response: EPA disagrees that terminology used throughout the rule is not common. The terminology is consistent with partner companies in the Natural Gas STAR Program and other EPA experience and regulations. Subpart W uses the standard conditions of 68 degrees Fahrenheit and 14.7 pounds per square inch absolute as defined in subpart A, and provides calculation methods to convert the reporter's temperature and pressure data to standard conditions. However, EPA disagrees that each equation under subpart W must result in emissions of the same units. The methodologies prescribe that the results of each equation must be converted into standard volumetric emissions and mass emissions using provided conversion equations, and this would ensure reporting on a common basis across sectors in the MRR.

Comment Number: EPA-HQ-OAR-2009-0923-1151-48
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(t)(1) Volumetric emissions. The value of 459.67 should be utilized in place of 460 for equation W-20. However, as stated in earlier comments, API recommends quantifying emissions in subpart W in terms of tonnes to avoid potential errors in converting between volume and mass for gas phase emissions, particularly when the rule applies different sets of standard conditions for gas streams.

Response: EPA disagrees that using the hundredths decimal place in the conversion from degrees Fahrenheit to degrees Rankine is necessary for converting volumetric emissions to standard conditions since this would introduce more than necessary precision and burden (reporting accurately to the hundredths decimal place) and also the resulting difference would be expected to be insignificant. Additionally, EPA disagrees that each equation under subpart W must result in emissions of the same units of tones. Please see the response to EPA-HQ-OAR-2009-0923-1151-8.

Comment Number: EPA-HQ-OAR-2009-0923-1151-50
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.233(u)(i) GHG volumetric emissions. In determining the GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities, the rule states:

“If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in Section 98.234(b).” This appears to require quarterly sampling and analysis for each well. If measurement is required at each well - there are approximately 667,000 wells impacted by the rule × 4 samples/year × $200 each (which is on the low side). This equates to $534 MM per year just for the sampling, or about 20 times the total first year cost in the EIA.

In order to reduce the cost burden, API recommends that the final rule should explicitly state that the composition data/GHG mole percent can be obtained from representative annual samples of produced natural gas within the Sub-basin. Consistent with API’s proposed Sub-basin entity approach, the representativeness of the samples can be based on grouping of fields (in EIA’s field list) within a Basin entity based on common production characteristics. These characteristics would be the same (or groups of similar) producing reservoirs, similar well depths and well-bore configurations, similar pressure and temperature ranges, similar fluid compositions and GOR’s, similar production arrangements and surface equipment, and similar operational characteristics and practices. The Basin entity should discuss the produced natural gas sampling strategy in the monitoring plan.

Response: EPA agrees that reporters may use representative samples of field gas composition and that quarterly sampling of produced gas composition is not necessary. Today’s final rule clarifies that annual sampling of produced natural gas for composition analysis is allowed or that reporters may use the most recent representative sample analysis of the field that is already available for the purposes of subpart W. Please see Section II.E of the preamble to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1305-26
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Section 98.233(u)(i) GHG volumetric emissions.

In determining the GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities, the rule states: “If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in Section 98.234(b).” It is not clear if sampling must be conducted quarterly at each well or if quarterly samples need to be taken at the basin level which implies just 4 samples per operator per basin annually. If sampling and analysis is required at each well the sampling burden is unreasonable and not necessary.

In order to reduce the cost burden, BP recommends that the final rule should explicitly state that the composition data/GHG mole percent can be obtained from representative annual samples of produced natural gas within the sub-basin. Consistent with API’s proposed sub-basin approach the representativeness of the samples can be based on grouping of fields (in EIA’s field list) within a basin based on common production characteristics. As the source categories included in Subpart W all produce/process fluids from fluid reservoirs, fluid properties will be consistent throughout the year for each field and there will be insignificant variance amongst quarterly samples. This contrasts refinery operation which may receive different crude feed streams and where there may be a variance in composition analysis between quarters. Reducing the sampling requirement from quarterly and individual locations to annual and representative samples will provide equal quality information to meet EPA's intent while reducing the burden to gather this information. The reporting entity should discuss the produced natural gas sampling strategy in the monitoring plan.

Response: EPA agrees that requiring quarterly sampling of produced gas from each well in a basin for composition analysis is not necessary; please see the response to EPA-HQ-OAR-2009-0923-1151-50.

Comment Number: EPA-HQ-OAR-2009-0923-1151-83
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(u) GHG volumetric emissions. The variable Mi in Equation W-22 should be a volume percent of GHG to make the units work out.

Response: In today's final rule, EPA more correctly expresses this term in mole fraction, which is close enough to volume fraction so as to be considered synonymous assuming near-ideal gas behavior; please see the response to EPA-HQ-OAR-2009-0923-1151-81.

Comment Number: EPA-HQ-OAR-2009-0923-1298-45
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
GHG volumetric emissions

Section 98.233(u): GHG volumetric emissions generally would require the use of continuous gas analyzer or quarterly gas analyses for facilities operated by IPAMS' member companies. There is no justification for such frequent gas analyses. Therefore, IPAMS requests that a one-time analysis at the field level be used for this calculation.

Response: EPA disagrees that a one-time composition analysis at the field level will be sufficient to characterize the composition of produced natural gas for that field indefinitely. While EPA agrees that quarterly sampling is not necessary, studies have shown that over years composition of aging wells and fields change. Thus, today's final rule stipulates that the composition of produced natural gas for each field can be based on the most recent available sample analyses; Please see the response to EPA-HQ-OAR-2009-0923-1151-50. For more information, please see Section II.E of the preamble to today's final rule.

13.2.10 EOR INJECTION PUMP BLOWDOWN

Comment Number: EPA-HQ-OAR-2009-0923-0582-39
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
EOR Injection Pump Blowdown

Source Description: EOR operations where CO2 is injected into a formation to increase production use pumps to inject CO2. These pumps are periodically blowndown to perform maintenance and repair activities. The following method has been proposed for the calculation of these emissions.

Measurement Options: The approach recommended by USEPA was considered to be implementable without undue burden and sufficiently accurate to support a cap and trade rule. No other options were evaluated by WCI.

USEPA Subpart W Approach:

Step 1: For each pump calculate the total blowdown volume in cubic feet (including, but not limited to, pipelines, compressors and vessels) between isolation valves.

Step 2: Retain logs of the number of blowdowns annually.

Step 3: Calculate emissions using Equation W-24

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$

Where:

$Mass_{c,I}$ = annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns

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

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

R_c = density of critical phase EOR injection gas in kg/ft^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.

GHG_i = mass fraction of GHG_i in critical phase injection gas.

Mass [subscript c, i] = N * V [subscript v] * R [subscript c] * GHG [subscript i] * 10^-3

Where:

Mass [subscript c, i] = annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns
N = number of blowdowns for the equipment in the reporting year.
V [subscript v] = total volume in cubic feet of blowdown equipment chambers (including, but not limited to, pipelines, compressors, manifolds and vessels) between isolation valves
R [subscript c] = density of critical phase EOR injection gas in kg/ft^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.
GHG [subscript i] = mass fraction of GHG [subscript i] in critical phase injection gas.

WCI Recommendation: We recommend using the approach provided by USEPA without any modification.

Response: EPA agrees with the comment and in today's final rule, EPA has retained the equations to calculate EOR injection pump blowdown emissions as in the supplementary rule proposal.

Organization: Commenter:
Comment Number: EPA-HQ-OAR-2009-0923-1151-52
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(w) EOR injection pump blowdown. Because carbon dioxide is the only compound used for EOR that exists in a supercritical state, API believes this requirement should be refocused. Further, the physical properties of carbon dioxide, while in the supercritical state, are very difficult to determine outside of controlled laboratory conditions. API recommends the following changes:

Section 98.233 (w) EOR injection pump blowdown.

Estimate carbon dioxide pump blowdown emissions as follows:

(1) Estimate the total volume in cubic feet (including, but not limited to, pipelines, compressors and vessels) between isolation valves.
(2) Retain logs of the number of blowdowns per reporting period.
(3) Use Equation W-24 of this section to estimate the total annual venting emissions:

$Mass_{CO2} = N * V_v * R * 10^{-3}$ (Eq. W-24)

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions from blowdowns.
N = Number of blowdowns for the equipment in reporting year.
V_v = Total estimated volume in cubic feet of blowdown equipment chambers (including, but not limited to, pipelines, compressors, manifolds and vessels) between isolation valves.
R = Estimated density of critical phase carbon dioxide EOR injection gas in kg/ft^3. Retain records of carbon dioxide density value.

Mass [subscript CO2] = N * V [subscript v] * R * 10^-3 (Eq. W-24)

Where:

Mass [subscript CO2] = Annual EOR injection gas venting emissions in metric tons at critical conditions from blowdowns.
N = Number of blowdowns for the equipment in reporting year.
V [subscript v] = Total estimated volume in cubic feet of blowdown equipment chambers (including, but not limited to, pipelines, compressors, manifolds and vessels) between isolation valves.
R = Estimated density of critical phase carbon dioxide EOR injection gas in kg/ft^3. Retain records of carbon dioxide density value.

Response: EPA disagrees with the commenter. The commenter has suggested the removal of the GHG fraction in the CO_2 stream being used for EOR. EPA agrees that the CO_2 coming into the EOR operations from a pipeline is typically almost all CO_2. However, often, EOR operations recycle the CO_2 stream produced from the EOR operations back into the CO_2 injection wells without the separation of produced hydrocarbons. Hence, the CO_2 stream at different points in the EOR system will have differing levels of CO_2 and EPA intends to gather that information. Also, EPA has reduced the sampling burden from quarterly to annual and allows the use of industry standard practices to determine density of super critical CO_2. EPA, has therefore, retained the GHG fraction calculation in today's final rule.

13.2.11 DISSOLVED CO_2 CALCULATIONS

Comment Number: EPA-HQ-OAR-2009-0923-0962-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

Comment Excerpt Text:
98.233 (x) (y) These sections require quarterly samples be taken to determine dissolved CO2 in produced fluids. Is there any provision to allow engineering estimates or less frequent testing (if consistent values are obtained)

Response: In regards to the quarterly sampling of hydrocarbon liquids at EOR facilities, please see response to EPA-HQ-OAR-2009-0923-0582-40 for further details.

In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1040-21
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
98.233(x)-(y):
Hydrocarbon liquids dissolved CO2 and produced water dissolved CO2: The vast majority of non-Enhanced Oil Recovery ("EOR") production fields do not have enough CO2 in their hydrocarbon liquids and produced water to have more than a de minimis environmental impact. We request that EPA state that this section applies only to hydrocarbon liquids and produced water in CO2 injection EOR production fields.

Response: Today's final rule provides the necessary clarification to limit sampling of hydrocarbon liquids to CO_2 EOR facilities only. With regard to the sampling of hydrocarbon liquids at CO_2 EOR facilities, please see the responses to EPA-HQ-OAR-2009-0923-0582-40 and EPA-HQ-OAR-2009-0923-1011-21.

Today's final rule does not require the monitoring of CO2 from produced water at any onshore petroleum and natural gas production operations. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1170-11
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:

In addition, 98.233(x) and (y) require quarterly samples at each hydrocarbon and produced water tank to determine the concentration of dissolved CO_2. With an average of 4 tanks/battery (2 hydrocarbon and 2 produced water) this cost would have a significant financial impact and would be unnecessary. The same reputable laboratory referenced above has quoted approximately $400 to analyze the CO_2 in produced water and $700 to determine CO_2 in hydrocarbon liquids; and again, this is the cost for the laboratory analysis/sample ONLY, not the time, labor or equipment to take the samples. Also, as stated above, the composition of the gas would not vary significantly from battery to battery so quarterly sampling would be redundant. The cost for the laboratory analysis alone to determine the CO_2 retained in the hydrocarbon and produced water tanks in Pioneer's Permian Basin operations only would be approximately $15.8 million. This will add millions of dollars for compliance, clearly not taken into account in EPA's cost impact analysis. Further, these two provisions are nonsensical and the data would be meaningless. Any CO_2 or gaseous compounds would have been processed and contained prior to reaching the storage tanks. Further, as the contents of the tanks are no longer under pressure, any remaining CO_2 would dissipate immediately so the samples taken at some point afterwards would not be valid . Any amount left in tank would be negligible.

Pioneer requests that 98.233(x) and (y) be deleted from the Subpart. If these sections remain in the final rule, Pioneer requests that an annual representative sample be taken from one oil and one produced water tank in each basin, or alternatively in the reporting unit (per {(reporting unit" recommendation in point 1). Further, section (y) states that sampling is not necessary if EOR operations route produced water from separation directly to re-injection. As a second alternative, if (y) remains in the final rule, Pioneer requests that produced water which is routed directly from the tank to a salt water injection or disposal well be exempt as well. Lastly, another potential approach is every time a well is completed, oil, water and gas samples could be taken at that time and this data provided to the EPA. This would be an on-going obligation and not limited to the annual compliance time periods.

Response: EPA agrees with the comment on sampling of hydrocarbon liquids. With regard to the annual sampling of hydrocarbon liquids, please see the responses to EPA-HQ-OAR-2009-0923-0582-40, and EPA-HQ-OAR-2009-0923-1011-21.

Today’s final rule does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129. These changes to today’s final rule will mitigate any cost concerns on the reporting of emissions from EOR facilities.

Comment Number: EPA-HQ-OAR-2009-0923-1174-9
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text:
Hydrocarbon Liquids Dissolved CO2 & Produced Water Dissolved CO2 (§ 98.233(x)-(y))

The proposed rule requires quarterly samples from each affected production site to determine the amount of CO_2 retained in hydrocarbon liquids after flashing as well as in produced water at atmospheric pressure.

We believe this requirement will not provide any valuable information because the CO_2 that would be measured is the amount of residual CO_2 that is entrained in produced water or hydrocarbon liquids and is not emitted to the atmosphere.

The quarterly sampling alone of these two fluid streams at each production site represents approximately 60% of Devon's costs.

Therefore, EPA should remove this requirement from the reporting rule.

Response: EPA agrees with the comment on sampling of hydrocarbon liquids. With regard to the annual sampling of hydrocarbon liquids, please see the response to EPA-HQ-OAR-2009-0923-0582-40, EPA-HQ-OAR-2009-0923-1011-21, and EPA-HQ-OAR-2009-0923-1151-128.

Today's final rule does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1298-46
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Hydrocarbon liquids dissolved CO_2 & Produced water dissolved CO_2

Section 98.233(x) & (y): The vast majority of non-Enhanced Oil Recovery ("EOR") production fields do not have enough CO_2 in their hydrocarbon liquids and produced water to have more than a de minimis environmental impact. In addition, based on the placement of these sections in the rule, it appears that EPA intended that Section 98.233(x) and (y) apply only to EOR. IPAMS requests that EPA state explicitly that these sections apply only to hydrocarbon liquids and produced water in EOR production fields.

Response: Today's final rule provides the necessary clarification to limit sampling of hydrocarbon liquids to CO_2 EOR facilities only. With regard to the sampling of hydrocarbon liquids at CO_2 EOR facilities, please see the responses to EPA-HQ-OAR-2009-0923-0582-40 and EPA-HQ-OAR-2009-0923-1011-21.

Today's final rule does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. With regard to sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

13.2.11.1 HYDROCARBON LIQUIDS

Comment Number: EPA-HQ-OAR-2009-0923-2003-2
Organization:
Commenter: S. Lampa

In addition, with regard to the gas industry, I am concerned about the impact that fracking will have on my community's drinking water. From what I understand, in a worst case scenario, the petroleum distillates used in a single well could contain enough benzene to contaminate more than 100 billion gallons of drinking water to unsafe levels, according to drilling company disclosures in New York State and published studies. (NYDEC DSGEIS 2009, Pagnotto 1961) That is more than 10 times as much water as the state of New York uses in a single day. (NYDECDSGEIS 2009)Fracking has already been linked to drinking water contamination and property damage in Colorado, Ohio, Pennsylvania, Wyoming and other states. (Lustgarten 2008a, 2008b).Clearly, more transparency is needed by the drilling companies. It is important that the Environmental Protection Agency use its existing authority to determine whether companies are using diesel and enforce permit requirements.

Response: EPA has reviewed the commenter's remarks. However, determining whether companies are using diesel and enforcing permit requirements is beyond the scope of this rule.

Comment Number: EPA-HQ-OAR-2009-0923-0582-40
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
6. Hydrocarbon Liquids Dissolved CO2

Source Description: Enhanced Oil Recovery operations that use injection of CO2 produce petroleum that has significant amount of dissolved CO2. Although this CO2 is usually separated from the petroleum product and re-injected, the liquid portion of petroleum still contains dissolved CO2 which is released in a storage tank as the CO2 flashes out of the liquid hydrocarbons. Losses will continue during transportation and processing stages.

Measurement Options: The approach recommended by USEPA was considered to be implementable without undue burden and sufficiently accurate to support a cap and trade rule. No other options were evaluated by WCI.

USEPA Approach: The re-proposed subpart W contains the following method for the determination of CO2 emissions.

Step 1: Determine the amount of CO2 retained in hydrocarbon liquids after flashing in tankage at standard conditions. Quarterly samples must be taken according to methods set forth in SECTION 98.234(b) to determine retention of Co2 in the hydrocarbon liquids immediately downstream of the storage tank.

Step 2: Estimate emissions using Equation W-25 of this section.

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

Where:

$Mass_{s,CO2}$ = annual CO_2 emissions from CO_2 retained in hydrocarbon liquids beyond tankage, in metric tons

S_{hl} = amount of CO2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions

V_{hl} = total volume of hydrocarbon liquids produced in barrels in the reporting year

Mass [subscript s, CO2] = S [subscript hl] * V [subscript hl] (Eq W-25)

Where:

Mass [subscript s, CO2] = annual CO2 emissions from CO2 retained in hydrocarbon liquids beyond tankage, in metric tons
S [subscript hl] = amount of CO2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions
V [subscript hl] = total volume of hydrocarbon liquids produced in barrels in the reporting year

WCI Recommendation: We recommend using the approach provided by USEPA without any modification.

Response: EPA disagrees that EPA should use the same approach without an modification. In today's final rule EPA has made some modification to the applicability and monitoring methods for this source. Please see responses to EPA-HQ-OAR-2009-0923-1011-21 and EPA-HQ-OAR-2009-0923-1058-13 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1011-21
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
XXI. Proposed Rule Section 98.233(x) Hydrocarbon liquids dissolved CO2. —El Paso urges EPA to limit the applicability of the requirements for dissolved CO2 specifically to onshore oil and gas operations that utilize high CO2 content streams for enhanced oil production.

Response: In the April 2010 proposed rule found in docket (EPA-HQ-OAR-2009-0923-0002), EPA did not intend to require sampling of hydrocarbon liquids at facilities other than at EOR facilities. Today's final rule provides the necessary clarification to limit sampling of hydrocarbon liquids at CO_2 EOR facilities only.

Comment Number: EPA-HQ-OAR-2009-0923-1011-50
Organization: El Paso Corporation

Commenter: Fiji George

Comment Excerpt Text:
XXI. Section 98.233(x) Hydrocarbon liquids dissolved CO2

The proposed rule requires determining the amount of CO2 retained in hydrocarbon liquids and produced water after flashing in tanks. The rule requires collecting these samples once each quarter for every produced water or hydrocarbon tank.

This source has the highest cost per metric tons of emissions based on El Paso's cost estimates. El Paso urges EPA to limit the applicability of the requirements for dissolved CO2 specifically to onshore oil and gas operations that utilize high CO2 content streams for enhanced oil production. This is the only operation for which this emission source makes sense and this is clearly the intent for this emission sources as discussed in the TSD. The rule language should make this distinction and only be applicable to EOR operations.

Response: EPA agrees with the comment. With regard to the sampling of hydrocarbon liquids at CO_2 EOR facilities, please see the response to EPA-HQ-OAR-2009-0923-1011-21.

Comment Number: EPA-HQ-OAR-2009-0923-1042-24
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
§98.233(x) Hydrocarbon liquids dissolved CO2

ConocoPhillips Comment:

a.) We request EPA clarify that this paragraph applies only to hydrocarbon liquids production associated with CO2 EOR operations. On page 52 of the TSD, EPA states "Onshore petroleum production that uses EOR with CO2 injection results in the production of petroleum with significant amounts of CO2 dissolved in it." Limiting this paragraph to only hydrocarbon liquids production associated with CO2 EOR operations, as it appears to be EPA's intent, will significantly reduce the resource and analytical burden.

b.) This paragraph requires the quarterly sampling of liquid downstream from the tank for dissolved carbon dioxide. In the case of the North Slope facilities, this will prove to be a burdensome exercise without any benefit. Only a very small fraction of the oil produced by our North Slope facilities is routed to storage tanks. This is done only to divert oil for non-routine process reasons or because the oil is off-specification (slop oil) and the amount so routed is well under 10%. Indeed, E&P Tanks will quantify under 98.233(j) any CO2 liberated from these tanks. We thus request that this requirement not apply to our North Slope facilities.

Response: EPA agrees with the comment about hydrocarbon liquids at CO_2 EOR facilities; Please see the response to EPA-HQ-OAR-2009-0923-1011-21 for further details. If the North

Slope facilities do not have CO_2 EOR facilities, then the section of sampling of hydrocarbon liquids does not apply to them.

Comment Number: EPA-HQ-OAR-2009-0923-1058-13
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
Paragraphs (x)(1) and (y)(1), referring to hydrocarbon liquids and produced water dissolved in CO2 requires quarterly sampling to determine retention of CO2 in each produced fluid. As stated earlier, the composition of these streams does not fluctuate frequently enough to warrant quarterly sampling. We propose every other year or annual sampling to satisfy the CO2 retained in each fluid in equations W-25 and W-26.

Response: EPA agrees with the comment about annual sampling of hydrocarbon liquids. EPA has determined that the quarterly sampling of hydrocarbon liquids at EOR facilities is unduly burdensome without providing any substantial improvement in data quality. Hence, in today's final rule EPA requires annual sampling of hydrocarbon liquids at CO_2 EOR facilities.
In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1060-23
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
Source Type
Hydrocarbon liquids dissolved CO2

Regulatory reference for calculation/ monitoring requirements
40 CFR 98.233(x)

Monitoring requirements/parameters:
1. Amount of CO2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.
2. Total volume of hydrocarbon liquids produced in barrels in the reporting year.

Comment:
It seems the EPA is assuming that the entrained CO2 will eventually be released, but it is unclear why this assumption is being made. Further, it seems that the level of effort is not commensurate with the amount of CO2 even the EPA expects to be emitted from this source. Also, this source is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs.

Response: EPA wants to determine the amount of CO_2 entrained in hydrocarbon liquids leaving an EOR facility. Please see the response to EPA-HQ-OAR-2009-0923-1011-21. This is required to determine the net balance of CO_2 in an EOR system nationwide. Whereas EPA has tried to adapt and conform with other programs, today's final rule is tailored to gather sufficient and relevant data to inform future policy and therefore EPA has determined that this data is necessary in order to do so.

Comment Number: EPA-HQ-OAR-2009-0923-1074-39
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.233(x)(1):

Regarding the requirement for quarterly sampling, WBIH requests a one-time sample requirement. A sample is taken when the well begins production and that analysis will be used to calculate emissions using direct measurement or E&P Tanks as outlined in previous comments for 98.2330) and in the general comments (75 FR 18612). Quarterly sampling is not required for current air quality compliance conditions and would be extremely burdensome and costly, which EPA has likely significantly underestimated the cost involved with quarterly sampling

Response: EPA has determined that annual sampling of hydrocarbon liquids from EOR facilities is sufficient for the level of data quality being sought. Please see the response to EPA-HQ-OAR-2009-0923-1058-13. However, a one-time sample is not deemed sufficient. The level of CO_2 in the reservoir and dissolved in the produced hydrocarbons varies significantly over the entire EOR cycle. Hence it is important to monitor CO_2 levels on an annual basis. Also, EOR operations are not as extensive as conventional production operations and EPA expects this reporting burden to be reasonable.

Comment Number: EPA-HQ-OAR-2009-0923-1151-128
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
P. Section 98.233(x) Hydrocarbon liquids dissolved CO2

In the Technical Support Document (TSD), dissolved CO2 in hydrocarbon liquids is discussed in relation to CO2 EOR operations. However, the proposed rule applies the category to all onshore production. If EPA does retain this source category in the final rule, it should be restricted to just CO2 EOR operations.

API believes the potential GHG emissions captured from this source category do not justify the estimated costs of some $225.8 million per year. Based on a process simulation conducted by one API member company, using an average of 4 condensate streams that had CO2 analyses at pressure in a Wyoming field, a “residual CO2” in the liquid of 12.065 lbs/1,000 Bbls at 60 °F was determined. Applying this 12.065 lbs/1,000 Bbls to the total U.S. condensate production of some 291.8 MM Bbls (EIA 2008) results in a total dissolved CO2 of just slightly under 1,600 metric tonnes. Applying this same result to the total US crude production of some 1.5 trillion Bbls results in a total dissolved CO2 of about 10,600 metric tonnes.

The following table depicts the outcome of the process simulation:

[Table] Hydrocarbon CO2 Simulation

Hydrocarbon CO_2 Simulation						
	Inlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate
Temp, F	85	50	60	70	80	90
Pressure, psia	600	14.696	14.696	14.696	14.696	14.696
CO2, mol/hr	0.0014	0.000070	0.000061	0.000055	0.000048	0.000043
Total, mol/hr	0.6553	0.5375	0.5306	0.5231	0.5149	0.5058
CO2, mol%	0.21%	0.0131%	0.0116%	0.0104%	0.0093%	0.0085%
CO2, ppmv	2,136	131	116	104	93	85
CO2, lb/hr	0.0614	0.0031	0.0027	0.0024	0.0021	0.0019
Total, lb/hr	62.1565	56.7336	56.2801	55.7652	55.1773	54.5022
CO2, wt%	0.0988%	0.0055%	0.0048%	0.0043%	0.0038%	0.0035%
CO2, ppm mass	988	55	48	43	38	35
Total, bbl/day	6.15	5.4222	5.3711	5.3141	5.2504	5.1784
CO2, lb/Mbbl cond		13.721	12.065	10.839	9.599	8.806
Condensate 2008 MMbbls		291.8	291.8	291.8	291.8	291.8
CO2, tonne/yr		1,817	1,597	1,435	1,271	1,166
Crude 2009, MMbbl/d		5.32	5.32	5.32	5.32	5.32
CO2, lb/day		72,998	64,184	57,664	51,068	46,847
CO2, tonne/yr		12,084	10,624	9,545	8,453	7,755

Based on these low emissions, which combined equate to a cost in excess of $18,000 per tonne to comply with the proposed rule, API concludes that this source category is not justified. API requests that this source be excluded from the reporting rule due to its insignificant contribution to GHG emissions.

Response: EPA agrees with API that this source should be limited to CO_2 EOR operations only. Please see response to EPA-HQ-OAR-2009-0923-1011-21.
EPA notes the calculations on condensate CO_2 emissions, but would like to point out that the saturation of CO_2 in hydrocarbons could be much higher in EOR operations. Overall, EPA

intends to characterize CO_2 dissolved in hydrocarbon liquids leaving CO_2 EOR facilities and has limited the source to EOR operations only, which reduces the burden to report.

Comment Number: EPA-HQ-OAR-2009-0923-1151-53
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
39. Section 98.233(x) Hydrocarbon liquids dissolved CO2. The rule should state that this applies only to produced water associated with EOR operations. As currently written, ALL hydrocarbon liquids will require sampling for CO2. Additional details on this source type are provided in Sections VI and VII.

Response: EPA agrees with the comment about hydrocarbon liquids at CO_2 EOR facilities. Please see the response to EPA-HQ-OAR-2009-0923-1011-21 for further details.
In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129

Comment Number: EPA-HQ-OAR-2009-0923-1305-27
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
S. Section 98.233(x) Hydrocarbon liquids dissolved CO2

If this source type is not eliminated from the final rule, it should state that this applies only to produced water associated with CO2 EOR operations. As currently written, ALL hydrocarbon liquids will require quarterly sampling and analysis for dissolved CO2. Similar to the GHG volumetric emissions and Produced Water Dissolved CO2, BP requests that the EPA allow for annual and representative samples. This change will not disrupt or misrepresent the reported emissions; however, it will greatly reduce manpower and cost requirements to gather this information. See comment #13 under EPA solicited comments for additional background and context for this recommendation.

Response: : EPA agrees with the comment about annual sampling of hydrocarbon liquids at CO_2 EOR facilities. Please see the response to EPA-HQ-OAR-2009-0923-1011-21 and EPA-HQ-OAR-2009-0923-1058-13 for further details.
In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1305-54
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
M. Section 98.233(x) Hydrocarbon liquids dissolved CO2

In the Technical Support Document (TSD), dissolved CO2 in hydrocarbon liquids is discussed only in relation to CO2 EOR operations. However, the proposed rule applies the category to all onshore production. If EPA does retain this source category in the final rule, it should be restricted to just CO2 EOR operations rather than the broader industry.

BP believes the potential GHG emissions captured from this source category do not justify the costs of quarterly sampling of every hydrocarbon tank in the oil and gas production industry. Based on a HYSYS simulation using an average of 4 condensate streams that had CO2 analyses at pressure in a Wyoming field, a "residual CO2" in the liquid of 12.065 lbs/1,000 Bbls at 60 °F was determined. Applying this 12.065 lbs/1,000 Bbls to the total U.S. condensate production of some 291.8 MM Bbls (EIA 2008) results in a total dissolved CO2 of just slightly under 1,600 metric tonnes. Applying this same result to the total US crude production of some 1.5 trillion Bbls results in a total dissolved CO2 of about 10,600 metric tonnes.

The following table depicts the outcome of the HYSYS simulation:

[Table] Hydrocarbon CO2 Simulation

Hydrocarbon CO2 Simulation							
	Inlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate	Outlet Condensate
Temp, F	85	50	60	70	80	90	100
Pressure, psia	600	14.696	14.696	14.696	14.696	14.696	14.696
CO2, mol/hr	0.0014	0.000070	0.000061	0.000055	0.000048	0.000043	0.000039
Total, mol/hr	0.6553	0.5375	0.5306	0.5231	0.5149	0.5058	0.4957
CO2, mol%	0.21%	0.0131%	0.0116%	0.0104%	0.0093%	0.0085%	0.0078%
CO2, ppmv	2,136	131	116	104	93	85	78
CO2, lb/hr	0.0614	0.0031	0.0027	0.0024	0.0021	0.0019	0.0017
Total, lb/hr	62.1565	56.7336	56.2801	55.7652	55.1773	54.5022	53.7228
CO2, wt%	0.0988%	0.0055%	0.0048%	0.0043%	0.0038%	0.0035%	0.0032%

CO2, ppm mass	988	55	48	43	38	35	32
Total, bbl/day	6.15	5.4222	5.3711	5.3141	5.2504	5.1784	5.0967
CO2, lb/Mbbl cond		13.721	12.065	10.839	9.599	8.806	8.005
Condensate 2008 MMbbls		291.8	291.8	291.8	291.8	291.8	291.8
CO2, tonne/yr		1,817	1,597	1,435	1,271	1,166	1,060
Crude 2009, MMbbl/d		5.32	5.32	5.32	5.32	5.32	5.32
CO2, lb/day		72,998	64,184	57,664	51,068	46,847	42,588
CO2, tonne/yr		12,084	10,624	9,545	8,453	7,755	7,050

Based on the low emissions coupled with the high cost of quarterly sampling and analysis the cost per tonne covered is excessive and this source category should be dropped due to its insignificant contribution to GHG emissions.

Response: EPA disagrees with the commenter about excluding the hydrocarbon liquids source altogether from the rule. However, EPA has made changes to the requirements to limit the source to EOR operations with simplified monitoring requirements. Please see responses to EPA-HQ-OAR-2009-0923-1011-21 and EPA-HQ-OAR-2009-0923-1058-13 for further details. In regards to the condensate calculation, please see response to EPA-HQ-OAR-2009-0923-1151-128 for further details.

13.2.11.2 PRODUCED WATER

Comment Number: EPA-HQ-OAR-2009-0923-0582-41
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Produced Water Dissolved CO2

Source Description: Enhanced Oil Recovery operations using injection of CO2 have produced water that has dissolved CO2.

Measurement Options: The approach recommended by USEPA was considered to be implementable without undue burden and sufficiently accurate to support a cap and trade rule. No other options were evaluated by WCI.

USEPA Approach:

The re-proposed subpart W contains the following method for the determination of CO2 emissions in produced water

Step 1: Determine the amount of CO2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in SECTION 98.234(b) to determine retention of CO2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. Use the average of the quarterly analysis for the reporting period.

Step 2: Estimate emissions using the Equation W-26 of this section.

Mass, CO2 = Spw * Vpw (Eq. W-26)

Where:

Mass, CO2 = Annual CO2 emissions from CO2 retained in produced water beyond tankage, in metric tons.
Spw = Amount of CO2 retained in produced water in metric tons per barrel, under standard conditions.
Vpw = Total volume of produced water produced in barrels in the reporting year.

EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from calculations in Step 1 and 2.

WCI Recommendation: We recommend using the approach provided by USEPA without any modification.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1024-32
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
10. Produced water dissolved CO2. Kinder Morgan requests that this source be excluded from the reporting rule due to its insignificant contribution of GHG emissions. EOR operations that route produced water from separation directly to reinjection into the hydrocarbon reservoir in a closed loop system without leakage to the atmosphere are exempt from SECTION 98.233(y). This exemption from paragraph (y) should also apply to EOR operations that route produced water from separation directly to disposal. As currently written, all produced water will require sampling for CO2, which would be cost prohibitive.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1042-25
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
§98.233(y) Produced water dissolved CO2

ConocoPhillips Comment:

To emphasize API comment, this source should be excluded from the reporting rule due to its insignificant contribution to GHG emissions. If EPA disagrees with this statement, EPA should clarify that this paragraph applies only to produced water associated with CO2 EOR operations. On page 53 of the TSD, EPA discusses the concern with dissolved CO2 in produced water in relation to EOR operations. Limiting this paragraph to only produced water associated with CO2 EOR operations, as appears to be EPA's intent, will significantly reduce the resource and analytical burden.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1060-24
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
Source Type:
Produced water dissolved CO2

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(y)

Monitoring requirements/parameters:
1. Amount of CO2 retained in produced water in metric tons per barrel, under standard conditions
2. Total volume of produced water produced in barrels in the reporting year

Comment:
It seems the EPA is assuming that the entrained CO2 will eventually be released, but it is unclear

why this assumption is being made. Further, it seems that the level of effort is not commensurate with the amount of CO2 even the EPA expects to be emitted from this source. Also, this source is not addressed in The Climate Registry's protocol for Oil and Natural Gas GHG reporting, which is largely a more-inclusive program than EPA. If TCR did not address this as a source of emissions, it is possible that this source is not expected to be a significant emitter of GHGs.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1073-1
Organization:
Commenter: Michael Leonard

<u>Comment Excerpt Text:</u>
(98.233 (y)) includes Produced water dissolved CO2 emissions as a source of emissions to be reported. On Page 18621 of the Federal Register, Item (2) Engineering First Principle Methods, 4th paragraph of the Subpart W preamble it states: "The supplemental proposed rulemaking does not include emissions from tanks containing primarily water with the exception of transmission station condensate tanks where dump valves are determined to be bypassing gas. Therefore, EPA seeks comments on how to quantify emissions from tanks storing water without resulting in additional reporting burden to the facilities." The source type Produced water dissolved CO2 in the proposed rule and the statement in the preamble are contradictory. Please clarify the intentions of Subpart W relating to water storage tanks

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1074-40
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.233(y)(1):

Regarding the requirement for quarterly sampling, WBIH strongly requests a one-time sample requirement. A sample is taken when the well begins production and that analysis will be used to calculate emissions. Quarterly sampling is not required for current air quality compliance conditions and would be extremely burdensome and costly, which EPA has likely significantly underestimated the cost involved with quarterly sampling. For a cost example, in one production field, there could be 1,000 wells, each with a production water pit. For this number of wells, there would be 4,000 sampling and analysis events annually. This will cost approximately $1,000,000 per year for analyses, with an additional cost for labor, just in one field

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1151-129
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Q. Section 98.233(y) Produced water dissolved CO2

In the Technical Support Document (TSD), dissolved CO2 in produced water is discussed in relation to CO2 Enhanced Oil Recovery (EOR) operations. However, the proposed rule applies the category to all onshore production. EOR and all produced water streams are managed for minimal dissolved CO2 in produced water due to the severity of corrosion.

API believes the potential GHG emissions captured from this category do not justify the estimated costs of some $323.1 million per year. Based on the maximum solubility of CO2 in both pure water and sea water, API estimates the theoretical maximum dissolved CO2 in the 14.1 trillion barrels of produced water generated in 2008 (extracted from IHS provided production data) as 4.7 MM metric tons, with an equilibrium saturation for fresh water of 2.1 grams/kg (from online "Engineering Toolbox") at 15 degrees C and less than 3.6 MM metric tons at an equilibrium saturation for sea water of 1.55 grams/kg[232] if all produced water were CO2 saturated. In actual practice, most produced waters would not approach the saturation point and actual dissolved CO2 would be a small fraction of this theoretical maximum.

The following tables depict API's analysis of the theoretical CO2 content in produced water:

Fresh Water Case							
Bbls Produced Water	Gallons per Bbl	lbs per gal	lbs per kg	gr CO_2 per kg	gr per lb	lbs per metric ton	metric tons
14,100,000,000	42	8.34	0.45359	2.1	453.6	2204	4,705,815

Sea Water Case							
Bbls Produced Water	Gallons per Bbl	lbs per gal	lbs per kg	gr CO_2 per kg	gr per lb	lbs per metric ton	metric tons
14,100,000,000	42	8.57	0.45359	1.55	453.6	2204	3,570,793

API believes that this source category should not be included in the final rule. The estimated emissions based on the theoretical maximum CO2 are much larger than would be found in practice. API requests that this source be excluded from the reporting rule due to its insignificant contribution to GHG emissions.

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[232] "Solubility of Carbon Dioxide in Pure Water, Synthetic Sea Water, and Synthetic Sea Water Concentrates at -5° to 25° C. and 10- to 45-Atm. Pressure"; PAUL B. STEWART and PREM MUNJAL1; Sea Water Conversion Laboratory and Department of Mechanical Engineering, University of California, Berkeley, Calif. 94720; Journal of Chemical and Engineering Data, Vol. 15, No. 1, 1970.

Response: EPA had intended produced water dissolved CO2 to be reported by EOR operations only. However, EPA agrees with the calculation provided by API and has determined that the emissions from produced water at EOR facilities may not significant enough to warrant reporting at this point. Hence, today's rule does not require the monitoring of CO2 from produced water at any onshore petroleum and natural gas production operations.

Comment Number: EPA-HQ-OAR-2009-0923-1151-54
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
40. Section 98.233(y)(3) Produced water dissolved CO2. As demonstrated in Section VII.Q of this document, API requests that this source be excluded from the reporting rule due to its insignificant contribution of GHG emissions. EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without leakage to the atmosphere are exempt from paragraph (y). This exemption from paragraph (y) should also apply to EOR operations that route produced water from separation directly to disposal. As currently written, ALL produced water will require sampling for CO2 which would be cost prohibitive. API recommends that the rule not require produced water dissolved CO2 sampling. Additional details on this source type are provided in Sections VI and VII.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1151-93
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
- Section 98.232(c)(20) and Section 98.233(y): Similar to the Hydrocarbon Liquids Dissolved CO2 category is the Produced Water Dissolved CO2 category. Again, EPA's Technical Support Document only discusses this category in relation to CO2 EOR operations that route water directly from separation to atmospheric storage tanks prior to recycle. However, the rule requires quarterly sampling and analysis of the produced water directly following separation (presumed to be at separator pressures) for all produced water streams. The proposed rule also requires determination of the CO2 retained in the produced water at standard temperature and pressure conditions – presumably through use of a process model or laboratory GOR methodology, although the rule is silent on the methodology. (Please note that the efficacy of this category is discussed in another API comment specific to the source category provided in Section VII.Q.) As with hydrocarbon tanks, this source requires measuring the CO2 in the produced water immediately downstream of the separator, so an estimate of separators is used to evaluate the costs. Assuming 308,000 separators require sampling, and applying a conservative estimated cost of $475 per sample for the analysis, this yields a cost of $585 MM just for the required sampling

and analysis. Adding a low estimate of 0.5 hours per tank for modeling of CO2 content at STP (or an additional $50 per analysis for a laboratory GOR) yields an additional cost of $15.4 MM for a total cost estimate of $600 MM. Note, this cost estimate is assumed to include produced water from coal-bed methane operations.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1155-27
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
25. CO2 Enhanced Oil Recovery Operations

We support EPA's proposed emission estimating method for CO2 released from petroleum and produced water in storage tanks at Enhanced Oil Recovery (EOR) Operations based on composition and volume.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1305-28
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
T. Section 98.233(y)(3) Produced water dissolved CO2

If this source type is not eliminated from the final rule, it should state that this applies only to produced water associated with CO2 EOR operations. As currently written, ALL produced water will require sampling for CO2. Similar to the GHG volumetric emissions and Hydrocarbon Liquids Dissolved CO2, BP requests that the EPA allow for annual and representative samples. The proposed regulation requires that we sample and determine the CO2 content at the outlet of each oil and water separation vessel. At many production facilities, plants have multiple separators in series and multiple parallel separation trains. If the intent of this source category is to capture produced water dissolved CO2 which may evolve in produced water tanks, only a representative sample at the outlet of the last oil and water separation vessel should be required. As reservoir fluids will be consistent throughout the year an annual sample is adequate to estimate these emissions. If EPA chooses to keep this source category, BP requests that only an annual and representative sample be required at the outlet of the last oil and water separator upstream of the feed to the produced water tanks. This change will not disrupt or misrepresent the reported emissions; however, it will greatly reduce manpower and cost requirements to gather this information.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

Comment Number: EPA-HQ-OAR-2009-0923-1305-56
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
O. Section 98.233(y) Produced water dissolved CO2

The only place that dissolved CO2 in produced water is discussed in the proposed rule documents is in the TSD and only in relation to CO2 EOR operations – however, the rule applies the category to all onshore production. If EPA does retain this source category in the final rule, it should be restricted to just CO2 EOR operations rather than the broader industry.

BP believes the potential GHG emissions captured from this category do not justify the costs inherent in sampling and analyzing produced water from every separator in the oil and gas production sector. Based on the maximum solubility of CO2 in both pure water and sea water we estimate the theoretical maximum dissolved CO2 in the 14.1 trillion barrels of produced water generated in 2008 (extracted from IHS provided production data) as less than 3.4 MM metric tons with an equilibrium saturation for fresh water of 1.5 grams/kg (from online "Engineering Toolbox") at 20 degrees C and about 3 MM metric tons at an equilibrium saturation for sea water of 1.325 grams/kg (from "'Solubility of Carbon Dioxide in Pure Water, Synthetic Sea Water, and Synthetic Sea Water Concentrates at -5° to 25° C. and 10- to 45-Atm. Pressure"; PAUL B. STEWART and PREM MUNJAL1; Sea Water Conversion Laboratory and Department of Mechanical Engineering, University of California, Berkeley, Calif. 94720; Journal of Chemical and Engineering Data, Vol. 15, No. 1, 1970) if all produced water were CO2 saturated. In actual practice, most produced waters would not approach the saturation point and actual dissolved CO2 would be a small fraction of this theoretical maximum.

The following tables depict this analysis of the theoretical CO2 content in produced water:

Fresh Water Case							
Bbls Produced Water	Gallons per Bbl	lbs per gal	lbs per kg	gr CO2 per kg	gr per lb	lbs per metric ton	metric tons
14,100,000,000	42	8.34	0.45359	2.1	453.6	2204	4,705,815
Sea Water Case							
Bbls Produced Water	Gallons per Bbl	lbs per gal	lbs per kg	gr CO2 per kg	gr per lb	lbs per metric ton	metric tons
14,100,000,000	42	8.57	0.45359	1.55	453.6	2204	3,570,793

BP believes that this source category should not be included in the final rule. The emissions estimated based on the theoretical maximum CO2 are much larger than would be found in practice and do not justify the projected costs associated with this source category. BP requests that this source be excluded from the reporting rule due to its insignificant potential contribution to GHG emissions.

Response: In today's final rule, EPA does not require the monitoring of CO_2 from produced water at any onshore petroleum and natural gas production operations. For further clarification, please see the response to EPA-HQ-OAR-2009-0923-1151-129.

13.2.12 PORTABLE EQUIPMENT COMBUSTION EMISSIONS

Comment Number: EPA-HQ-OAR-2009-0923-1058-8
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
98.230 Definition of the source category.
We feel that the inclusion of portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment…rented or contracted equipment) with onshore petroleum and natural gas production creates a large tracking burden on reporting entities in this category. Often times this equipment is transferred from reporting unit to reporting unit depending on development needs. In addition rented equipment (i.e., well drilling, completion and workover) location is not controlled by reporting companies. Rental companies have multiple contracts in place with companies to frequently mobilize equipment to multiple companies and reporting areas.

Response: EPA disagrees with the commenter on emissions from portable equipment. The emissions contribution from portable equipment is significant enough to warrant data collection. Please see the responses to EPA-HQ-OAR-2009-0923-1015-35 and EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-0582-19
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
WCI recommends that SECTION 98.233(z) (Portable Equipment Combustion) be deleted and the following paragraph be added to SECTION 98.232

(m) You must report the emissions of CO_2, CH_4, and N_2O from each portable equipment combustion source. For portable equipment combustion sources that combust field gas, you must report under this subpart. For portable equipment combustion sources that combust fuels other than field gas, you must report under subpart C of this part (General Stationary Combustion Sources) using the methods required for stationary combustion sources.

Response: EPA disagrees with the commenter. However, EPA has clarified the overlaps between Subparts C and W in regards to reporting of combustion emissions. For further details, please see response to EPA-HQ-OAR-2009-0923-1060-27.

Comment Number: EPA-HQ-OAR-2009-0923-1024-23
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Clarification of When Portable Equipment Should Be Included. Kinder Morgan requests that EPA eliminate its proposal to require reporting of emissions from portable non-self-propelled equipment at onshore petroleum and natural gas production facilities. Including portable equipment in Subpart W greatly magnifies the reporting burden for the onshore petroleum and natural gas production sector, while only marginally increasing the coverage of the proposed rule. Moreover, the TSD provides scant data or analysis to support the inclusion of portable equipment in the Mandatory Reporting Rule; in fact, the TSD concedes that EPA does not even have an estimate of disaggregated emissions from stationary and portable combustion devices in the onshore petroleum and natural gas production sector.[233]

If EPA proceeds to require the inclusion of portable equipment in Subpart W, Kinder Morgan requests that EPA provide clarification as to which equipment is covered. Specifically, proposed 40 C.F.R. SECTION 98.231(b) states that emissions from portable equipment that is stationed at a wellhead for more than 30 days in a reporting year must be included when determining the applicability of the rule. This requirement is overbroad, in that it sweeps in portable equipment that is not stationed at production wellheads, as opposed to storage wellheads. EPA should revise the Mandatory Reporting Rule to clarify that only portable equipment stationed at production wellheads is to be included in applicability determinations and emission reports.

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[233] TSD, at 34.

Response: EPA disagrees with the commenter. EPA has estimated that emissions from portable equipment contribute to 45% of the total emissions from oil and gas production; please see "Portable Combustion Emissions" memo under rulemaking docket EPA-HQ-OAR-2009-0923. Hence it is not consistent with the broader objectives of the rule, which is to get reasonable coverage of emissions to inform future policy, to drop portable equipment that are a significant source of emissions from reporting.

EPA is not clear on the citation of the TSD footnote by the commenter. The very fact that EPA does have disaggregated stationary and combustion emissions warrants the need to collect such information. In today's final rule, EPA has provided a limited list of portable equipment that needs to be reported for emissions, thus reducing the burden to report combustion emissions. EPA has also provided an equipment threshold for external combustion equipment in onshore production and natural gas distribution. Emissions from external combustion equipment equal to or less than 5 mmbtu per hour are not required to be reported; however, equipment count by type has to be reported. Finally, EPA has removed the 30-day clause from today's final rule. Please see response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Please refer to the Section 3, "Summary of Comments and Responses" of the preamble to today's final rule for the response to these issues.

Comment Number: EPA-HQ-OAR-2009-0923-1027-12
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.233(z): Calculate emissions from portable equipment using the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources).

OOC Comment: The rule should clarify that this subsection does not apply to offshore platforms. Section 98.232 lists the GHG's to report. Subsections 98.232 (b) to (i) lists them by industry segment, and only subsection (b) applies offshore. The remaining subsections, 98.232 (j) to (l), do not include portable equipment combustion emissions. Thus, for offshore sources portable equipment combustion emissions do not have to be reported. The only subsection where portable equipment arguably have to be considered for offshore platform is subsection 98.231(b) dealing with threshold calculation. However, that would result in use of Subpart C methodology to help determine Subpart W threshold applicability. It is doubtful that this was the intended result.

Response: EPA has provided clarification in today's final rule that the Section 98.233(z) indicated by the commenter applies to onshore production and natural gas distribution sources. Offshore reporters shall report the emissions as calculated under BOEMRE compliance with 30 CFR 250.302 through 304.

Comment Number: EPA-HQ-OAR-2009-0923-1042-26
Organization: ConocoPhillips Company

Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
98.233(z) Portable equipment combustion emissions

ConocoPhillips Comment:

§98.233(z) seems to require annual reporting of emissions from portable emission units. This conflicts with what appears to be EPA's intent, as noted on page 18619 of the rule preamble, to use portable sources for applicability only. Portable sources should not be part of the annual reports since those emissions are accounted for by the refiners who supply their fuel. We request that EPA clarify this point by removing §98.233(z) from the rule before it is finalized.

Response: EPA agrees that the rule proposal may have caused some confusion in regard to the portable combustion emissions requirement. In today's final rule, EPA has clarified that for onshore production both portable and stationary combustion emissions must be included in both the determination of threshold and for reporting of emissions. In addition, for natural gas distribution stationary combustion emissions must be included in both the determination of threshold and for reporting of emissions.

EPA disagrees with the commenter on exclusion of portable sources due to reporting of refineries under Subpart MM. Although refineries will report total fuel supplied under Subpart MM, EPA will not know where the fuels are being combusted to inform any combustion equipment specific policy. Furthermore, onshore production combustion equipment typically use field gas (or produced natural gas) that is not reported under Subpart MM or Subpart NN and EPA intends to capture these emissions under Subpart W. For further details on double counting of emissions, please see Section II.D of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). Hence, in today's final rule, EPA has retained the requirement for portable equipment emissions to be reported.

Comment Number: EPA-HQ-OAR-2009-0923-1060-27
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
Source Type:
Combustion Equipment (including, but not limited to, engines, turbines, generators)

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(z)

Monitoring requirements/parameters:
1. For portable combustion equipment, use the Tier 1 methodology of Subpart C. The only monitoring requirement for Tier 1 is annual fuel consumption.
2. For stationary combustion equipment, follow the requirements of Subpart C.

There are several issues here: Does the 25,000 tonne threshold include all combustion equipment in the basin for production facilities? Does this regulation bring all facilities reporting under Subpart C into one larger facility under Subpart W? It is unclear how facilities required to report under Subpart C by the standard definition of "facility" would also report under Subpart W. Yates again requests clarification/removal of portable combustion equipment

Response: For onshore production, all portable and stationary combustion emissions in the reporting basin must be included in the 25,000 $MtCO_2e$ threshold determination. However, emissions from external combustion sources with a rated heat input capacity equal to or less than 5 mmBtu/hr are not included in the threshold determination (however, activity count has to be provided). For threshold determination the reporter must combine emissions and follow the requirements of 98.2, for facilities that contain any source category for which calculation methods are provided.

In regards to reporting of combustion emissions, onshore production and LDCs, will report to Subpart W under the common facility definition. All other segments in today's final rule will report combustion emissions to Subpart C. For reporting of combustion emissions from LDCs, please see the response to EPA-HQ-OAR-2009-0923-1009-2.

For onshore petroleum and natural gas production, and natural gas distribution, all combustion emissions monitoring and reporting requirements have been moved to Subpart W in today's final rule. Hence, data reporting for the onshore petroleum and natural gas, and natural gas distribution sectors combustion emissions starting 2011 shall be under Subpart W (note that for year 2010 onshore production and natural gas distribution reporters have to comply with requirements of Subpart C for combustion emissions, the switch is in force beginning 2011). This change will avoid any conflicts with onshore production and natural gas distribution facility definitions for combustion emissions between Subparts C and W.

Comment Number: EPA-HQ-OAR-2009-0923-1080-38
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>
Aka recommends that EPA remove the requirement of §98.236(f) which states that an operator must report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters. However, EPA specifically exempts portable equipment from the definition of the stationary fuel combustion source category in Subpart C of the rule. It is inconsistent and burdensome to require the inclusion of portable sources for the petroleum and natural gas systems subject to Subpart W.

Response: EPA disagrees with the commenter with the exclusion of portable equipment from today's final rule. However, EPA has provided an equipment threshold for external combustion equipment in onshore production and natural gas distribution. For further clarification, please see the responses to EPA-HQ-OAR-2009-0923-1024-23 and EPA-HQ-OAR-2009-0923-1060-27.

With regard to control and maintenance of equipment by third-party contractors, please see the response to EPA-HQ-OAR-2009-0923-1170-7.

Comment Number: EPA-HQ-OAR-2009-0923-1170-7
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:
Portable equipment should not be included - ie: drilling rigs

As an alternative to the request in point 5, if reporting emissions from all combustion sources in Subpart W-applicable basins is required in the final rule, reporting emissions from portable equipment should not be included. In Subpart C, portable equipment is specifically excluded; however, Subpart W, 98.231 (b) states "By applying the threshold defined in 98.2{a){2}, you must include combustion emissions from portable equipment that cannot move on roadways under its own power or drive train and that is stationed at a wellhead for more than 30 days in a reporting year, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters." Complying with this requirement as proposed would be complex and resource intensive, since this equipment is often moved from well to well or among operators. Further, much of this equipment, especially compressors, drilling, completion, and workover equipment, are contracted from a third party. When the operator does not own the equipment or control the operation or maintenance of the equipment, they likely do not have the operational data to perform the needed calculations and/or necessary records to certify the accuracy of the GHG emissions data. Further, since this equipment is transient in nature, it does not accurately represent continuous emissions at a facility. This would be impracticable to track and could result in double-counting. Further, this section is unclear as to the 30-day requirement, if the equipment is moved to various wells by the same operator in the same basin, or between basins, etc ... Last, it is difficult to anticipate if a drilling rig, for example, will remain in a location longer than 30 days.

Response: EPA disagrees with the commenter on not including portable equipment emissions reporting. For further details on why portable equipment emissions are required to be reported, please see response to EPA-HQ-OAR-2009-0923-1024-23.

EPA expects the reporting entity to collect relevant information from their contractors if need be on portable equipment such as drilling rig emissions. The owner or operator that contracts a third party has authority over the actions of that contractor and therefore the reporter must require the contractor to provide the relevant information. For further details, please see response to EPA-HQ-OAR-2009-0923-1031-21 for further details. Finally, EPA has in today's final rule removed the 30-day at wellhead clause to avoid practical issues with determining the time the portable equipment is at the wellhead. Therefore, portable equipment located in non-reporting facilities need not be tracked. Also, reporters will not have the additional burden of tracking the number of days the portable equipment is operating in reporting facilities; reporters have to simply report emissions from portable equipment located in the basin for the period it is in the basin.

Furthermore, the equipment threshold for external combustion emissions will ensure that equipment that is below this threshold does not have to be tracked.

Comment Number: EPA-HQ-OAR-2009-0923-1173-15
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
Emissions from Portable / Non-self Propelled Equipment

Resolute Comments:

Resolute strongly opposes the requirement to report the emissions from non-stationary and portable sources, especially well drilling rigs and ancillary equipment for well completions and workovers. As is common practice in the industry, Resolute contracts with service companies to drill and complete its wells. Complying with this requirement as proposed would be very resource intensive and complex since this equipment is often moved from well to well, between operators, and even between geologic basins. In addition, since this equipment is controlled and maintained by third-party contractors, Resolute does not have access to the necessary information or data to report their emissions, or to certify as to the quality of any data that Resolute might be able to obtain. All other Clean Air Act programs establish applicability based on whether a party owns and/or operates a source because it is not feasible for someone who does not control the day-to-day operation of a source to collect the required information or monitor the source's usage. No other industry sector is required to report contractor's emissions under EPA's MRR, and it should not be required under Proposed Subpart W.

Response: EPA disagrees with the commenter on the exclusion of portable equipment emissions reporting. For further details, please see response to EPA-HQ-OAR-2009-0923-1024-23. With regard to control and maintenance of equipment by third-party contractors, please see the response to EPA-HQ-OAR-2009-0923-1170-7.

Comment Number: EPA-HQ-OAR-2009-0923-1173-7
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
EPA should not require the reporting of emissions from non-stationary and portable sources.

Response: EPA disagrees with the commenter on the exclusion of portable equipment emissions reporting. For further details, please see response to EPA-HQ-OAR-2009-0923-1024-23.

Comment Number: EPA-HQ-OAR-2009-0923-1305-30
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:

Section 98.233(z). Portable Equipment Combustion Emissions

EPA has indicated that they are especially interested in the significant sources of portable combustion emissions of GHGs. To reduce the reporting burden for sources that are normally owned and operated by a 3rd party, we recommend the requirement for this source be limited to drill rigs, completion activities and compressors. In addition, to eliminate double counting of emissions, this source category should exclude reporting emissions associated with burning fuels subject to reporting under Subpart MM or burning NGLs subject to reporting under NN.

Response: In today's final rule, EPA has restricted the list of portable combustion equipment required to report. However, EPA disagrees with limiting the list to just drill rigs and rental compression. For further details, please see response to EPA-HQ-OAR-2009-0923-1060-27. EPA disagrees with the exclusion of emissions associated with burning fuels under subpart MM and burning NGLs under NN. For further details, please see the response to EPA-HQ-OAR-2009-0923-1042-26.

Comment Number: EPA-HQ-OAR-2009-0923-3522-2
Organization: Heath Consultants
Commenter: Milton W. Heath

Comment Excerpt Text:
Recommended Leak Threshold

In order to provide a solution as to what defines a leak using either the imaging camera, electronic gas screeners/detectors, infrared leak detectors or other devices, it is our opinion that the leak should ultimately be determined on whether or not it can be measured with a high volume sampler. This portable intrinsically safe measurement tool uses catalytic oxidation, thermal conductivity hydrocarbon sensors to measure the gas concentration off the main sample tube. A leak rate of 0.01 scfm can be measured which if leaking annually would amount to approximately 5 Mcf or twenty-one dollars of gas at $4/Mcf. This is arguably small but at least a threshold whereby the value of the gas can be determined and the economics of fixing the leak known compared to the cost of repair.

Response: EPA disagrees with the commenter. Requiring direct measurement to comply with a leak definition is onerous to reporters in terms of burden to report. Hence, EPA does not require direct measurement to define a leak.

Comment Number: EPA-HQ-OAR-2009-0923-1151-55
Commenter: Karin Ritter
Organization: American Petroleum Institute, Karin Ritter

Comment Excerpt Text:
Section 98.233(z). Portable Equipment Combustion Emissions. EPA has indicated that they are especially interested in the significant sources of portable combustion emissions of GHGs. To reduce the reporting burden for sources that are normally owned and operated by a 3rd party,

API recommends the requirement for this source be limited to drill rigs and rental compression. In addition, to eliminate double counting of emissions, this source category should exclude reporting emissions associated with burning fuels subject to reporting under Subpart MM or burning NGLs subject to reporting under NN.

Response: In today's final rule, EPA has restricted the list of portable combustion equipment required to report. However, EPA disagrees with limiting the list to just drill rigs and rental compression. For further details, please see response to EPA-HQ-OAR-2009-0923-1060-27. EPA disagrees with the exclusion of emissions associated with burning fuels under subpart MM and burning NGLs under NN. For further information, please see the response to EPA-HQ-OAR-2009-0923-1042-26.

VOLUME 14: DEFINITIONS AND BOUNDARIES

14.0 DEFINITIONS AND BOUNDARIES

Comment Number: EPA-HQ-OAR-2009-0923-1024-50
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
SECTION 98.238 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Natural gas distribution facility means the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

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

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

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

Response: EPA disagrees with the commenters suggested change to the definition of onshore petroleum and natural gas production facility to “equipment associated with a well.” EPA considered and evaluated coverage of the onshore production segment at different reporting thresholds and facility definitions, ranging from wellheads to fields to basins, arriving at a conclusion that the basin definition was the most cost effective and reasonable coverage at the 25,000 tCO_2e threshold. For further details, please see response to comment EPA-HQ-OAR-2009-0923-1167-1.

Comment Number: EPA-HQ-OAR-2009-0923-1024-14
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:

Segmentation of the Petroleum and Natural Gas Sector. The proposed definitions of individual segments of the petroleum and natural gas industry[234] contain unclear and overlapping references to operations and equipment, and are impracticable for multipurpose or co-located facilities. Many facilities owned or operated by companies in the petroleum and natural gas sector, including Kinder Morgan, have equipment from multiple industry segments (processing, production, etc.) located in the same physical space. Many facilities also serve more than one purpose, such as both transmission and storage, or processing and transmission. The proposed definitions do not provide guidance as to how facilities that serve or house multiple functions should be categorized. Nor do the definitions provide the necessary certainty as to where the physical boundaries of facilities should be drawn. This is a concern not just for multipurpose facilities, but for facilities such as gas processing plants that are often surrounded by miles of gathering pipelines and associated equipment owned and operated by multiple parties. Kinder Morgan's proposed changes to the definitions, which are provided in Appendix A, will clarify the rule and increase the likelihood of accurate and consistent reporting.

As a supplement to the existing array of definitions, Kinder Morgan also supports INGAA's suggestion to link the source category definitions to the primary North American Industrial Classification System (NAICS) six-digit code that facilities would be required to report under the revisions to Subpart A proposed on April 12, 2010.[235] This approach would provide a straightforward way of classifying facilities, and would therefore help avoid misclassification of facilities or equipment in the facilities and improve the ability of entities in the petroleum and natural gas sector to submit consistent and accurate reports to EPA. If necessary, reporting entities could provide additional information in their monitoring plan to justify the classification of a facility whose NAICS code encompasses more than one of the facility types defined in the proposed 40 C.F.R. SECTION 98.230(a)(1). The source category definitions should include references to NAICS as follows:

- Offshore petroleum and natural gas production – 21111

- Onshore petroleum and natural gas production - 211111

- Onshore natural gas processing plants – 211112

- Onshore natural gas gathering compression – 486210

- Onshore natural gas transmission compression – 486210

- Underground natural gas storage – 486210

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[234] 40 C.F.R. SECTION 98.230(a).

[235] Mandatory Reporting of Greenhouse Gases: Rule Amendment, 75 Fed. Reg. 18,455, 18,467 (Apr. 12, 2010) (proposed amendments to 40 C.F.R. SECTION 98.3).

- Liquefied natural gas (LNG) storage – 486210

- LNG import and export equipment – 486210

- Natural Gas Distribution – 221210

Kinder Morgan suggests that a new source category for onshore natural gas gathering compression be included in this the list, as more fully explained in Section II.B.5 of these comments.

Response: In developing the petroleum and natural gas industry segment definitions EPA considered the possibilities of multi-purpose facilities (e.g. transmission compressor stations that alternate as gas storage compression) and operating sites with equipment from more than one industry segment (e.g. transmission compression station with a gas processing straddle facility). Because there are so many possible combinations of equipment that can serve multiple purposes and operating locations with multiple industry segments represented, EPA concluded that it would be intractable to define industry segments in such a way that only one industry segment would be clear for every possible combination. EPA also considered that the emissions estimation methodologies are the same for segments that have or share similar equipment as other segments (e.g. processing, transmission, gas storage, LNG compressors). Today's final rule requires the reporter to determine the industry segment for which the majority of emissions occur and report all equipment within that facility for which there is a method defined. EPA recognizes that some data may not be reported where the obvious industry segment (e.g. processing facility) has one or a few producing wells inside the facility fence and the processing facility owner/operator does not have enough production emissions in the basin surrounding the processing facility to meet the reporting threshold under onshore production. EPA concludes that such random missing data will not impact the overall inventory's ability to inform policy.

Where a piece of equipment serves a dual purpose, such as a transmission compressor operating part time as a gas storage compressor, the rule requires this piece of equipment to be reported under the majority use industry segment. EPA concluded that most of the potential dual-purpose equipment will have the same emissions reporting requirements in either industry segment, so reporting under only one majority use segment will avoid double counting.

EPA disagrees with the comment on the use of the term "facility," as EPA has used the term "facility" consistently across the entire MRR to collect necessary GHG data. Please see response to comment EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923). EPA considered the addition of NAICS codes in the definition of industry segments, and rejected this because the codes are not sufficiently unique to add differentiation to some industry segments. For example, one NAICS code, 486210, applies to Onshore natural gas gathering compression, Onshore natural gas transmission compression, Underground natural gas storage, Liquefied natural gas (LNG) storage, and LNG import and export equipment. Please see response to comment EPA-HQ-OAR-2009-0923-1039-6.

Comment Number: EPA-HQ-OAR-2009-0923-1024-18
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Gathering Facilities Should Report Separately and in the Same Manner as Natural Gas Transmission Compression Facilities. EPA's proposal to designate gathering pipelines as part of onshore petroleum and natural gas production and onshore natural gas processing plants[236] does not conform to the structure of the industry. Gathering compression facilities and pipelines have never been considered by the industry to be "part of" onshore production facilities or processing plants. Nor has EPA grouped gathering compression facilities and pipelines together with these facilities in its other CAA programs, such as NSPS.[237] Even setting these considerations aside, it is difficult to see how a reporting entity that owns a processing plant or production well could properly take gathering systems emissions into account, considering the complexity and multiple ownership and operating arrangements of gathering pipeline networks. Gathering pipelines can extend for miles around a processing facility or production area. Multiple different gathering pipelines owned by multiple different entities are often connected to the same processing facility or production area. Gathering pipelines and the associated compressor stations can often have the ability to deliver to more than one processing facility. Thus, it would often be inaccurate and infeasible to attribute emissions from a gathering pipeline system to a particular processing facility. Indeed, it is simply impossible to lump these complex networks together with discrete processing facilities and production areas in a way that is logical and can be consistently implemented.

Furthermore, in many respects the same rationales that correctly led EPA to exclude petroleum and gas pipeline segments from Subpart W[238] apply with equal or greater force to gathering pipeline segments. Gathering pipelines are just as widely dispersed as transmission pipelines, are smaller in diameter than transmission pipelines, and operate at lower pressure than transmission pipelines. As with transmission pipelines, gathering pipelines are aggressively surveyed for leaks. For example, those gathering pipelines that are under the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA) are subject to federal regulations imposing regular inspections and repair requirements similar to those that apply to natural gas transmission pipelines.[239] There are also some 250,000 miles of gathering pipelines in service around the U.S.; if reporting entities were required to conduct component counts and carry out

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[236] Proposed 40 C.F.R. SECTION 98.230(a)(2), (a)(3).

[237] See 40 C.F.R. SECTION 60.630, 631 (defining "natural gas processing plant" to include the processing site, and only those portions of the field gas gathering system that are actually located on the processing site).] or NESHAPS. [Footnote 29: See 40 C.F.R. SECTION 63.761 (defining "facility" and "natural gas processing plant" for NESHAPS for Oil and Natural Gas Production Facilities).

[238] Proposed Subpart W, 75 Fed. Reg. at 18,616.

[239] See 49 C.F.R. SECTION 192.706, 711. EPA's TSD for the proposed Subpart W identifies PHMSA regulations as one reason why natural gas transmission pipeline segments should not be included in the Mandatory Reporting Rule.

optical leak detection surveys along the full length of these lines, the costs of Subpart W would escalate far beyond what EPA has estimated.

Kinder Morgan recommends that the proposed rule be revised to treat gathering compression and pipelines similarly to transmission compression and pipelines. Under this approach, gathering pipeline compressor and booster stations would be defined as a separate category of facility in proposed 40 C.F.R. SECTION 98.230, rather than being associated with production or processing facilities. Combustion, vented, and fugitive emissions from boosting and gathering stations that are above the 25,000 metric tons CO2-e per year threshold would be reported in the same manner as emissions from transmission compressor stations. Gathering pipeline segments, or at least those subject to PHMSA regulations, would be excluded from reporting. This approach would provide reporting of significant emissions from gathering pipeline systems, while eliminating the inconsistencies and inaccuracy that would surely result if gathering compression or pipelines were reported as part of the production or processing sectors.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1024-19
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

<u>Comment Excerpt Text:</u>
Clarification of Coverage of CO2 Transmission Pipelines. Our review of the rule suggests that EPA did not intend to require reporting of emissions from pipeline facilities that exclusively transport CO2. Nevertheless, Kinder Morgan is concerned that its CO2 transmission pipelines, which transport CO2 extracted from natural deposits to various EOR operations, could be considered part of an "EOR operation" for purposes of Subpart W,[240] and wishes to avoid confusion in the final rule. CO2 pipelines are, of course, distinct from natural gas transmission pipelines, and are not specifically mentioned as part of the petroleum and natural gas production sector in either the preamble to the proposed rule or the accompanying TSD.

As a policy matter, Kinder Morgan believes that CO2 transmission pipelines should be treated under Subpart W in a similar manner to natural gas transmission pipelines. Any facility along the pipeline that exceeds the 25,000 metric tons CO2-e per year reporting threshold would be subject to reporting, but the segments of pipe between facilities would be excluded from reporting. Excluding CO2 transmission pipeline segments from Subpart W would be appropriate, given that these pipelines present the same measurement issues that justify the exclusion of oil and natural gas pipelines from Subpart W (i.e., dispersed and relatively minor emissions). PHMSA regulations also require at least 26 surveys of surface conditions along pipeline rights-of-way

[240] See Proposed 40 C.F.R. SECTION 98.230(a)(2) (including "all EOR operations using CO2" in the definition of "onshore petroleum and natural gas production").

each year,[241] and Kinder Morgan takes the additional precautionary measure of continuously monitoring for leaks in its CO2 pipelines using a Supervisory Control and Data Acquisition (SCADA) system. Accordingly, Kinder Morgan requests that EPA clarify that CO2 transmission pipeline segments between facilities are excluded from reporting under Subpart W.

Response: Today's final rule does not include methodologies for emissions quantification or reporting of transmission gas pipelines between production, compression or processing facilities. This applies equally to CO2 pipelines. Today's final rule, Section 98.232 - GHGs to report, specifies what GHG emissions to report, and if an emission source is not listed in this section of the rule, it is not required to be reported. CO2 transmission pipelines, which transport CO2 extracted from natural deposits to various EOR operations, are not considered part of an "EOR operation" for purposes of Subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1024-3
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

<u>Comment Excerpt Text:</u>
EPA should revise its source category definitions to avoid confusion and uncertainty, especially with respect to multipurpose and co-located facilities. Using primary NAICS codes to classify facilities is recommended.

Response:
EPA does not agree to revise source categories or facility definitions for multipurpose or co-located facilities, or to include NAICS codes as part of facility definitions. Please see response to comment number EPA-HQ-OAR-2009-0923-1024-14 for more information.

14.1 ONSHORE PRODUCTION FACILITY DEFINITION

Comment Number: EPA-HQ-OAR-2009-0923-1014-2
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

<u>Comment Excerpt Text:</u>
B. Onshore Production: Basin-Level Definition of "Facility"
Under the proposed Subpart W, a single "onshore petroleum and natural gas production facility" means "all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists ["AAPG"] which is assigned a three-digit Geologic Province Code." 40 C.F.R. § 98.238 (emphasis supplied), 75 Fed. Reg. 18608, 18647 (April 12,2010). Significantly, "[w]here an operating entity holds more than one permit in a

[241] See 49 C.F.R. SECTION 195.412.

basin, then all onshore petroleum and natural gas production equipment relating to all permits in [that entity's] name in the basin is one onshore petroleum and natural gas production facility." Jd (emphasis supplied). In the Preamble to its proposal, USEPA explains that this approach was selected to capture "approximately 81 percent of emissions from onshore petroleum and natural gas production." 75 Fed. Reg. at 18615.

IOGA-WV strongly opposes this approach, which plainly (indeed, intentionally) disregards the most obvious and logical definition of a onshore production facility-the well pad, which may contain one or more wells and the attendant separation and storage facilities and associated equipment. Such an approach would be consistent with permitting practices for these facilities common under federal and state air programs. Proposed Subpart W, by contrast, artificially and dramatically broadens the definition of "facility" and effectively requires the industry sector to conduct additional monitoring and to adhere to a reporting threshold far below the 25,000 tpy CO_2e threshold that applies to other regulated industries. Obviously, this will impose substantially greater costs on the oil and gas industry as compared to other industry sectors, while producing only marginal environmental benefit.[242]

Response: EPA does not agree that the onshore facility definition is contrary to the CAA requirements. Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and the response to EPA-HQ-OAR-2009-0923-1044-1 for further details. EPA also disagrees with the commenter on the use of the well pad facility definition. Please see EPA-HQ-OAR-2009-0923-1005-3 for further details**.**

Comment Number: EPA-HQ-OAR-2009-0923-1014-6
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

Comment Excerpt Text:
In conclusion, IOGA-WV fundamentally disagrees with USEPA's conclusions in the Preamble to its proposed Subpart W that the GHG emissions from oil and gas production sector arc sufficient to warrant imposing burdensome monitoring and reporting requirements for individual wells. See 75 Fed. Reg. at 18613-15. IOGA-WV harbors serious concerns about USEPA's proposed adoption of a basin-level definition of an onshore production "facility" solely to capture small sources of GHG emissions that otherwise would fall well below the 25,000 tpy CO_2e applicability threshold that represents a balance of the environmental benefits of the rule with the burdens on small emitters. IOGA-WV believes that this approach would set a troubling precedent that, if taken to its logical conclusion and applied to other industries, could justify reporting for almost every small source of GHG emissions in the United States. Accordingly, IOGA-WV urges USEPA to adopt a well pad definition of facility that is reflective of actual operations. As noted in the preceding paragraph, while small emitters would be exempt from

[242] I IOGA-WV refers USEPA to the statistics set fOlih in IPAA's comments suggesting that onshore petroleum and natural gas production operations account for approximately 3.9% of the nation's GI--IG emissions.

reporting obligations under this approach, USEIA has capabilities that will allow it to make a reasonable estimate of those emissions attributable to onshore oil and gas production facilities.

Response: EPA disagrees with the commenter on the use of the well pad facility definition. Please see EPA-HQ-OAR-2009-0923-1005-3 for further details. EPA has also determined that only a small number of marginal operators in the country will be impacted by the rule. Please see response to EPA-HQ-OAR-2009-0923-1005-7 and Section 5.2 of the Economic Impact Analysis (EIA) for today's final rule found in docket (EPA-HQ-OAR-2009-0923)for further details.

Comment Number: EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
Facility Definitions

Industry and regulators currently have a very good understanding of what the term "facility" means in the O&G upstream sector. Company representatives as well as state regulatory agencies have been using this term to apply current CAA requirements across the country. Our recommendation is that we rely on the current actively used definition of facility that EPA change their proposed language to refer to a "threshold reporting area" or "roll-up area threshold" to define a geographical area to which a threshold can be applied that is made up of oil and gas upstream facilities. This would help alleviate industry concerns that the reporting rule definition of "facility" might impact perception of the CAA definition.

For example, 98.238 'Onshore petroleum and natural gas production facility' would read: 'Onshore petroleum and natural gas production reporting area means all petroleum or natural gas facilities and equipment associated with all petroleum or natural gas production under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined…'

The term reporting area could then be referred to in the definition of the source category; i.e., 98.230(2) 'Onshore petroleum and natural gas production': Onshore petroleum and natural gas production reporting area means all facilities associated with wells the production of petroleum or natural gas including but not limited to…

Response: EPA does not agree with the commenter. EPA has used the term "facility" consistently across the entire MRR to collect necessary GHG data. Also, all the requirements set forth in Subpart A refer to the facility. The use of any other term will lead to a disconnect within the MRR on the applicability of these overarching requirements. Furthermore, EPA does not see any benefit in using a term other than facility. Hence, in today's final rule, EPA has retained the usage of the term facility where appropriate. In today's final rule EPA has revised the term facility for the purposes of Subparts W and separated it from the Subpart A requirements with respect to natural gas distribution and onshore petroleum and natural gas production for clarity.

EPA has also ensured that there is no double counting of emissions [for monitoring, reporting and applicability threshold purposes] of co-located facilities in those source categories; please see response to EPA-HQ-OAR-2009-0923-1024-14 for further details.

Comment Number: EMAIL-0001-3 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
If Upstream Production Sites are Aggregated

If EPA rejects important financial burden and CAA definition of "facility" arguments and retains aggregation of upstream production sites, it should take reasonable steps to mitigate the adverse financial burden to industry, especially very small operators. This would include:

• Exempting small sites using well defined screening thresholds such as (1) natural gas production sites with only wellhead fugitive emissions and produced water storage tank emissions, (2) any natural gas production site with less than 3 MMSCFD of production and less than 1 BOPD condensate production, and (3) oil stripper wells producing less than 10 BOPD.

• Allowing the use of the API Compendium for calculations of emissions from upstream production sites. (See Item 3 below).

Response: EPA does not agree with the commenter on the exemption of small production sites based on their production level. Any such exclusion would necessitate defining the term "small site", which is not feasible for the same reason as defining a production facility site using aggregation of equipment; please see Section 4.c. of the TSD for further details. However, to reduce burden on the industry, EPA intends to develop a screening tool to assist in the determination of which facilities are required to report under today's final rule; please see Section II.F of the preamble to today's final rule for further details..

In addition, glycol dehydrators, onshore production storage tanks and blowdown vents below set equipment thresholds can report emissions using a population emission factor in today's final rule. However, those emission sources equal to or above the equipment threshold are required to estimate emissions using more rigorous methodologies. For further information please see the response to EPA-HQ-OAR-2009-0923-1011-39, EPA-HQ-OAR-2009-0923-1060-10, and EPA-HQ-OAR-2009-0923-1061-12 for glycol dehydrator, onshore production storage tanks and blowdown vents, respectively. In addition, external fuel combustion emissions from portable and stationary equipment, in onshore production and natural gas distribution, with heat input less than or equal to 5 mmBtu/hr do not have to be reported; however, reporting of equipment count by type is required. For further information, please see EPA-HQ-OAR-2009-0923-1024-23. Further details are available in Section II.F of the preamble to today's final rule.

EPA disagrees with only the use of the API Compendium emissions factors for calculations of emissions. However, EPA has used the same Gas Research Institute Study – *Methane Emissions from the Natural Gas Industry* that the API Compendium uses with some modifications to develop emissions factors for today's final rule. Please see rulemaking docket EPA-HQ-OAR-2009-0923 for memo "Equipment-Level Population Emission Factors for Onshore Production" and response to EPA-HQ-OAR-2009-0923-1151-130 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1004-14
Organization: Natural Gas Supply Association
Commenter: Patricia W. Jagtiani

Comment Excerpt Text:
EPA Must Clarify the Proposed Definitions of Industry Segments Subject to Subpart W
Like the American Petroleum Institute and other industry commenters in this docket, NGSA believes that the definitions of individual segments of the oil and gas industry in the proposed 40 C.F.R. 98.230(a) are confusing, inconsistent with industry practice, and would lead to double-counting of emissions from multipurpose or colocated facilities.

For example, it is not clear from the segment definitions whether a given gathering pipeline should be considered "part of" an onshore petroleum and natural gas production facility or a natural gas processing facility, because the definitions do not specify a physical boundary for either production or processing. Similarly, other units (such as gas dehydrators) could be considered part of more than one facility under the definitions proposed by EPA. Industry practice – and existing EPA regulations – differ substantially from the proposed Subpart W by clearly demarcating individual types of facilities with reference to a physical boundary, and by excluding gathering pipelines outside the facility "fence-line." Because the definitions in the proposed 40 C.F.R. 98.230(a) are ambiguous and difficult to apply, they would lead to inconsistent and potentially overlapping reports. These uncertainties also create a risk that NGSA members could be held liable for misreporting, even when making a good faith effort to properly apply the definitions in the rule.

In addition, the proposed definitions provide no guidance as to how facilities that serve or house multiple functions should be categorized. In the natural gas industry, it is common for a single site to include multiple facilities that perform different functions (production, processing, compression, etc.). Under the proposed Subpart W, it is not clear to which industry segment such facilities would correspond. Without further specifications on the treatment of such facilities, the proposed Subpart W could lead to inconsistent reports or inadvertent misreporting of emissions.

To resolve these issues, NGSA recommends that EPA:

Draw on existing regulatory definitions of facilities where possible (such as the descriptions provided in Subpart HH of EPA's NESHAP regulations for natural gas processing facilities, 40 C.F.R. 63.760). These definitions are well-understood by industry, and have proved workable in other regulatory contexts;

Create a separate facility category for gathering pipelines, consistent with the existing Department of Transportation / Pipeline and Hazardous Materials Safety Administration reporting;

Treat gathering/boosting compressor stations as individual facilities, consistent with current definition and treatment of facilities under the CAA; and

Allow reporting entities to use primary North American Industrial Classification System (NAICS) codes, and other appropriate and relevant data, to justify the classification of multi-purpose or co-located facilities.

Response: As explained in EPA-HQ-OAR-2009-0923-1044-1, EPA concluded that the definitions contained in today's final rule are appropriate to the purposes the MRR and Section 114. To apply NESHAP definitions or other definitions does not meet the purposes of the reporting rule. Such definitions are too restrictive and in application would exclude too many GHG emissions.

Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble. In the final rule EPA has revised the term facility in 98.238 for the purposes of subpart W, and separated it from the Subpart A requirements with respect to natural gas distribution and onshore petroleum and natural gas production for clarity. Please see the preamble Section II.D.
EPA agrees there is necessity for clear requirements for co-located facilities and multipurpose equipment. In today's final rule, EPA has provided further guidance on how reporters should deal with co-located facilities that serve multiple functions and also on equipment that serve multiple purposes. Please see the response to EPA-HQ-OAR-2009-0923-1024-14 for collocated facility requirements and equipment that serve multiple purposes.

EPA disagrees with the commenter on the use of NAICS code system. For further details, please see the response to EPA-HQ-OAR-2009-0923-1024-14.

Comment Number: EPA-HQ-OAR-2009-0923-1005-2
Organization: Independent Petroleum Association of America
Commenter: Lee Fuller

<u>Comment Excerpt Text:</u>
Facility Definition

Most notably, we believe that use of the CAA denies EPA the authority to create a definition of a facility that differs from that in the CAA. EPA proposes the following definition:

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

Under this definition, for example, all wells under common ownership along the Gulf Coast of Texas and Louisiana and deeply into the mainland of those states would be considered as one facility. This would be analogous to proposing that every McDonalds restaurant in the State of Texas should be considered as one facility because they have the same name and are franchised from a common source.

Nothing in the CAA suggests that EPA can define an onshore petroleum and natural gas production facility as broadly as it proposes. In reality, the only guidance provided to EPA in the CAA resides in Section 112(n)(4)(A) where it states:

… in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose …

Response: See response to Comment Number EPA-HQ-OAR-2009-0923-1044-1. Additionally, EPA finds the commenter's reference to 112(n)(4)(A) unpersuasive. The reference to aggregation contained therein relates exclusively to major source determinations for the purposes of the control of hazardous air pollutants and further expressly limits the provision to "…any purpose *under this section*….," namely CAA Section 112. As pointed out in previous responses to comments the reporting rule is not delimited by other CAA programs.

Furthermore, EPA is obligated to collect all relevant GHG emissions data from all the industrial sectors to inform future policy making, including onshore production of the oil and gas industry. On a national basis, GHG emissions from the oil and gas industry are second only to power plants. And within the oil and gas industry, the onshore petroleum and natural gas sector contributes over half of those total emissions. Hence, as the upstream oil and gas production sector contributes such a large portion of total U.S. greenhouse gas emissions, EPA has determined that it is necessary to collect an accurate amount of GHG emissions information from this segment. In developing today's final rule, EPA considered various options in collecting the information.

Corporate or company level reporting nationwide was an option EPA considered but did not pursue since it was substantially more burdensome for small businesses than a basin facility definition because companies are bigger in size than are facilities for the application of emissions thresholds, i.e. companies would end up adding up emissions from their multiple facilities, in this case basins.

EPA considered field level and wellhead level facility definitions as well. To meet the purposes of the MRR and to gather a reasonably significant amount of GHG emissions information from the sector using these facility definitions, would have required either drastically lowering or eliminating the 25,000 ton threshold altogether. Defining the source category on a field or wellhead basis would require “all-in” reporting of emissions to gather any meaningful amount of information such as with respect to those sources covered by Section 98.2(a)(1) of today’s final rule and would be substantially more burdensome than the basin-level definition because many more facilities would have to report. Therefore, EPA has determined that defining the facility at the basin level best manages the burden issue that the field level and wellhead level definitions raise. A basin level definition balances the cost to report with the coverage of emissions. For a wellpad level coverage of emissions see Section 5 of the TSD to today’s final rule for further details. For field level coverage and cost analysis see Section 5.1.4 of the EIA to today’s final rule.

Furthermore, only a limited number of small businesses will have to report under the basin level definitions; please see response to EPA-HQ-OAR-2009-0923-1005-7 and Section 5.2 of the EIA for further details. Conversely, a significant number of small businesses would potentially be impacted if a field level or wellhead level definition were adopted because facilities are smaller when using field level or wellhead level definition and no or lower than 25,000 metric tons CO_2e threshold. . In conclusion, EPA has the Congressional mandate to adequately collect meaningful information from all segments of the economy including onshore production and considers today’s final rule to be the most cost-effective way to collect that information.

Comment Number: EPA-HQ-OAR-2009-0923-1009-2
Organization: Xcel Energy Inc.
Commenter: Eldon Lindt

Comment Excerpt Text:
Facility Definition

Xcel Energy owns and operates natural gas systems that include production, processing, transmission, storage, and distribution. For Subpart NN compliance, the entire system was considered as an LDC distribution system because the pipeline distribution system operates under a single tariff with oversight by the state Public Utilities Commissions or the Federal Energy Regulatory Commission.

Reporting of CO2 emissions under Subpart NN will be straightforward and the resources for reporting can be identified and scheduled. However, the definition of a "facility" in Subpart W lacks clarity as it relates to the 25,000 mtCO2e applicability determination. The Preamble acknowledges this lack of clarity (pg. 18613), but does not provide much guidance concerning the relation to stationary combustion sources in Subpart C that are below the reporting threshold. Xcel Energy recommends that stationary combustion sources that are excluded because they are below 25,000 mtCO2e for Subpart C be excluded from Subpart W reporting.

Response: EPA does not agree with the commenter on the exclusion of combustion emissions sources that are not included in Subpart C. In today’s final rule, an LDC reporting to Subpart W shall include all combustion emissions, less combustion emissions from equipment equal to or below 5 mmBtu/hr rated heat input capacity, in the determination of threshold to report for Subpart W, i.e. 25,000 mtCO2e (a count by type of equipment at or below the 5 mmBtu/hr equipment threshold has to be reported). Furthermore, starting 2011, LDCs are required to use facility definition and monitoring methods for combustion emissions under Subpart W. Also, starting 2011 all LDCs shall report combustion emissions under Subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1011-2
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Preamble Section II.(C.) on page 18613.—El Paso requests the EPA to consider utilizing the term "reporting area" under the definition of the source category for Onshore Petroleum and Natural Gas Production.

Response: EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1011-24
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Proposed Rule Section 98.238 Definitions.—Onshore petroleum and natural gas production facilities should be renamed "reporting areas" for clarity and correctness.

Response: EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1011-53
Organization: El Paso Corporation
Commenter: Fiji George

Comment Excerpt Text:
Section 98.238 Definitions

Onshore petroleum and natural gas production facility

Consistent with our comments under Section II, we recommend the use of "facility" be replaced with "reporting area" as follows:

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

Response: EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1015-29
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
98.233(g)(ii)(C): Gas well venting during unconventional well completions and workovers. The term "producing field" in this subpart is not defined.

Response: EPA has defined the term field in today's final rule and a producing field simply means a field that has any production during the reporting period. Please see Section 98.238 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1015-9
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
It is unclear how facilities required to report under Subpart C by the standard definition of "facility" would also report under Subpart W. PAW requests clarification/removal of portable combustion equipment

Response: The EPA has made clarifications about any conflicts for combustion emissions between Subparts C and W. For further details, please see the response to EPA-HQ-OAR-2009-0923-1060-27.

Comment Number: EPA-HQ-OAR-2009-0923-1016-6
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:

EPA is proposing an expansive and novel definition of the term "facility" in this 2010 Proposal that would sweep in all the miles of gas mains and customer service lines, city gate stations, and (due to an unclear definition) potentially all customer meters across a state if they are within a distribution system served by a single LDC.

Response: EPA does not agree with the commenter. EPA has clarified the definition for LDCs in today's final rule, and has noted that customer meters are not required to be monitored. Please see Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1018-18
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
Onshore petroleum and natural gas production – CAPP believes the all inclusive nature of this definition adds confusion to the already complex and burdensome reporting requirements for the oil and gas sector and may introduce overlap with other facility definitions. Therefore, CAPP recommends EPA reframe the "onshore petroleum and natural gas production" definition ensuring no overlap occurs with other facility definitions and covers only key sources of interest to the EPA.

Onshore natural gas plant – CAPP believes there may be some overlap with the definition above and that the broad scope of the definition includes sources that are not typically rolled into the emissions at a gas plant as it includes the field gathering systems/out of plant fence line facilities. CAPP recommends modifying the definition to include only the sources that are normally associated with the physical gas plant then incorporate the other associated emissions into another source or into a pre-existing source such as "onshore natural gas transmission compression".

Onshore natural gas transmission compression – As this definition includes the equipment other than that typically associated with compression, CAPP recommends the EPA add the word "system" to the end of the sources: "Onshore natural gas transmission compression system".

Response: In today's final rule, EPA has clarified the boundary between onshore production and other segments in Subpart W. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

With regards to the facility definition for gas processing, in today's final rule EPA does not include gathering lines and boosting stations Please see Section II.F of the preamble to today's final rule and Topic 2: Aggregation of Gathering and Boosting Systems with Processing Facilities in Volume 9 of the Response to Comments for further details. The commenter does not provide sufficient details as to which sources not associated with a physical facility have been included in the rule or how they can be incorporated into transmission compression stations, as also why the word "system" should be added of the source category name for transmission segment, hence EPA does not have a response. However, the definitions for natural gas processing facilities and transmission compression stations have been developed considering the operational boundaries of the two segments and hence, in today's final rule EPA has retained these definitions.

Comment Number: EPA-HQ-OAR-2009-0923-1027-18
Organization: Offshore Operators Committee
Commenter: Allen Verret

<u>Comment Excerpt Text:</u>
92.238 Definitions: Offshore petroleum and natural gas production facility means each platform structure and all associated equipment as defined in paragraph (a)(1) of this section. All production equipment that is connected via causeways or walkways is (sic) one facility. Paragraph (a)(1) is assumed to be 98.230(a)(1), which states, "…offshore production includes secondary platform structures and storage tanks associated with the platform structure."

OOC Comment: The dual definitions in the rule need to be aligned with each other, and the definition in 92.230(a)(1) should also reference connection via causeways or walkways in its source definition. Does this mean the EPA wants us to include secondary platform structures with the facility (reporting entity) whether or not they are connected via causeways or walkways? Further clarity is needed on the definition of offshore petroleum and natural gas production facility considering these multiple definitions.

Response: In today's final rule EPA has consolidated the definitions. Please see Section 98.230 – Definition of the source category of today's final rule for further details. Also, EPA clarifies that any secondary structures or equipment connected to the main platform via walkways are considered to be a part of the main platform for the purposes of threshold determination and emissions reporting.

Comment Number: EPA-HQ-OAR-2009-0923-1029-2
Organization: Western Business Roundtable
Commenter: Holly Propst

<u>Comment Excerpt Text:</u>
The key issues in this proposed rulemaking revolve around getting the definitions right. EPA must define what constitutes the definition of a "facility" in the context of the nation's various petroleum and natural gas sectors.

Response: EPA does not agree with the commenter that facilities in the petroleum and natural gas sectors are not well defined. Please see Section 98.6 of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), for all segments of the petroleum and natural gas industry, except onshore production and LDCs that are defined in Sections 98.230 and 98.238 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1029-3
Organization: Western Business Roundtable
Commenter: Holly Propst

<u>Comment Excerpt Text:</u>
EPA’s Proposed Definition of “Facilities” is Functionally Inappropriate and Counter to CAA

“Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.”[243]

We are troubled by EPA’s expansive definition of “facilities,” when it comes to onshore petroleum and natural gas production. It appears that EPA is attempting to treat oil and gas production in the same way it is approaching electric power systems under another of its’ pending supplemental rules to the MRR.[244]

There, EPA is suggesting that all owners and operators of equipment in an “electrical system” be treated as a facility, for purposes of determining whether the threshold of 25,000 tons of emissions/year for hexafluoride and perfluorocarbons is met and reporting is required. Here, the agency seeks to apply the same approach to natural gas production facilities, arguing for basin, or at least field-level, reporting of GHG emissions. The problem: the two examples are an apple to orange comparison.

The electrical equipment being discussed under the other rule is all part of an integrated electrical system. Here, the situation is very different. The mere presence of onshore production facilities in the same basin is not enough to link facilities. Those wells are not part of an integrated system. Each well operates independently. They are more analogous to power generation stations. Such facilities may sit in the same region of the country. Specific entities may have ownership shares in more than one. Yet, the CAA treats each plant as an individual “facility.” In this way, oil and gas production facilities fit much more neatly into the CAA existing definitional structure.

Yet, the CAA itself contains a caveat when it comes to regulation of oil and gas facilities. Section 112 lays out definitions of “stationary sources” whose emissions are to be regulated by the Act. Important in this regard is the following language:

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[243] 75 Fed. Reg. 18608 at page 18614.

[244] 75 Fed. Reg. 18652, April 12, 2010.

"…emissions from any oil and gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil and gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this Section."[245]

Response: Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2.

Comment Number: EPA-HQ-OAR-2009-0923-1031-2
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
EPA should not adopt a Subpart W definition of facility that is inconsistent with the facility definition used in other Clean Air Act programs. Industry and regulators currently have a very good understanding of what the term "facility" means in the upstream and midstream sectors. Company representatives as well as state regulatory agencies have been using this term to apply current Clean Air Act ("CAA") requirements across the country. EPA should not introduce a new definition for purposes of this subpart. For the upstream sector, EPA should delete the reference to a facility and should instead propose language to refer to a "threshold reporting area" or "roll-up area threshold" to define a geographical area to which a threshold can be applied that is made up of oil and gas upstream facilities. By doing so, EPA would minimize the confusion and regulatory uncertainty that might ensue should EPA finalize the rule as proposed.

For example, proposed section 98.238 'Onshore petroleum and natural gas production facility' would be revised to read: 'Onshore petroleum and natural gas production reporting area means all petroleum or natural gas facilities and equipment associated with all petroleum or natural gas production under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined….'

The term reporting area could then be referred to in the definition of the source category; i.e., 98.230(2) 'Onshore petroleum and natural gas production': Onshore petroleum and natural gas production reporting area means all facilities associated with the production of petroleum or natural gas including but not limited to….'

[245] The Clean Air Act, Section 112(n)4)(A).

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term “reporting area” instead of “facility”. For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1040-11
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
98.230(a)(2): The Onshore petroleum and natural gas production definition includes well drilling, completion, and workover equipment. As explained in section 3 above, reporting should not be required for well drilling, completion. and workover. Similarly, as explained in Section 4, in cases where the well site operator contracts these tasks to a third-party company, the well site operator does not own or operate the well drilling, completion, and workover equipment. When the well site operator does not own the equipment or control the operation or maintenance of the equipment, it is not appropriate to require reporting and compliance tasks of the well site operator because they do not participate in engine maintenance or the collection of fuel use data. All other CAA programs establish applicability based on whether a party owns and operates a source because it is not feasible for a person lacking control of a source's day-to-day operation to collect the required information or monitor the source's usage.

Response: EPA does not agree with the commenter. For further details, please see the response to EPA-HQ-OAR-2009-0923-1031-21. EPA does not agree that reporters should not be required to report emissions from drilling, completion, and workover operations. See response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1040-3
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
EPA should not adopt a Subpart W definition of facility that is inconsistent with the facility definition used in other Clean Air Act programs.
Industry and regulators currently have a very good understanding of what the term "facility" means in the oil and gas upstream sector. Company representatives as well as state regulatory agencies have been using this tern to apply current CAA requirements across the country. Our recommendation is that we rely on the current actively used definition of facility and that EPA change their proposed language to refer to a "threshold reporting area" or "roll-up area threshold" to define a geographical area to which a threshold can be applied that is made up of oil and gas upstream facilities. This would help alleviate industry concerns that the reporting rule definition of "facility" might impact perception of the CAA definition.

For example, 98.238 'Onshore petroleum and natural gas production facility' would read: 'Onshore petroleum and natural gas production reporting area means all petroleum or natural gas facilities and equipment associated with all petroleum or natural gas production under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined....'
The term reporting area could then be referred to in the definition of the source category; i.e., 98.230(2) 'Onshore petroleum and natural gas production': Onshore petroleum and natural gas production reporting area means all facilities associated with the production of petroleum or natural gas including but not limited to ....'

Response: EPA does not agree with the commenter's suggestion about facility definitions. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term "reporting area" or other such terms instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1041-5
Organization: Spectra Energy Corp
Commenter: Brianne Metzger-Doran

<u>Comment Excerpt Text:</u>
The Definition of Onshore Natural Gas Processing Plant is Overbroad to the Extent it Includes Booster Stations Where No Natural Gas Processing is Actually Performed

The proposed definition of "Onshore Natural Gas Processing Plants" in § 98.230(3) is overly broad and confusing to the extent the definition includes booster stations where no natural gas processing actually occurs. Spectra Energy operates a number of booster stations that receive pipeline quality natural gas (that is, gas that requires no processing) and pump it directly into transmission pipelines. These facilities are distinct from processing plants designed for separation and recovery, and from field gathering and boosting stations that feed gas processing plants. The second to last sentence of § 98.230(3) states:

Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities.

Gathering and booster stations that receive and move pipeline quality gas into transmission or distribution, where no additional processing occurs, are functionally equivalent to natural gas transmission compression stations, and should be categorized accordingly for purposes of Subpart W. Spectra Energy strongly recommends that the EPA eliminate the above quoted sentence from § 98.230(3), and/or insert language in § 98.230(4) clarifying that a booster station that receives and moves pipeline quality natural gas without performing any natural gas processing is classified as "onshore natural gas transmission compression."

Response: Today's final rule does not include gathering lines and boosting stations. For further clarification, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1042-5
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

Comment Excerpt Text:
Gas Well (EPA does not define)

ConocoPhillips Comment:

Add, Gas Well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

• EPA proposed definition: Unconventional Well means a gas well in producing fields that employ hydraulic fracturing to enhance gas production volumes.

ConocoPhillips Comment:

A time element is not associated with this definition and this makes it subject to misapplication. For example, if a gas well was fractured one or two years ago but is worked without being fractured in a subsequent year, it could be placed into the unconventional well category for the reporting year – though that does not seem to be EPA's purpose. We request that EPA modify the definition to:

Unconventional Well means a gas well in producing fields that is undergoing hydraulic fracturing to enhance gas production volumes.

Response: EPA agrees with the commenter. In today's final rule, EPA has provided a definition for natural gas wells. Also, with regards to well completions and workovers, EPA has revised the source category names that now distinguish the source based on whether or not the completion involved hydraulic fracturing or not in the reporting year. This will avoid any confusion relating to the timing of when the hydraulic fracturing was conducted.

Comment Number: EPA-HQ-OAR-2009-0923-1058-1
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
In regards to the proposal to require reporting of greenhouse gas (GHG) emissions including

petroleum and natural gas systems, COGA's main concern is the restrictive and inconsistent definition of "facility" as previous defined in previous rules and established in the Clean Air Act.

Response: Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2.

Comment Number: EPA-HQ-OAR-2009-0923-1058-14
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
Usage of "facility" for natural gas distribution, offshore petroleum and natural gas production and onshore petroleum and natural gas production.

Incorporating the term "facility" in this definition adds confusion to the term currently well understood by industry and regulating bodies. The Clean Air Act as well as § 98.6 of this Part define a facility as "…any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties…" Our recommendation is to replace "facility" with "reporting unit" or "area" which would encompass the applicable facilities encompassed in the producing basin.

Response: EPA does not agree with the commenter's suggestion about facility definitions. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1064-1
Organization: Vorys, Stater Seymour and Pease LLP
Commenter: Gregory D. Russell

Comment Excerpt Text:
While the boundaries of overall production operations can vary widely and may not be easily characterized, if greenhouse gas emissions monitoring and reporting are going to be required of producers - which the Association continues to oppose, particularly for small producers - the most sensible facility definition is the one proposed by IPAA, i.e., defining the well pad as the production facility. This tracks the nature of the producer's operations and is consistent with the definition applied to other industries under the CAA, in addition to being the typical permitting unit under CAA regulations.

Response: EPA does not agree with the commenter. Please see responses to EPA-HQ-OAR-2009-0923-1005-6 and EPA-HQ-OAR-2009-0923-1005-2 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1100-4
Organization: Linn Energy
Commenter: Paul M. Espenan

Comment Excerpt Text:
Comment 2: The EPA Subpart W definition of facility (i.e. basin) is inconsistent with the well-established facility definition currently used in other Clean Air Act programs. This definition causes confusion and results in a much larger reporting burden for industry than anticipated by EPA in its impact analysis.

Response: Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2.

Comment Number: EPA-HQ-OAR-2009-0923-1151-12
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Alternatively, EPA Must Clarify That Emissions Should Be Reported by the Operator of a Given Well

Under the final GHG MRR, the "designated representative" of a "facility"[246] is responsible for certifying, signing, and submitting GHG emissions reports. Significantly, the proposed definitions of "facility" for onshore and offshore petroleum and natural gas production, and for natural gas distribution, differ from the definition of "facility" applied in the remainder of the Mandatory Reporting Rule. This distinction is particularly key for the onshore petroleum and natural gas production sector. In a single geologic basin, there may be thousands of individual sources, owned and operated by a variety of entities and contractors. Furthermore, this segment is typified by complex operational, infrastructure, commercial and ownership arrangements, and the fact that many of the operators are small companies without significant resources, knowledge, and staff, making this distinction particularly critical. Likely due to these issues, EPA has expanded the definition of an onshore petroleum and natural gas production "facility" to include all equipment associated with production and distribution under common ownership or control and located in a single hydrocarbon basin:

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[246] A facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. 40 C.F.R. Section 98.6.

"all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin . . . Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility."

75 Fed. Reg. at 18,647. Under this definition of facility, the reporting entity for an onshore petroleum and natural gas production facility is

"the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state, who operates onshore petroleum and natural gas production wells and controls by means of ownership (including leased and rented) and operation (including contracted) stationary and portable (as defined in this Subpart) equipment located on all well pads within a single hydrocarbon basin." Id. at 18,614.

API suggests that EPA clarify the obligation of operating entities for onshore petroleum and natural gas production facilities to report emissions from contractors operating within a geologic basin. Specifically, EPA should sharpen the distinction between contractors that are acting under the direction of an operating entity—who generate emissions that arguably must be reported by the operating entity—versus contractors that are not under the operating entity's control. EPA should make clear that the operating entity is not responsible for reporting contractor emissions in situations where it does not operate a given well location and therefore does not necessarily have reasonable access to emissions data.

Response: Please see the responses to EPA-HQ-OAR-2009-0923-1031-21 and EPA-HQ-OAR-2009-0923-1170-7.

Comment Number: EPA-HQ-OAR-2009-0923-1151-2
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>**Comment Excerpt Text:**</u>
Onshore Petroleum and Natural Gas Production Facility Definition

Although API believes that grouping owner/operator's GHG emissions at the American Association of Petroleum Geologists (AAPG) basin level may be useful for threshold determination and reporting purposes under this rule, we do not believe it is beneficial from the standpoint of balancing burden with quality emissions data. EPA's focus on millions of individual sites and equipment is adding complexity to the effort of compliance with the rule without necessarily increasing the data quality. API believes the issues can be resolved by allowing owners/operators to group together similar operations and sources for emissions calculation rather than forcing emissions estimation on every source within a basin.

Most basins are complex and can have several different types of production, multiple dissimilar reservoirs, with broadly differing fluid compositions and make-up, and different equipment and operational practices driven by the reservoir characteristics and type of production. This complexity poses a real challenge to developing emissions estimation methods which appropriately balance burden and quality. Allowing the grouping of fields (in EIA's field list) within a basin based on common production characteristics will achieve EPA's articulated goal in the proposed rule of reducing burden without compromising data quality. These characteristics would be the same (or groups of similar) producing reservoirs, similar well depths and well-bore configurations, similar pressure and temperature ranges, similar fluid compositions and Gas-to-Oil Ratios (GOR's), similar production arrangements and surface equipment, and similar operational characteristics and practices. For example, in the state of Wyoming a "similar site" is defined for hydrocarbon sampling based on the same reservoir and production equipment with similar characteristics (±25 psig), allowing compositional analysis to be determined from a minimum of 5 wells and an updated analyses conducted every 3 years.

Each covered operator in a basin would select these groupings of fields based on their particular operations and portfolio, using the above characteristics, and fully describe them in their monitoring plan along with their rational for a particular grouping. This "Sub-basin entity" would enable the development of activity or emission factors and approaches based on the parameters that affect the amount and type of emissions from a particular Sub-basin area. Although the proposed rule does enable this approach in limited instances and source types, the approach still needs to be broadly expanded.

In our comments regarding each source type, API will detail how these activity/emission factors and approaches may be developed for a particular source type within a Sub-basin entity grouping of similar fields. Examples of how these Sub-basin entities might be demonstrated, could be discussed further with EPA.

i. "Facility" Terminology

API concurs with EPA's statement in the FAQs to proposed Subpart W (Subpart W FAQ, March 2010) that "the facility definitions proposed in this rule do not impact requirements under other EPA regulations, for example, New Source Review (NSR)". The structure of the Clean Air Act (CAA) supports EPA's statement and in fact requires this result. EPA relies on its authority under Section 114 of the CAA as the basis for the proposed GHG reporting rule—authority which is completely independent from EPA's authority for other CAA programs, for example, from EPA's CAA NSR authority, including CAA Sections 160-169 and 171-193. As such, EPA regulations promulgated under these distinct provisions in Section 114 cannot and should not impact the other CAA programs and vice versa. Therefore, EPA's definition of "facility" for purposes of the proposed Subpart W in no way impacts the "facility" definition for similar sources under the NSR program or other existing CAA programs.

While we appreciate that EPA has clarified that the proposed definition of facility in this rule does not impact other EPA regulations, we do not feel that the FAQ response provides enough of a backstop against a slow creep in the definition under other CAA regulatory programs. EPA's statement should be included in the regulation itself.

Furthermore, API suggests an alterative term that is not already defined elsewhere in the CAA be proposed (in place of “facility”) for the geological basin grouping of emissions. We propose the term “Basin entity” be used in place of “facility” for all discussions related to the geologic basin grouping of emissions that are made up of distributed sources either at the field level or for sources that are grouped across production fields. We propose the term “Sub-basin entity” for describing the grouping of fields with similar characteristics within the basin. API also recommends that the term “facility” only be used when referring to a traditional facility (consistent with CAA terminology), such as an oil and gas processing plant, to avoid confusion.

API Requests:

- EPA should enable the grouping of similar named fields within a basin into a “Sub-basin entity” for emissions determination based on the characteristics outlined above.
- EPA should use the term “Basin entity” when referring to the roll-up of “Sub-basin entities” for assessing onshore oil and gas production operations against the reporting threshold.
- EPA should add the statement that “the facility definitions in this rule do not impact requirements under other EPA regulations, for example, New Source Review (NSR)” to the regulation itself.

Response: EPA disagrees with the commenter on the grouping of sub-basin entities. For further clarification, please see the response EPA-HQ-OAR-2009-0923-1305-46.

As regards impact of this rule on other EPA regulations, please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1155-16
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

Comment Excerpt Text:
Portable Equipment Consistent with WCI’s comments to EPA, we also support the inclusion of Portable Equipment in the Subpart W petroleum and natural gas production definition. We agree with WCI that Portable Equipment should be defined as all portable non-self propelled equipment used in the petroleum and natural gas production industry. We agree the definition should not be limited to equipment stationed at a wellhead for more than 30 days. Portable Equipment (e.g. drilling rigs, workover rigs, construction equipment) can generate substantial emissions in periods of less than 30 days. Subpart W should not create an incentive for Operators to stage Portable Equipment at a location for less than 30 days, to thereby avoid Portable Equipment GHG emissions reporting. If this occurred, it would severely underestimate the actual emissions being generated.

Response: EPA agrees with the commenter. In today’s final rule, EPA has removed the 30 day at location requirement for portable equipment emissions monitoring. Please see the response to EPA-HQ-OAR-2009-0923-1170-7 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1167-1
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

__**Comment Excerpt Text:**__

The concept of "Reporting Area" should replace the proposed definition of "onshore petroleum and natural gas production facility." The Subpart W definition of facility for onshore petroleum and natural gas production is inconsistent with the facility definition for other CAA programs and will cause undo complexity for companies managing compliance with numerous air regulations. Designation of "reporting areas" for this Subpart W will establish the source category that EPA desires without using an overly board definition of "facility" that will result in confusion, uncertainty and practical application problems. The Section 98.6 definition of facility should be retained and apply to onshore petroleum and natural gas production.

The proposed term "onshore petroleum and natural gas production facility" (proposed 40 C.F.R. Section 98.238) as currently drafted is overly-broad and will create legal and practical application uncertainty. First, the term in section 98.238 is overtly inconsistent with the definition of "facility" in 98.6, and the definition of "facility" as used under other Clean Air Act regulatory programs. The EPA's statement on its web posting (Subpart W FAQ, March 2010) states that ". . . the facility definitions proposed in this rule do no impact requirements under other EPA regulation, for example, New Source Review (NSR)." Noble appreciates that the EPA will limit this novel facility definition to reporting under Subpart W. However, this deviation from historical regulatory precedent and delineation of source boundaries and revised application of the term "facility" for this one GHG regulatory scheme will create undue confusion not only by the regulated community, but also among regulators. It further subjects both the regulated community and the EPA to litigation risk regarding the meaning and use of this term. Second, Subpart W appears to be the only subpart that imposes an expansive definition of "facility." All other subparts related to other source categories adhere to the term "facility" as defined in 40 C.F.R. Section 98.6.

The objective of the proposed rule is to establish reporting requirements for facilities that emit greenhouse gases as contemplated by 40 C.F.R. Section 98.1(a). This objective can be achieved for source categories subject to Subpart W without complicating the use of the term facility. To this end, Noble recommends the term "onshore petroleum and natural gas production facility" in Section 98.238 be deleted in its entirety and replaced with a "reporting area". This concept of a "reporting area" is already being utilized by EPA in its currently proposed definition of "onshore petroleum and natural gas production facility," however it is used in a way that does not distinguish it from a "facility". *More clarity and regulatory certainty is provided by clearly distinguishing "reporting area" from "facility" in this regulatory context.* . Therefore, Noble recommends that the definition of "onshore petroleum and natural gas production facility" in Section 98.238 be amended and replaced with the following proposed definition of "onshore petroleum and natural gas production reporting area:"

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

This proposed definition of "reporting area" clearly defines the geographic reporting boundaries for an owner or operator of onshore petroleum and natural gas production sources which are subject to the reporting requirements without creating confusion and uncertainty regarding the term "facility" or unintentionally expanding the meaning of "facility."

Response: EPA does not agree with the commenter on the inconsistency of facility definition not being compatible with the CAA. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923). As regards impact of this rule on other EPA regulations, please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1167-3
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Section 98.2 Who must report?

An owner or operator of onshore petroleum and natural gas production facilities that have total emissions from all facilities located within an onshore petroleum and natural gas production reporting area (as defined in Section 98.238) of 25,000 metric tons CO_2e or more per year.

If EPA does not accept Noble's recommended revisions to the Proposed Rule's definition of offshore petroleum and natural gas production facility, Noble believes it is imperative that EPA include language in the Rule to state that the Rule's definition of offshore petroleum and natural gas production facility will not be applied elsewhere in the CAA and will not impact other EPA regulations.

Note to reader, in the comments that follow the familiar "facility" is often retained for consistency with the Proposed Rule language. As discussed above, "facility" would be replaced by "reporting area" in the final rule.

Response: EPA does not agree with the commenter with regards to restrictions on the use of definition from Subpart W in other EPA regulations; please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1167-42
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Onshore petroleum and natural gas production owner or operator means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates an onshore petroleum and/or natural gas production ~~facility~~ (as described in ~~Section 98.230(b)(2)~~ Section 98.230(a)(2)). Where more than one entity ~~are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility~~ holds legal or equitable title to or control over a source in section 98.230(a)(2), the entity exercising the greatest operational control over the source category shall be deemed the owner or operator designed to report all emissions. For all purposes of Subpart W, onshore petroleum and natural gas production owner or operator excludes any other person or entity who has legal or equitable title to, has a leasehold interest in, or control of a facility or supplier or petroleum and natural gas well or source, including but not limited to royalty interest owners and non-operators."

Noble recommends that the language above, or similar text, be incorporated into the definition for onshore petroleum and natural gas production owner or operator in Section 98.6.

Response: EPA does not agree with the commenter. EPA will not constrain owners or operators in choosing who shall be the designated representative. The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final rule. Please see the responses to EPA-HQ-OAR-2009-0923-1024-16 and EPA-HQ-OAR-2009-0923-1031-21.

Comment Number: EPA-HQ-OAR-2009-0923-1167-44
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
The definition of "onshore petroleum and natural gas production owner or operator" should be revised to clarify that royalty owners and non-operating interest owners be excluded from the revised definition.

Response: The issue highlighted by the commenter has already been dealt with in the final MRR. Please see the preamble Section V.B.1 response on the Certification Statement of the Final MRR (October 2009), and rule Sections 98.4(b) and 98.4(i)(4)(iv) of the Final MRR.

Comment Number: EPA-HQ-OAR-2009-0923-1167-47
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Section 98.232 lists eight Subpart W industry segments [i.e. (b) through (i)] and the emission sources to report for each segment. For onshore petroleum and natural gas production, 21 primary sources are identified. Noble supports EPA's intent to limit reporting to segment-specific sources listed in Section 98.232. However, additional clarifying rule text is needed to avoid unnecessary implementation questions.

Onshore petroleum and natural gas production and processing operations include an array of processes and equipment / source types, ownership, leasing, and arrangements that significantly complicate clear facility and source applicability delineation. For example, a central gathering facility that has liquid stabilization may have sources from onshore petroleum and natural gas production Section 98.232 (c), and also onshore natural gas processing Section 98.232 (d). In this example, the lack of clear segment delineation from the multi-use facility unnecessarily complicates rule interpretation, implementation and compliance. Noble understands that a facility is only required to report emissions from the sources listed in the applicable Section 98.232 subsection; that is, the source list is specifically defined and limited to those sources in the Section 98.232 subsection for that segment.

Noble further understands that the applicable segment is based on the primary facility function. The 21 emission sources in Section 98.232(c) are to be reported under Subpart W for onshore petroleum and natural gas production. If other emission sources applicable to another segment (i.e. beyond the 21 onshore production sources) are at a production facility (e.g., a blowdown vent stack), emissions reporting for that source is not required.

Further clarification directed toward accurately defined segment definition and source applicability is needed for unambiguous identification of over riding section of the rule. Noble does not advocate reporting under multiple segments and instead advocates a primary facility reporting segment and source requirements. These clarifications are required to ensure rule implementation and compliance issues do not arise.

Response: In today's final rule EPA has provided clear requirements on reporting of emissions from co-located facilities and multiple use equipment. For further details, please see the response to EPA-HQ-OAR-2009-0923-1024-14. EPA has also reviewed and clarified as necessary all source category definitions and concluded that today's final rule should mitigate any concerns regarding ambiguity in definitions. Today's final rule defines the processing industry segment as the processing facility and does not include gathering lines and boosting stations. For further clarification, please see Section II.F of the preamble to today's final rule. Hence the overlap issue between onshore production and onshore natural gas processing does not apply anymore. For further clarification on gathering and boosting systems, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1170-1
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:

The definition of "facility" in the proposed Subpart W, upon which an operator would assess applicability of the 25,000 tons/year greenhouse gas ("GHG") threshold, includes all petroleum and natural gas equipment associated with all production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin. This definition is inconsistent with the definition of "facility" in other subparts of this rule, and therefore will result in an inequitable application of the rule. Also, it is inconsistent with the "facility" definition in the Clean Air Act ("CAA"). The preamble states that the information gathered by the implementation of this rule would inform and guide EPA in carrying out a wide variety of CAA provisions. It is understood that EPA will use the GHG inventory data to define future permitting and compliance programs. For this reason, we do not agree with redefining the term "facility" in this Subpart. If EPA uses the information in this program for other CAA programs, it must be collected in a manner that is consistent with how it will be applied in those programs.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2.

Comment Number: EPA-HQ-OAR-2009-0923-1170-2
Organization: Pioneer
Commenter: Gretchen Kern

Comment Excerpt Text:
Building, structure, facility or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (ie: which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

In accordance with this definition and multiple case-by-case aggregation determinations made by the EPA and the states, most production operations across a single hydrocarbon basin cannot be aggregated into one facility. If these production operations are not aggregated by basin, each facility or well site must be individually assessed for applicability to the future permitting and compliance programs. At this time, EPA has proposed an applicability threshold of 25,000 metric tons CO_2e/year for permitting and that threshold will apply at the facility level, as "facility" is currently defined in the Clean Air Act. If the purpose of this rule is to inform future rule-making, there is no benefit to collecting information for an aggregation of many small facilities that will not be subject to future rules. We therefore request that EPA modify this "facility" definition to be consistent with the "facility" definition employed in other CAA programs.

Based on this basin-wide "facility" definition, we anticipate that essentially all of Pioneer's asset areas in the U.S. would be subject to reporting under Subpart W. This basin-wide application would aggregate many insignificant emissions sources together and is not reasonable from a cost/benefit analysis of supplying representative, useful, high quality emissions data. The time and cost burden of just collecting this data would be massive, as outlined in the points below. In order to achieve a lower burden and more representative, high quality emissions data, Pioneer agrees with API's recommended approach that would allow operators the flexibility to report at the basin level while also allowing them to identify rational "reporting units" within a basin (that have similar operations, equipment, fluid properties, and physical properties).

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2.

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EPA disagrees with the commenter on the grouping of sub-basin entities. For further clarification, please see the response EPA-HQ-OAR-2009-0923-1305-46.

Comment Number: EPA-HQ-OAR-2009-0923-1173-11
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

<u>Comment Excerpt Text:</u>
Definition of "Facility" for Onshore Petroleum and Natural Gas Production

"EPA seeks comments on our decision to propose the basin level approach and whether there would be advantages to requiring reporting at the field level instead. " (75 FR 18615)

Resolute Comments:

Resolute opposes EPA's proposed definition of "Onshore petroleum and natural gas production facility," as it is inconsistent with other regulatory programs under the CAA. Industry and regulators currently have a very good understanding of what the term "facility" means in the oil and natural gas upstream sector, as they have been using this term since it was promulgated in

1980 with the Prevention of Significant Deterioration ("PSD") regulations. Resolute recommends that EPA use this well-established definition of facility instead of introducing an entirely new definition in Proposed Subpart W. EPA should alter the proposed language in Proposed Subpart W to maintain the traditional definition of "facility" but then refer to a "threshold reporting area" or something similar to define a geographical area (e.g., basin-wide or field-wide). An owner/operator would then need to calculate the greenhouse gas emissions from each of its onshore petroleum and natural gas production facilities within the threshold reporting area to determine if it exceeds the reporting threshold and is subject to the reporting requirements. This would help alleviate industry concerns about how the Proposed Subpart W definition of "facility" might impact this same term as defined in other CAA programs, in particular New Source Review.

As an example, Resolute would suggest that EPA make the following changes to Proposed Subpart W §§ 98.238 and 98.230(2):

§ 98.238: Onshore petroleum and natural gas production threshold reporting area means all petroleum or natural gas facilities and equipment associated with all petroleum or natural gas production under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined ....

§ 98.230(2): Onshore petroleum and natural gas production: Onshore petroleum and natural gas production equipment threshold reporting area means all structures facilities associated with the production of petroleum or natural gas including but not limited to all structures associated with wells ....

In the alternative, if EP A decides to proceed with the definition of "Onshore petroleum and natural gas production facility" as proposed, Resolute requests that EPA expressly state that "the facility definitions proposed in this rule do not impact requirements under other EPA regulations, for example New Source Review (NSR)" in the rule itself, as it did in the FAQ for Proposed Subpart W, or at a minimum provide a similar statement in the preamble to the final rule when it is published in the Federal Register.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term “threshold reporting area” instead of “facility”. For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923). As regards impact of this rule on other EPA regulations, please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1173-3
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
EP A should use a definition of "facility" for onshore oil and natural gas production that is consistent with other CAA regulatory programs, but provide for basin-level reporting by rolling up facility emissions into a basin-wide "reporting area."

Response: EPA does not agree with the use of the term "reporting area" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) and response to EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1174-5
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

Comment Excerpt Text:
Devon does not support the proposed "onshore petroleum and natural gas production facility" definition for the following reasons.

First, aggregation of upstream production sites imposes a disproportionate burden on our industry by requiring data collection, recordkeeping, and reporting for hundreds of thousands of dispersed production sites.

Second, EPA's proposal to aggregate all E&P wells within a basin as a single "onshore petroleum and natural gas production facility" is inconsistent with existing Clean Air Act (CAA) regulations and incongruous with ownership and control of affected operations.

Third, we are concerned that EPA's definition of "onshore petroleum and natural gas production facility" could potentially impact the "facility" definition for similar sources under other CAA regulatory programs. Although we agree with EPA's statement in the Frequently Asked Questions to proposed Subpart W that "the facility definitions proposed in this rule do not impact requirements under other EPA regulations, for example, New Source Review (NSR)", we believe it is imperative that this statement is included in the regulation itself.

Response: Without more than a broad comment that the basin-level definition of facility with respect to onshore petroleum or natural gas production imposes a disproportionate burden, it is difficult for EPA to respond in detail. Please see Volume 10 of responses to comment and EIA to today's final rule for details on how EPA has determined that the burden to report to the rule is reasonable.

EPA does not agree with the commenter on inconsistencies with the CAA. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1. Likewise, the broad statement that the proposal to aggregate all E&P wells within a basin is inconsistent with the CAA and regulations without more precise explanation, makes it difficult for EPA to respond. Generally, however, as explained above and in the preamble to the proposed rule (75 FR 18608) and accompanying Technical Support Document (TSD) found in docket (EPA-HQ-OAR-2009-0923-0027), because of the unique nature of petroleum and natural gas production facilities, it is reasonable and appropriate to define the facility based on the hydrogeologic basin and equipment owned or operated by the entity holding permits in that basin. The physical boundaries of a production or distribution owner or operator's holdings are not discrete such as for other industry segments. And while the PSD and NSR programs might apply to stationary sources as defined by regulation, the scope of CAA Section 114 is not so limited; nor is EPA regulating greenhouse gases under the MRR. The scope of the rule and the authority on which is based is not limited to regulated sources and to graft a source definition from other regulatory programs on the rule is neither appropriate nor reasonable. Further, as the owner or operator is only required to report information from its own wells or operations in the basin, and as the owner or operator is defined in today's final rule as the person or entity who holds the drilling or operating permit (or otherwise who pays the state or federal business income taxes for the operation), EPA disagrees that any incongruity with ownership or control exists.

The definition of facility with respect to onshore petroleum or natural gas production in today's final rule expressly states it is defined, "for purposes of this subpart and subpart A." Further, Section 98.238 of today's final rule states that "[e]xcept as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part…." These provisions separately stated, and particularly when read together, make it clear that the facility definition is discrete to Subpart W. EPA considers this language to sufficiently address limitation of the definition and its relationship to other programs.

Comment Number: EPA-HQ-OAR-2009-0923-1198-1
Organization: West Virginia Oil and Natural Gas Association
Commenter: Nicholas DeMarco

Comment Excerpt Text:
As drafted, Subpart W would essentially require the reporting of GHG emissions from every source, no matter the size, due to the definition of "facility".

Response: In today's final rule, EPA has provided equipment thresholds that require the use of simple emissions factors for equipment below the thresholds. This will avoid unnecessary burden on smaller sources while at the same time gather necessary data to inform policy. Please see Section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1198-8
Organization: West Virginia Oil and Natural Gas Association
Commenter: Nicholas DeMarco

Comment Excerpt Text:
Defining "Facility"

One of the most concerning aspects of this proposal is the EPA's various proposed definitions of "facility". EPA has proposed numerous definitions depending on the industry sector. Not only does this cause confusion in determining applicability, the definitions would impose significant burden on the industry as a whole. We agree with AXPC that EPA rely on the current definition of "facility" which has been used by both industry and state agencies regularly. We are concerned with the proposal to redefine the universe of facilities within the natural gas sector for purposes of this rule and we agree with the comments submitted on behalf of GPA and AXPC. We are particularly concerned with the proposal to aggregate emissions at the basin level and with the proposed definition of natural gas processing facility, as set forth in more detail below.

Response: EPA does not agree with the commenter. EPA has chosen the onshore definition to collect necessary information to inform policy. Please see response to EPA-HQ-OAR-2009-0923-1044-1 for further details. EPA has also revised onshore gas processing definition to clarify any overlap issues with onshore production; please see response to EPA-HQ-OAR-2009-0923-1080-45 for further details. Finally, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1297-3
Organization: Southern Ute Growth Fund
Commenter: Lynn Woomer

<u>Comment Excerpt Text:</u>
As mentioned above, the SUGF does not agree, in particular, with the Subpart W definition of facility. Primarily, the redefining of the term facility in this proposal is not consistent with the way the term is defined and utilized in numerous Clean Air Act (CAA) Programs. As proposed, the definition of facility will require aggregation of numerous production sites. It is for this reason, and the perception that this may create when used in other CAA programs that the SUGF disagrees.

If the Greenhouse Gas (GHG) emissions inventory data is to be utilized as understood (i.e. to define future permitting and compliance programs); then data should be collected in a manner consistent with how it will be applied, as historically completed with well established CAA programs. Therefore, the SUGF recommends EPA utilize a different term to describe the proposed reporting area(s), such as, basin and/or field "reporting area".

Response: Please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

EPA does not agree with the use of the term “reporting area” instead of “facility”. For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1298-23
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Section 98.230(a)(2): The Onshore petroleum and natural gas production definition includes well drilling, completion, and workover equipment. In cases where the well site operator contracts these tasks to a third-party company, the well site operator does not own or operate the well drilling, completion, and workover equipment. When the well site operator does not own the equipment or control the operation or maintenance of the equipment, it is not appropriate to require reporting and compliance tasks of the well site operator because they do not participate in engine maintenance or the collection of fuel use data. All other CAA programs establish applicability based on whether a party owns and/or operates a source because it is not feasible for a person lacking control of a source's day-to-day operation to collect the required information or monitor the source's usage. IPAMS requests that EPA clearly state in this part that only the equipment a party owns and/or operates be included in that party's reported emissions inventory.

Response: EPA does not agree with the commenter. For further details, please see the response to EPA-HQ-OAR-2009-0923-1031-21.

Comment Number: EPA-HQ-OAR-2009-0923-1298-56
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Section 98.238: The definition for Onshore petroleum and natural gas production facility includes all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin.

The preamble states that the information gathered by the implementation of this rule would inform and guide EPA in carrying out a wide variety of CAA provisions. It is understood that EPA will use the GHG emission inventory data to define future permitting and compliance programs. For this reason, IPAMS does not agree with redefining the term "facility" in this part. If EPA uses the information in this program for other CAA programs, it must be collected in a manner that is consistent with how it will be applied in those programs.

Future GHG permitting and compliance programs will still rely on the definition of facility as found in 40 CFR 52.21(b)(6):

Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1298-57
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
In accordance with this definition and multiple case-by-case aggregation determinations made by EPA and the states, most production operations across a single hydrocarbon basin cannot be aggregated into one facility. If these production operations are not aggregated by basin, each facility or well site must individually be assessed for applicability to the future permitting and compliance programs. EPA has proposed an applicability threshold of 25,000 metric tons CO_2e per year for permitting, and that threshold will apply at the facility level. If the purpose of this rule is to inform future rulemaking, there is no benefit to collecting information for an aggregation of many small facilities that will not be subject to the future rules. IPAMS requests that EPA modify this “facility” definition to be consistent with the “facility” definition employed in other CAA programs.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1305-1
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Onshore Petroleum and Natural Gas Production Facility Definition

As EPA has noted, the “Onshore Petroleum and Natural Gas Production” segment of the industry is incredibly complex and diverse which makes crafting a regulation that is appropriate across this complexity extraordinarily difficult. Additionally, it is very different than the single facility focus of most EPA air quality regulatory focus. In the proposed Subpart W, EPA’s “geologic basin” approach is one of the mechanisms EPA employed to cope with these issues. BP believes that grouping GHG emissions from a particular owner/operator’s activities at the geologic basin level for wells and closely associated sites and activities has limited utility for threshold determination and reporting purposes, we do not believe it is beneficial from the standpoint of efficiently quantifying emissions while balancing burden with quality emissions data. EPA’s focus on millions of individual sites and pieces of equipment adds huge complexity to the effort of implementing and subsequent compliance with the rule without a corresponding increase in the data quality. BP suggests that these issues can be partially resolved by allowing owners/operators to group together similar operations and sources to enable “population sampling and averaging” approaches to emissions calculation rather than forcing emissions estimation on every individual source or individual piece of equipment within a basin. Most basins are quite complex and can have several different types of production, multiple dissimilar reservoirs, broadly differing fluid compositions and make-up, and different equipment and operational practices driven by the reservoir characteristics and type of production. This complexity poses a barrier to developing emissions estimation methods across a similar set of production wells and operations which appropriately balances burden and quality. Allowing the grouping of fields (in EIA’s field list) within a basin based on common production characteristics can enable approaches and methodologies that will achieve EPA’s articulated goal in the proposed rule of reducing burden without compromising data quality. These fields would be grouped based on the same type of production, same (or groups of similar) producing reservoirs, similar well depths and well-bore configurations, similar pressure and temperature ranges, similar fluid compositions and Gas-to-Oil Ratios (GOR’s), similar production arrangements and surface equipment, and similar operational characteristics and practices.

The following descriptions illustrate how these characteristics might be considered to group fields, in a defined basin, into sub-basin reporting units.

- Production type: grouping of fields or wells within fields on the basis of gas or oil production.

- Same or similar producing reservoirs: grouping of fields on the basis of reservoir types such as tight sands, coal bed methane, conventional sands, and shale gas. Different named formations/reservoirs with the same classification, such as tight sands, with less than 2,000 vertical feet between the formation tops could be grouped into one reporting unit/area.

- Similar ranges of pressure and temperature for the initial phase separation of production from the wells. Although the pressure can vary quite widely, for even the same producing horizon/formation, dependent on “well-head” compression the general collection and gathering system pressure in the fields being grouped should be similar.

- Similar fluid compositions such as oil with associated hydrocarbon gas, primary hydrocarbon gas production with hydrocarbon liquids that separate at field separators, “dry” gas with no appreciable (<2 bbls per MMSCF) hydrocarbon liquid production.

- Similar production arrangements, surface equipment, and operational characteristics/practices: Fields to be grouped should employ similar production approaches such as well-site phase separation with equipment located on or near individual well sites or small groups of wells, multi-phase flow to central separation and production facilities (such as central tank batteries).

Each covered operator in a basin would select the appropriate groupings of fields based on their particular operations and portfolio, using the above characteristics and guidance, and fully describe them in their monitoring plan along with their rational for a particular grouping. This “sub-basin entity” would enable the development of activity or emission factors and approaches based on the parameters that affect the amount and type of emissions from a particular reporting area. Although the proposed rule does enable this approach in limited instances and source types, the approach needs to be broadly expanded. Threshold determination and grouped reporting would be based on the summation of the "sub-basin entities" within a basin.

The comments later in this document regarding specific source categories/types expand on this concept by describing how such an approach would be applied.

"Facility" Terminology

To avoid the confusion which may develop regarding the definition of an "Onshore Oil and Gas Production Facility" at a geologic basin level BP suggests that a different term be used rather than "facility". The use of facility should be restricted to its traditional use such as a discrete oil and gas processing facility. BP suggests the term "Basin Entity" be used when referring to the grouping of a particular owner/operator's properties and activities within a basin for threshold analysis and reporting purposes.

BP does appreciate the clarification in the "frequently asked questions" that the use of "facility" to describe the basin level grouping of Onshore Oil and Gas Production Operations (Subpart W FAQ, March 2010) "do not impact requirements under other EPA regulations, for example, New Source Review (NSR)". However, we do not feel that the FAQ response provides adequate clarification of this issue and request that the clarification be incorporated directly into the rule language.

Requests:

- EPA should enable the grouping of similar named fields within a basin into a "sub-basin entity" for emissions determination based on the characteristics outlined above.

- EPA should add the statement that "the facility definitions in this rule do not impact requirements under other EPA regulations, for example, New Source Review (NSR)" to the regulation itself.

- EPA should use the term "Basin entity" when referring to the roll-up of "sub-basin entities" for assessing onshore oil and gas production operations against the reporting threshold.

Response: EPA disagrees with the commenter on the grouping of sub-basin entities. For further clarification, please see the response EPA-HQ-OAR-2009-0923-1305-46. As regards impact of this rule on other EPA regulations, please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details. EPA does not agree with the use of the term "basin entity" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1305-7
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:

Inclusion of Flare Stacks in Onshore Petroleum and Natural Gas Production

BP suggests that flare stack reporting be included in the Onshore Petroleum and Natural Gas Production source category. Many of BP's Alaska North Slope production operations have stationary flares located at their onshore production facilities and to be complete, the flare source type should be added. Therefore, BP recommends that flare stacks be added under 98.232 (c) (x). BP suggests that EPA retain the option to use engineering calculations, company records or similar estimates to compute volumetric flow. This same approach should be applied to the inclusion of flare stacks in Onshore Petroleum and Natural Gas Production.

Alaska North Slope Operations Source Category Classification

BP believes that the proper classification of the North Slope Alaska oil production operations, including the handling and use of associated natural gas, is Onshore Petroleum and Natural Gas Production. Although the Technical Support Document seems to support this conclusion, the rule is not completely clear and BP requests that EPA specifically clarify this uncertainty. Despite the large amount of associated gas which is handled and treated on a daily basis, the North Slope operations do not produce gas or NGL's for sales. The sole purpose is production of crude oil which supports the classification wholly within the Onshore Petroleum and Natural Gas Production source category.

Due to the comprehensive coverage of source types and the basin construct in the Onshore Petroleum and Natural Gas Production source category, classifying all of the North Slope crude oil production operations within this source category will not exempt significant emissions from coverage. BP requests that EPA clarify that all Alaska North Slope operations properly classify within the Onshore Petroleum and Natural Gas Production Category.

Response: EPA agrees with the commenter regarding flare stacks and today's final rule states that flare stacks are one of the emissions sources to be monitored and reported in the onshore petroleum and natural gas production segment. Today's final rule does allow use of engineering calculations based on process knowledge, company records or similar estimates to compute volumetric flow and composition of gas to flares.

EPA does not agree on grouping the natural gas processing facility on the North Slope of Alaska with onshore petroleum and natural gas production. In developing the petroleum and natural gas industry segments, EPA considered the major sources and how to gather emissions data in the most cost-effective manner. Natural gas processing facilities, such as that on the North Slope of Alaska, have very large, high pressure compressors, which are a significant source of emissions. Today's final rule requires measurement methods to assess those emissions in processing facilities. EPA determined that the size and widely dispersed nature of compressors in onshore production did not warrant this same degree of emissions determination, and in today's final rule, is allowing the use of equipment count and emissions factors for onshore production compressors. To designate the North Slope of Alaska processing facility with onshore production would not achieve the emissions data that EPA needs to inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-3524-1
Organization: Chesapeake Energy Corporation
Commenter: Grover Campbell

Comment Excerpt Text:
EPA has proposed defining a new term, "onshore petroleum and natural gas production facility ." See 75 Fed. Reg. 18,608 at 18,647 (Apr. 12, 2010). This definition is not consistent with industry's and regulators' existing interpretation of the term "facility" in the oil and gas ("O&G") upstream sector under the Clean Air Act ("CAA"). Therefore, Chesapeake recommends that if EPA plans to aggregate exploration and production sites, EPA should use a different term, such as a "threshold reporting area" or "roll-up area threshold" to define the geographical area that upstream oil and gas facilities will use to assess the Mandatory Reporting Rule ("MRR") applicability threshold. Utilizing a different term for this geographic area would help alleviate any confusion that might arise from the use of the word "facility" as used in other sections of the CAA.

If EPA adopts Chesapeake's suggested terminology, the definition of "onshore petroleum and natural gas production facility" would need to be modified to read as follows: "Onshore petroleum and natural gas production reporting area means all petroleum or natural gas facilities and equipment associated with all petroleum or natural gas production under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined. . . . .. 40 C.F.R. § 98.238.
If EPA adopts this terminology, the term "reporting area" would also need to be incorporated into the definition of the source category of onshore petroleum and natural gas production as follows: "Onshore petroleum and natural gas production . Onshore petroleum and natural gas production reporting area means all facilities associated with the production of petroleum or natural gas including but not limited to. . . ." 40 C.F.R. § 98 .230(a)(2) .

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1. EPA does not agree with the use of the term “reporting area” instead of “facility”. For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo “Early Comment Submissions” in docket EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-2
Organization: American Petroleum Institute
Commenter: Karen Ritter

Comment Excerpt Text:
Second, API concurs with EPA’s statement that, quote, “the facility definitions proposed in this rule do not impact requirements under other EPA regulations, for example, new source review,” end of quote. While here in Subpart W, there may be a need to cluster equipment in activities for

reporting, the terms used in conjunction with the facility definitions under Subpart W should not impact any current or future aggregation determinations

Response: As regards impact of this rule on other EPA regulations, please see response to EPA-HQ-OAR-2009-0923-1174-5 for further details.

14.1.1 BASIN

Comment Number: EMAIL-0001-2 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

__**Comment Excerpt Text:**__
Upstream Production Sites Should Not Be Aggregated

EPA should not require aggregation of upstream production sites. This imposes a disproportionate burden on our industry by requiring data collection, recordkeeping, and reporting for hundreds of thousands of operated sites. As the rule is written, even very small operators will have to calculate and aggregate GHG emissions to determine if they must report or not report.

EPA states in the preamble that the information gathered by this rule would inform and are relevant to EPA's carrying out a wide variety of Clean Air Act (CAA) provisions. It is understood that the GHG emission inventory data will be used to define future permitting and compliance programs. For this reason, we do not agree with redefining the term "facility" in this part. If the information in this program will be used for other CAA programs, then it must be collected in a manner that is consistent with how it will be applied in those programs.

Future GHG permitting and compliance programs under the CAA will still rely on the definition of facility as found in 40 C.F.R. 52.21(b)(6):

Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

In accordance with this definition and multiple case-by-case aggregation determinations by EPA and the states, most production operations across a single hydrocarbon basin cannot be aggregated into one facility. If these production operations are not aggregated by basin, then each facility or well site must individually be assessed for applicability to the future permitting and compliance programs. At this time, an applicability threshold of 25,000 metric tons CO_2e or more per year has been proposed for permitting, and that threshold will apply at the facility level. If the purpose of this rule is to inform future rule-making, there is no benefit to collecting information for an aggregation of many small facilities that will not be subject to the future rules. We request that this definition be modified to be consistent with the definition employed in other CAA programs.

Response: To reduce burden on the industry, EPA plans to develop screening tools to assist in the determination of which facilities are required to report under today's final rule; please see Section II.F of the preamble to today's final rule for further details. This will avoid the burden to non-reporters in determining whether or not to report.

For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1, EPA-HQ-OAR-2009-0923-1044-6, and EPA-HQ-OAR-2009-0923-1005-2.

Comment Number: EMAIL-0001-4 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: American Exploration and Production Council
Commenter:

Comment Excerpt Text:
Basin Level Aggregation

EPA is seeking comment on whether to use "basin level" for aggregation as proposed, or "field level". If EPA goes forward with aggregation of upstream production sites, a "field level" approach would be much more practical for the following reasons:
• Some basins are very large (the Permian Basin stretches from southeast New Mexico and southwest Texas nearly to Louisiana. Basins can typically cross state lines such that GHG reporting by basin would not allow states or the EPA to determine which state the emissions are from. In addition, basins can cross multiple regional and district operating boundaries for companies making gathering of emissions information data more difficult.
• EPA has overestimated the reduction in emissions coverage for field level aggregation versus basin level aggregation. Most large and small operators concentrate in producing from certain fields within a basin. The Barnett Shale in Texas covers 24 counties. However, one large independent operates approximately 2,000 wells, but with 95% of those in just three or four counties.
• The quality of emission estimates would be greater for emissions estimates made on a field level rather than a basin level. Oil and gas characteristics and the method of separation and processing are directly related to the field from which the oil and gas is produced. Fields are well defined by state oil & gas commission rules. When wells are comingled, the percent of production from a particular field (sand or formation) can be assessed using royalty calculations to provide the percentage production from a particular field. The field which produces the majority of the oil and gas for a comingled well can be used as the field that a well reports under.

• Aggregation by basin level would complicate efforts for simple auditing by EPA as it would be difficult to determine whether emissions reported are reasonable compared to emissions reported from other companies. EPA would not know how much production came from various fields within that basin.

• For all the above reasons, we support the API's proposed approach that would allow operators the flexibility to report at the basin level but allow them to identify rational "reporting units" within a basin that have similar operations, equipment, fluid properties, and physical properties, and enable the use of "population average" emission factors and approaches for emission quantification. This would allow calculation and reporting of emissions from reasonable "well groupings" such as known fields within a basin or even by county within a basin.

Response: EPA does not agree with the commenter on the reasons for using a field level facility definition. With regards to the size of the basin, please see response to EPA-HQ-OAR-2009-0923-1014-4 for further details. Furthermore, basins are more representative of characteristics of emissions and not State boundaries.

EPA does not agree with the commenter on the differences between field and basin level coverage. The commenter has provided an example that cannot be applied across the country. Oil and gas operations vastly vary in characteristics across the country and cannot be analyzed using specific case scenarios like the one provided by the commenter. Therefore, EPA has used actual data across the country to estimate emissions coverage, which is the mostly reasonable way of conducting the analysis. Please see Section 5 of the TSD for further details.

EPA requires the monitoring of certain emissions sources, e.g. well venting sources, by field so as to capture the variation in emissions patterns based on the characteristics of the field. The magnitude of emissions from other sources such as pneumatic devices do not depend on the type of formation, hence a field level reporting is irrelevant. Therefore, EPA does not find an issue with basin level reporting. As regards auditing, a basin level approach is in fact helpful to EPA since the delineation is based on county boundaries, which are easy to follow.

Finally, EPA does not agree with the use of the term "reporting units" instead of "facility". For further details, please see the response to EMAIL-0001-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

Comment Number: EMAIL-0009-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: EC/R Incorporated
Commenter: Robert Vogt

Comment Excerpt Text:
I was wondering if you could please tell me where to find a map of the basins specified in the GHG reporting rule for Subpart W.

In particular, the rule documents the use of the American Association of Petroleum Geologists (AAPG) classifications of a basin boundaries. Is there a map available that shows these basin boundaries? If so, could you please let me know where it can be found?

Response: The AAPG classification of basins is available as a list of codes and map from AAPG and the details on where they can be found are provided in Section 98.7 of today's final rule covering standardized methods incorporated by reference.

Comment Number: EPA-HQ-OAR-2009-0923-3546-1
Organization: Texas Commission on Environmental Quality
Commenter: Mark R. Vickery

<u>Comment Excerpt Text:</u>
The term "basin" is not defined in the rule language but is discussed in the preamble. The TCEQ recommends that the definition of basin, because of its importance in the definition of a facility for the onshore petroleum and natural gas production sector reporting, be added to the rule.

Response: EPA agrees with the commenter. In today's final rule, EPA has provided a separate definition for basin. Please see Section 98.238 – Definitions of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1014-4
Organization: Independent Oil and Gas Association of West Virginia
Commenter: Charlie Burd

<u>Comment Excerpt Text:</u>
Furthermore, IOGA-WV notes that the size of the AAPG's designated hydrocarbon basins varies dramatically across the country. Indeed, the entire state of West Virginia is divided into only two AAPG hydrocarbon basins-the "Appalachian basin" (160) and the "Appalachian basin (Eastern Overthrust area)" (l60A)-both of which span hundreds of miles along the entire Appalachian region, from New York down to Tennessee, Alabama and Georgia. In contrast to the vast hydrocarbon basins that encompass the Appalachian region, many of the AAPG basins in the central and western parts of the country are a mere fraction of this size. Relying on the AAPG's delineations thus imposes a significantly disparate impact on individual oil and gas operators depending on the geographic region in which their operations are located. The substantial variation in the size of the AAPG basins effectively eliminates them as an appropriate basis for determining the applicability of a nationwide emissions reporting scheme

Response: EPA does not agree with the commenter. In any facility definition, either defined using physical or geographical boundaries, there are always facilities of various sizes. This is the case with all industries, not just oil and gas. Hence, EPA does not consider the varying basin size as defined by AAPG as an issue and retains this definition for the purpose of this rulemaking. For further details on why EPA chose the AAPG basin definitions, see Section II. D of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1024-15
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:

Reporting of Onshore Production Emissions at Basin Level. All wells within a producing basin should not be classified as a single "onshore production facility."[247] National Emissions Standards for Hazardous Air Pollutants (NESHAPS),[248] and New Source Review (NSR) – have always defined a stationary source or "facility" as a discrete equipment site, such as an individual wellhead.[249] Indeed, Section 112 of the CAA explicitly prohibits the aggregation of multiple oil and gas wells, including those under common ownership and control, for purposes of determining applicability of hazardous air pollutant standards.[250] Introducing a different, and counterintuitive, definition of "facility" for the sole purpose of GHG reporting can only lead to confusion and inconsistency, given industry structure and long-established practice in other CAA programs.

In addition, grouping all wells within a basin together for purposes of reporting makes little conceptual sense. Basins tend to be extremely heterogeneous with respect to geology, fluid composition, and equipment and operational practices; hence, they are typically subdivided by operators into multiple fields or units. For example, all of Kinder Morgan's production is within the Permian Basin in West Texas, but Kinder Morgan maintains separate operations for four different fields within the Permian Basin, including the SACROC, Yates, Claytonville, and Katz Strawn fields. Given the heterogeneity of basins, it will be difficult to draw any meaningful policy conclusions from data collected at the basin level. Also, basins can typically cross state lines such that GHG reporting by basin would complicate the attribution of emissions to particular states.

Nevertheless, Kinder Morgan acknowledges EPA's concern that well-based reporting could yield a large number of emissions reports,[251] depending on the reporting threshold that is ultimately selected. To mitigate this potential problem, Kinder Morgan suggests that the basic unit of reporting should be a wellhead, not a production basin; however, the number of reports would be reduced by allowing reporting companies to group wellheads into coherent production fields based on geographic features, operational characteristics, and other appropriate factors. This approach would yield useful, policy-relevant data by grouping similar facilities together for

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[247] Proposed 40 C.F.R. SECTION 98.238.] Clean Air Act (CAA) regulations – including NSPS, [Footnote 19: See 40 C.F.R. SECTION 60.3 (defining "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant"). At 40 C.F.R. SECTION 52.21(b)(6), a "building, structure, facility, or installation" is defined as "all of the pollutant emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) . . . ."

[248] See 40 C.F.R. SECTION 63.760-777.

[249] See 40 C.F.R. SECTION 52.01(a) (defining "stationary source").

[250] 42 U.S.C. SECTION 7412(n)(4)(A).

[251] Proposed Subpart W, 75 Fed. Reg. at 18,615.

reporting purposes. At the same time, this approach would provide that the Mandatory Reporting Rule does not disturb the conventional definition of "stationary source" that has been consistently used in CAA programs,[252] and would allow for a manageable number of emission report submittals for both industry members and EPA.
If EPA elects not to adopt this approach, Kinder Morgan also supports the concept of field-based reporting, an approach EPA considers in the preamble to the proposed Subpart W.[253] Contrary to EPA's observation that "both [field and basin-level reporting] rely on geographical boundaries," production fields under common operatorship provide far more coherent and manageable reporting units than basins. As noted above, production basins can span multiple states and thousands of wells with completely different characteristics. Production fields, by contrast, tend to be geologically similar and contain wellheads that are comparable to each other and can be sensibly aggregated. A 25,000 metric ton CO2-e threshold, if applied to production fields designated by the Energy Information Administration, as EPA suggests in the preamble, would yield more than adequate coverage of onshore petroleum and natural gas production emissions while providing more useful data than basin-level reporting.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and responses to EPA-HQ-OAR-2009-0923-1044-1 and EPA-HQ-OAR-2009-0923-1005-2. EPA does not agree that basin level reporting will not provide meaningful information. Please see response to EMAIL-0001-4 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923) for further details.

EPA does not agree with the commenter on use of wellhead as a facility. Please see response to EPA-HQ-OAR-2009-0923-1005-6, EPA-HQ-OAR-2009-0923-1005-2, and , and EPA-HQ-OAR-2009-0923-1305-46 for further details. As regards characteristics of different fields and how they impact emissions, please see response to EMAIL-0001-4 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923).

EPA does not agree with the commenter that the field level reporting would provide adequate coverage of emissions. A field level reporting would result in about 28 percent less coverage than basin level reporting. Please see Section 5 of the TSD for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1298-3
Organization : Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>**Comment Excerpt Text:**</u>
Basin level reporting is not appropriate for natural gas and oil production sites. Defining a "facility" to include many wells and associated equipment over a large area is contrary to the

[252] In Section III.C of these comments, Kinder Morgan raises a similar concern with respect to the use of the term "facility" in the proposed Subpart RR.

[253] Proposed Subpart W, 75 Fed. Reg. at 18,615.

Clean Air Act (CAA) definition and will subject many small companies to the reporting requirements, contrary to EPA's stated goal of limiting impacts to small businesses.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments. For EPA analysis on the impact on small businesses, please see Section 5.2 of the EIA to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-3
Organization: American Petroleum Institute
Commenter: Karen Ritter

Comment Excerpt Text:
EPA should define a simple and innovative system that balances the data collection and reporting burden against the amount of emissions quantified. To achieve this simplification and balance, API suggests that EPA allow operators to identify rational reporting units within a basin that have similar operations, equipment, fluid properties and physical parameters and enable a broader use of population average emission factors and approaches for emissions quantification. API recognizes that the reporting threshold determination may still rest with the basin level facility and the construct of the reporting units below the basin level will be implemented in such a manner that they will cover all relevant operations of a given owner or operator within the defined basin

Response: EPA does not agree with the commenter on the use of reporting units within a basin. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-46.

14.1.2 FIELD

Comment Number: EPA-HQ-OAR-2009-0923-1074-3
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
75 FR 18615: C. Definition of the Source Category, Onshore Natural Gas
Processing

Comment: WBIH recommends Field Level reporting for onshore petroleum and natural gas production with a reporting threshold of 25,000 mtCO2e.

EPA is seeking comments on advantages to require reporting at the field level instead of the basin level. The purpose of the Energy Information Administration Oil and Gas Field Code Master publication is to provide standardized names and codes for identifying domestic fields. "Use of these field names and codes fosters consistency of field identification by government and industry. As a result of their widespread adoption they have in effect become a national standard."

Referencing the discussion regarding the combination of direct measurement and engineering estimation, specifically related to flaring and unconventional well drilling, EPA stated "As a result, EPA proposes the development of a field-specific emission factor either by direct measurement of flow rate of hydrocarbons using a meter or by and engineering estimation based on choke pressure drop." Field level reporting provides the opportunity to use similar gas and oil compositions for emissions quantifications and supports EPA desire to develop field-specific emissions factors, which is more credible data for development of GHG regulatory programs. One size does not fit all

Response: EPA does not agree with the commenter and is retaining the basin level facility definition in today's final rule. . The AAPG basin definition is as standardized as the EIA Field Code Master, so there is no distinct advantage in terms of standardization in using the field over the basin as a facility definition. In addition, section of the preamble to the April 2010 proposed rule referenced by the commenter refers specifically to well venting sources where sampling within a field has been allowed as an option. EPA notes that this is in no way related to other emissions source types where such a sampling option is not provided in the rule. Also, the well venting sampling option is provided for fields within a reporting basin.

Comment Number: EPA-HQ-OAR-2009-0923-3568.1-3
Organization: American Gas Association
Commenter: Pamela Lacey

Comment Excerpt Text:
First, we believe you cast your net too broadly when defining the concept of "facility" for natural gas distribution. As a result, the proposed rule would likely apply to many more gas utilities and require a much greater burden than you estimate. It is not clear to us whether you intend to define the facility as each distribution system or as all of the distribution systems owned by a single "Distribution Company." The two are not aligned all the time. If you plan to combine all of the separate distribution systems of a single company in one facility that spans hundreds of communities if not thousands across a state – some of our companies span several states as well – you would have many more utility companies that would be likely to exceed your 25,000 ton per year threshold for reporting.

Response: EPA disagrees that it cast the net too broadly with the definition of facility for natural gas distribution. Please see the response to comment EPA-HQ-OAR-2009-0923-1016-26 for further details.

14.2 DEFINITION OF NATURAL GAS

Comment Number: EPA-HQ-OAR-2009-0923-1080-32
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Aka strongly recommends that the definition in Section 98.230(a)(3) be revised to exclude field gathering and boosting stations from the Onshore Natural Gas Processing source category definition, and that a new source category definition be included for "Onshore Natural Gas Gathering Compression." Using the definition of Onshore Natural Gas Transmission as a template, AKA respectfully requests that the source category definition for "Onshore Natural Gas Gathering Compression" be changed to the following:

Onshore natural gas gathering compression means any physically adjacent combination of compressors that move natural gas from production fields or other compression facilities into natural gas processing facilities, other gathering compression facilities, transmission pipelines, storage facilities, or other end users. In addition, natural gas gathering compressor facilities may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

Response: EPA has not included field gathering and boosting stations from the Onshore Natural Gas Processing source category in today's final rule. For further information, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-30
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The Sour Natural Gas definition states that it is natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas. The concentration of carbon dioxide does not determine whether natural gas is considered "sour." The oil and gas industry considers natural gas to be "sour" based only on the gas' hydrogen sulfide concentration. Although carbon dioxide content is indirectly controlled by heat content specifications, most natural gas contracts do not contain a specification for carbon dioxide content unless the natural gas contains an excessive concentration of carbon dioxide. In addition, the concentration of hydrogen sulfide at which a natural gas stream is considered "sour" is not a standard value across the industry. This concentration varies according to the production area and the sales contract. We request that the "sour natural gas" definition not reference carbon dioxide content, and we suggest that EPA define the concentration of hydrogen sulfide at which natural gas is consistently considered "sour" to be at least 100 ppmv.

The Sweet Gas definition states that it is natural gas with low concentrations of hydrogen sulfide and/or carbon dioxide. As discussed in the comment for sour natural gas, the concentration of carbon dioxide does not determine whether natural gas is considered "sour" or "sweet." We request that the "sweet gas" definition not reference CO2 content.

Response: EPA has reviewed these comments and disagrees that any composition conditions should be placed on the definitions of sour or sweet natural gas. The reporting requirement is related to gas feed to an acid gas removal unit and gas that is suitable for transmission, distribution and sales. The terms as used in subpart W have no effect other than to distinguish between gas suitable with regard to H_2S and CO_2 content for sales and gas requiring acid gas removal.

14.3 ONSHORE GAS PROCESSING BOUNDARY (PRODUCTION VERSUS PROCESSING)

Comment Number: EMAIL-0002-1 (comment also located in rulemaking memo "Early Comment Submissions" in docket EPA-HQ-OAR-2009-0923)
Organization: Gas Processors Association
Commenter:

Comment Excerpt Text:
Defining natural gas gathering system compression facilities as part of a gas processing plant is inappropriate.

The definition of a gas processing plant is well established in the context of the Clean Air Act and it does not incorporate stand alone gathering system compression facilities. Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission sector, are discreet and easily identifiable facilities. These facilities have been treated as stand alone sites in all previous applications of the Clean Air Act, including all permitting programs and for GHG reporting under 40 CFR Part 98 Subpart C. Continuing this historical treatment of these facilities is not only the most appropriate action, it will also eliminate the certain confusion that will result from a new definition solely for use in Subpart W of Part 98.

Even the EPA appropriately recognizes the treatment of gathering system compressor stations as stand alone facilities. On page 26 of the Background Technical Support Document for the Petroleum and Natural Gas Industry, the EPA states:

"Both gathering/boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place".

Further, on page 18613 of the Subpart W preamble the EPA states that,

"For some segments of the industry (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities."

In direct conflict to the above statements, the proposed Subpart W definition of Onshore Natural Gas Processing in §98.230(3) appears to require GHG emissions from gathering compression facilities and the gathering pipelines be rolled-up with gas processing plant emissions by stating (emphasis added):

“In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant.”

GPA strongly recommends the above text in §98.230(3) be deleted from the Onshore Natural Gas Processing source category definition and a new source category definition be included for “Onshore Natural Gas Gathering Compression”. Using the definition of Onshore Natural Gas Transmission as a template the source category definition for “Onshore Natural Gas Gathering Compression” should be:

“Onshore natural gas gathering compression means any fixed combination of compressors that move natural gas from production fields or other compression facilities into natural gas processing facilities, other gathering compression facilities, transmission pipelines, storage facilities, or other end users. In addition, natural gas gathering compressor facilities may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. “

GPA also suggests that the same GHGs and sources reported by processing plants under §98.232(d) be reported by gathering compression facilities.

In addition to the conflicts created by the proposed definition in Part 98, Subpart W regarding applicability of gathering compression facilities, the following issues arise from the proposed Subpart W definition of Onshore Natural Gas Processing in §98.230(3).

a) Increases the number of facilities subject to Subpart C for combustion GHG emissions by approximately 15 times, with no consideration for the size of each individual facility. This results from the fact that, numerically, there are typically 10-20 gathering compression facilities for every gas processing plant.

b) Gathering compression facilities are often not uniquely associated with a single gas plant, many gathering compression facilities have connections to multiple gas plants and gas is routed to a plant based on business needs and conditions. Associating any one gathering compression facility to an individual processing plant is not always possible.

c) Rolling-up gathering compression facility emissions with processing plant emissions is in conflict with EPA's assessment of the impact of the proposed Subpart W. EPA inaccurately states in the proposed Subpart W preamble on page 18616,

"… there are a reasonable number of reporters. Most natural gas processing facilities proposed for inclusion in this supplemental proposed rulemaking would already be required to report under subpart C and/or subpart NN of the Final MRR."

In fact, this proposal will increase the number of facilities subject to Subpart C for compression GHG emissions by approximately 15 times. One GPA member company that has about 45 facilities subject to Subpart C reporting for 2010 would have over 700 facilities subject to Subpart C as a result of this proposal. This level of reporting with no consideration for individual facility emission levels is neither reasonable nor appropriate.

d) EPA makes the following conclusion on page 18619 in the preamble to the proposed Subpart W,

"… requiring only a small fraction of total facilities to report."

The proposed Subpart W in fact increases coverage of gas gathering and processing facilities to nearly 100% regardless of facility size, which is unduly burdensome and neither reasonable nor appropriate.

e) Gathering compression facilities are typically small facilities and widely dispersed, many of these compression facilities have only 1 or 2 compressors. Significantly sized facilities are already subject to Subpart C reporting if the combustion emissions exceed 25kTon/year and individual compression facilities that exceed 25kTons/year including Subpart W emissions would also begin reporting as required. The proposed Subpart W, however, treats these small and widely dispersed facilities as if they are the same size and complexity of a gas processing plant. Examples of proposed requirements that may be appropriate for processing plants but unduly burdensome for small and widely dispersed gathering compression facilities include: collecting extensive data and modeling tank emissions, compressor rod packing vents, leak detection using optical imaging or population factors, and quarterly sampling of gas streams.

Response: EPA has decided not to include natural gas gathering and boosting in today's final rule. For more information, please see Section II.F of the preamble to today's final rule. As a result of excluding natural gas gathering and boosting, EPA has redefined onshore natural gas processing and onshore petroleum and natural gas production to reflect this change. EPA has also clarified the boundary between onshore processing and transmissions compressor stations. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14. However EPA disagrees, and continues to include residue gas compressors in the gas processing facility, that are owned and operated by a gas processing facility, and dedicated to moving sales gas from that gas processing facility to a transmission system, whether inside or outside the processing facility fence line. Residue gas compressors are large sources of emissions and move a significant output of the processing facility, and therefore are included in gas processing. Please see response to comment EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1015-19
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
PAW believes that it is unclear when Production is required to include gathering, and when boosting/processing includes gathering. PAW reiterates that it is unclear in the rule where Production site responsibility ends and Gathering/Processing site responsibility begins.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1015-28
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
98.230(a)(3): Onshore Natural Gas Processing Plant Source Definition. In NSPS KKK, a natural gas processing plant is defined as, "any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products." EPA's treatment of onshore natural gas processing plants does not appear to align with the NSPS KKK definition of "natural gas facility." For purposes of applicability, a gathering/boosting station without gas processing is not subject to the requirements of KKK. Therefore, a gathering/boosting station that is not owned by a processing plant should not be considered part of that processing plant facility.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F. of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1015-33
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
98.232(c)(9): Gathering pipeline fugitives. PAW believes that it is unclear when Production is required to include gathering, and when boosting/processing includes gathering. PAW reiterates that it is unclear in the rule where Production site responsibility ends and Gathering/Processing site responsibility begins.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates other segments. For further details, please see Section 98.2 of today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1015-6
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
In Subpart W 98.230(a)(3) Onshore Natural Gas Processing Plant Source Definition, PAW believes that this definition overlaps with processing plants, which also include gathering lines. It is unclear in the rule where Production site responsibility ends and Gathering/ Processing site responsibility begins. Furthermore, the rule does not specifically imply that gathering and boosting leading to a gas plant must be under common ownership/control of the gas plant in order to be included with the gas plant’s GHG emissions. Furthermore, it is not explicitly clear that the associated equipment (e.g., upstream compression and gathering) of gas processing facilities must be under common ownership and control. EPA should clarify this point.

Response: Today’s final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today’s final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1024-4
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
EPA should create an onshore natural gas gathering source category that addresses natural gas gathering facilities in the same manner as natural gas transmission facilities. Neither the industry nor EPA in other Clean Air Act programs has treated gathering facilities as part of onshore production facilities or processing plants.

Response: Today’s final rule does not include gathering and boosting sector. For further details, please see Section II.F of the preamble to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1026-6
Organization: Dominion Resources Services. Inc.
Commenter: Pamela Faggert

Comment Excerpt Text:
Natural Gas Processing Facility Definition

The proposed definition of natural gas processing facilities includes "gathering and boosting stations that dehydrate and compress natural gas to be sent to natural gas processing facilities or directly to natural gas transmission or distribution systems." The definition of a gas processing plant is well established in the context of the Clean Air Act and it does not incorporate stand alone gathering system compression facilities. Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission sector, are discreet and easily identifiable facilities. These facilities have been treated as stand-alone sites in all previous applications of the Clean Air Act, including all permitting programs and for GHG reporting under 40 CFR Part 98 Subpart C. Continuing this historical treatment of these facilities is not only the most appropriate action, it will also eliminate the certain confusion that will result from a new definition solely for use in Subpart W of Part 98.

Even the EPA appropriately recognizes the treatment of gathering system compressor stations as stand- alone facilities. On page 26 of the Background Technical Support Document for the Petroleum and Natural Gas Industry, the EPA states:

"Both gathering/boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place".

Further, on page 18613 of the Subpart W preamble the EPA states that,

"For some segments of the industry (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities. "

In direct conflict to the above statements, the proposed Subpart W definition of Onshore Natural Gas Processing in §98.230(3) appears to require GHG emissions from gathering compression facilities and the gathering pipelines be rolled-up with gas processing plant emissions by stating (emphasis added):

"In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are
considered part of natural gas processing plant. "

Dominion strongly urges that the above text in §98.230(3) be deleted from the Onshore Natural

Gas Processing source category definition and a new source category definition be included for "Onshore Natural Gas Gathering Compression" because gathering facilities are stand alone facilities and should be treated as separate facilities for applicability purposes. Using the definition of Onshore Natural Gas Transmission as a template the source category definition for "Onshore Natural Gas Gathering Compression" should read:

"Onshore natural gas gathering compression means any fixed combination of compressors that move natural gas from production fields or other compression facilities into natural gas processing facilities, other gathering compression facilities, transmission pipelines, storage facilities, or other end users. In addition, natural gas gathering compressor facilities may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. "

In addition to the conflicts created by the proposed definition in Part 98, Subpart W regarding applicability of gathering compression facilities, the following issues arise from the proposed Subpart W definition of Onshore Natural Gas Processing in §98.230(3). These issues would be resolved by creation of a specific source category for onshore natural gas gathering compression.

a) Increases the number of facilities subject to Subpart C for combustion GHG emissions by approximately 15 times, with no consideration for the size of each individual facility. This results from the fact that, numerically, there are typically 10-20 gathering compression facilities for every gas processing plant.

b) Gathering compression facilities are often not uniquely associated with a single gas plant, many gathering compression facilities have connections to multiple gas plants and gas is routed to a plant based on business needs and conditions_ Associating anyone gathering compression facility to an individual processing plant is not always possible.

c) Rolling-up gathering compression facility emissions with processing plant emissions is in conflict with EPA's assessment of the impact of the proposed Subpart W. EPA inaccurately states in the proposed Subpart W preamble on page 18616,

" ... there are a reasonable number of reporters. Most natural gas Processing facilities proposed for inclusion in this supplemental proposed rulemaking would already be required to report under subpart C and/or subpart NN of the Final MRR."

In fact, this proposal will dramatically increase the number of facilities subject to Subpart C for compression GHG emissions by approximately 15 times, essentially increasing coverage of gas gathering and processing facilities to nearly 100% regardless of facility size, which is unduly burdensome and neither reasonable nor appropriate.

d) Gathering compression facilities are typically small facilities and widely dispersed. Many of these compression facilities have only I or 2 compressors. Significantly sized facilities are already subject to Subpart C reporting if the combustion emissions exceed 25k Ton/year and individual compression facilities that exceed 25kTons/year including Subpart W emissions would also begin reporting as required. The proposed Subpart W, however, treats these small and widely dispersed facilities as if they are the same size and complexity of a gas processing plant. Examples of proposed requirements that may be appropriate for processing plants but unduly burdensome for small and widely dispersed gathering compression facilities include: collecting extensive data and modeling tank emissions, measuring leaks from compressor rod packing vents, leak detection using optical imaging or population factors, and quarterly sampling of gas streams.

Response: Today's final rule does not include the gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1058-9
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

<u>Comment Excerpt Text:</u>
Including field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas as feed to processing plants is inappropriate. Definition of this activity is well established in the context of the Clean Air Act, which does not incorporate processing and compression into one operation. Incorporating these operations into one reporting unit conflicts reporting requirements under other portions of this Part, specifically 40 CFR Part 98, Subpart C. We recommend EPA separate these activities into separate reporting units.

Response: Today's final rule does not include the gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1060-18
Organization: Yates Petroleum Corporation
Commenter:

<u>Comment Excerpt Text:</u>
Source Type:
Gathering Pipeline Fugitives

Regulatory reference for calculation/ monitoring requirements:
40 CFR 98.233(r)

Monitoring requirements/parameters:

Use Eq. W-19 to calculate emissions from all sources listed in 98.233(r) - see comment for listed sources.
1. Total number of each type of emission source listed in 98.233(r)
2. For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHGi (CH_4 or CO_2) in produced natural gas or feed natural gas; for other facilities listed in § 98.230 (b)(3) through (b)(8), GHGi equals one.
3. Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.
2. If the tank vapors are continuous then use a meter (such as a turbine meter) to measure tank vapors.
3. Use the appropriate gas composition from 98.233(u)(2)(iii) (i.e., the GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities).
2. Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

Comments:
Yates Petroleum Corporation believes that it is unclear when Production is required to include gathering, and when boosting/processing includes gathering. Yates Petroleum Corporation reiterates that it is unclear in the rule where Production site responsibility ends and Gathering/Processing site responsibility begins.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1060-5
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
In Subpart W 98.230(a)(3) Onshore Natural Gas Processing Plant Source Definition, Yates Petroleum Corporation believes that this definition overlaps with processing plants, which also include gathering lines. It is unclear in the rule where Production site responsibility ends and Gathering/ Processing site responsibility begins.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1061-3
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:

The current definition of the "onshore natural gas processing plants" source category is too broad. Proposed § 98.230(a)(3) would define "natural gas processing plant" to include upstream components that should be considered separate from the plant itself, including gathering lines and/or booster stations or compressor stations. Most importantly, upstream compressor stations should not be considered as part of the onshore natural gas processing plant. Emissions from upstream compressor stations should not be aggregated with emissions from components that are properly considered as part of the plant. In practice, compressor stations are considered to be separate from processing plants. Disaggregating such components from the plant would be consistent with industry practice and would eliminate a significant problem with the proposed language: the fact that upstream compressor stations are not always tied to or associated with a single processing plant. There is a significant amount of interconnection between various gas pipelines, compressor stations, and processing plants, such that a given compressor station may be connected to and deliver gas to any number of different processing plants. Accurately aggregating plant + compressor station emissions in this context would be difficult or impossible.

Accordingly, the following sentence from § 98.230(a)(3) should be revised as follows: "[strike though: In addition, f] Field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas [strike through: (including but not limited to flow lines or intra facility gathering lines or compressors)] as feed to the natural gas processing plants should be considered stand alone components for applicability under this source category, consistent with applicable provisions in Subpart C [strike through: are considered a part of the processing plant.]"

Another problem with § 98.230(a)(3) is its provision that "[a]l1 residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant." This provision should not be a blanket rule.

Equipment that is outside the plant's fence should be aggregated with the plant only if those facilities are operating under the same Title V permit

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14 As regards residue compressors outside the fence line of the processing facility, EPA does not find any issue with reporting emissions from them since the reporting requirement states that the processing facility will only report residue compressors that they own or operate. This data collection rule is not bound by Title V permitting requirements; please see response to EPA-HQ-OAR-2009-0923-1044-1 for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1074-25
Organization: WBI HOLDINGS

Commenter:

Comment Excerpt Text:
Comment on 98.230(a)(3): Onshore natural gas processing plants.

WBIH strongly recommends natural gas gathering and boosting stations be removed from the onshore natural gas processing industry segment and included with onshore petroleum and natural gas production industry segment. Natural gas gathering compressor stations and boosting stations are considered "production field facilities" for current air quality permitting programs and emission inventories

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1074-4
Organization: WBI HOLDINGS
Commenter:

Comment Excerpt Text:
Comment: WBIH strongly recommends natural gas gathering and boosting stations be removed from the onshore natural gas processing industry segment and included with onshore petroleum and natural gas production industry segment

Natural gas gathering and boosting stations are considered "field production facilities" for current air quality permitting programs and emissions inventories. The North American Industry Classification System (NAICS) code for field production facilities is 211111 and the SIC code is 1311

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1080-2
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
The rule requires compressor stations to be included with processing plants. However, compressor stations are frequently connected to more than one processing plant so that multiple flow paths are possible. The proposed rule provides no guidance for how to address this

situation. Complicating the matter further, multiple companies may own the compressor stations connected to a plant. Again, the rule is not clear on how to handle reporting in such situations.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1080-36
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
Aka recommends that the source categories and definitions (§98.236(a)) for "onshore natural gas production facility" and "onshore natural gas processing plant" clearly define the difference between the operations to extirpate overlap between the two.

Response: In today's final rule, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14 EPA has also clarified the definition of onshore natural gas processing facilities; please see section II.F of the preamble to today's final rule for further details.

Comment Number: EPA-HQ-OAR-2009-0923-1080-45
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
An onshore natural gas production facility may contain some of the processes that are currently defined as part of an onshore natural gas processing plant (e.g., the removal of water, condensate, and/or oil). Due to this confusion in the definitions of "production" and "processing," many production facilities could fall into both categories. This will result in different operators defining their operations inconsistently, and will most likely result in facility emissions being double counted in both source categories.

Response: In today's final rule, EPA does not require reporting of emissions from the gathering and boosting segment of the industry. In addition, EPA has provided a facility throughput for non-fractionation processing facilities below which they are not considered processing facilities that will avoid any overlaps between onshore production and onshore processing facility definitions; please see Sections II.D and II.E of the preamble to today's final rule. Finally, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1080-48
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:

Gathering compression facilities are often not uniquely associated with a single gas plant, and many gathering compression facilities have connections to multiple gas plants, where gas is routed to a plant based on business needs and conditions. Associating any one gathering compression facility to an individual processing plant is not always possible.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-127
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(r) Gathering pipeline fugitives

Onshore Production Source Category: Gathering pipeline fugitives

Section 98.232 (c) (9) lists gathering gas pipeline fugitives as a reportable source type for onshore petroleum and natural gas production, however, Section 98.233 (r) includes gathering gas pipeline fugitives only for the natural gas processing sector.

Section 98.233 (r) (3) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table W-2 of this subpart for fugitive emissions from gathering pipelines.

As discussed previously in Section I.C of this document, API recommends designating "Onshore Natural Gas Gathering and Collection Systems" as a stand-alone sub-sector of the Onshore Petroleum and Gas Production (OPGP) category, separate from "Onshore Petroleum and Natural Gas Production" and "Onshore Natural Gas Processing Plants". This provides a clear distinction between production and processing operations, and eliminates duplicate reporting due to the overlap of some operations and equipment.

For gathering compressor stations, API recommends that these not be grouped for the purpose of threshold determination or reporting under Subpart W. Subpart C has already set the precedence for the definition of a "facility" and a compressor station, regardless of it being for transmission or gathering, the compressor station has been treated as a stand-alone "facility" under Subpart C. API requests that EPA remain consistent with its Subpart C rule and regard each gathering/boosting compressor station as an individual facility.

API also recommends that gathering pipelines be considered another separate reporting segment, consistent with EPA's statements in its Background Technical Support Document ("TSD"). EPA has acknowledged in its TSD that a separate reporting segment for gathering pipelines would be an appropriate option: "Unlike other segments of the petroleum and natural gas industry, gathering systems may be owned by producers, processing plants, transmission companies, local distribution companies, or independent gathering companies. Therefore, it is difficult to assign this portion of onshore production to one particular segment. One option is to require gathering pipelines to be reported as an emission source. The other option is to have a separate segment assigned to gathering pipelines. See Appendix F for further discussion on the options.” (reference TSD p.18).

Under Appendix F of the TSD, EPA further recognizes that gathering pipelines should be reported as a separate segment at the company level. “If GHG emissions from the natural gas gathering pipeline segment were included, it would be most straightforward to have emissions reported at the pipeline company level as this is consistent with the PHMSA reporting.” TSD p.108

Response: Today’s final rule does not include the gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today’s final rule. EPA has made appropriate adjustments to the monitoring methods and data reporting requirements per this change in today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1196-3
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

Comment Excerpt Text:
IPANM contends that the 98.230(a)(3) Onshore Natural Gas Processing Plant Source definition overlaps with processing plants, which also include gathering lines. It is unclear in the rule where Production site responsibility ends and Gathering/ Processing site responsibility begins. The rule does not clarify whether gathering and boosting lines leading to a gas plant must be under common ownership/control of the gas plant in order to be included with the gas plant’s GHG emissions. Furthermore, EPA must clarify what associated equipment such as upstream compression and gathering of gas processing facilities must be under common ownership and control in order to trigger the reporting requirements.

Response: Today’s final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today’s final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today’s final rule

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Comment Number: EPA-HQ-OAR-2009-0923-1198-10
Organization: West Virginia Oil and Natural Gas Association
Commenter: Nicholas DeMarco

Comment Excerpt Text:
The proposed rule includes a definition of "natural gas processing facility" that includes "gathering and booster stations that dehydrate and compress natural gas to be sent to natural gas processing facilities or directly to natural gas transmission or distribution systems." This proposed definition is inconsistent with the existing definition of a gas processing facility established in the context of the Clean Air Act which does not incorporate stand alone gather

system compression facilities. These types of facilities have been treated as stand alone sources in all previous applications of the Clean Air Act, including all permitting programs and for GHG reporting under 40 CFR Part 98 Subpart, and when treated alone, in most cases such facilities are so small that their. emissions never trigger permitting or reporting requirements. This definition is of particular concern in West Virginia, where more than one company may be involved between the production, processing, transmission and distribution of natural gas. In many cases, where a gathering compression facility is not uniquely associated with a single gas plant, associating anyone gathering compression facility to a individual processing plant is not always possible. In these cases it would be very difficult to even locate such equipment in order to inventory emissions. '

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule and Topic 2: Aggregation of Gathering and Boosting Systems with Processing Facilities in Volume 9 of the Response to Comments.

Comment Number: EPA-HQ-OAR-2009-0923-1206-16
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Alternatively, if EPA determines that GHG emissions from gathering lines must be reported, we recommend that a new source category definition for gathering lines be included in the rule. Such a definition should specify that gathering lines: (1) are located upstream of natural gas processing plants; (2) carry produced gas; (3) do not include piping within gas plants, compression facilities, and treatment facilities; and (4) do not include transmission lines, even if located upstream of a gas plant.

Response: Today's final rule does not include the gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-6
Organization: Gas Processors Association
Commenter: Jeff Applekamp**:**

Comment Excerpt Text:
Defining natural gas gathering system compression facilities as part of a gas processing plant is inappropriate.

The definition of a gas processing plant is well established in the context of the CAA, and it does not incorporate stand-alone gathering system compression facilities. Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission sector, are discreet and easily identifiable facilities. These facilities have been treated as stand-alone sites in all previous applications of the CAA, including all permitting programs and for greenhouse gas ("GHG") reporting under 40 CFR Part 98 Subpart C. Continuing this historical treatment of these facilities is not only the most appropriate action, it also will eliminate the certain confusion that will result from a new definition solely for use in Subpart W of Part 98.

EPA has repeatedly recognized the treatment of gathering system compressor stations as stand-alone facilities in past regulations and other documents, including in its Background Technical Support Document for the Petroleum and Natural Gas Industry, which states:

Both gathering/boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place.

U.S. Environmental Protection Agency, Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document ("TSD") at 20

In the proposed Subpart W preamble, EPA states:

For some segments of the industry (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities), identifying the facility is clear since there are physical Air and Radiation Docket and Information Center boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities.

75 Fed. Reg. at 18613.

The term "natural gas processing plant" has been previously and consistently defined in other EPA programs. A natural gas processing plant (gas plant) is defined under Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. See 40 CFR Part 60, Subpart KKK. Subpart KKK also defines natural gas liquids as the hydrocarbons, such as ethane, propane, butane, and pentane, that are extracted from field gas. Accordingly, "natural gas liquids" are those light-end hydrocarbons that are extracted from a natural gas stream that must be stored in a closed pressurized tank to be maintained as a liquid. Taken together, these definitions do not incorporate the removal of water, condensate, oil, H2S, CO2, or any other component other than natural gas liquids.

Additionally, natural gas processing plant (gas plant) is defined under the Chemical Accident Prevention program as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both, classified as North American Industrial Classification System (NAICS) code 211112 [previously Standard Industrial Classification (SIC) code 1321]. See 40 CFR Part 68.

In direct conflict with the foregoing statements by EPA and existing regulatory definitions, the proposed Subpart W definition of Onshore Natural Gas Processing in Section 98.230(a)(3) of the proposed rule appears to combine GHG emissions from gathering compression facilities and the gathering pipelines with gas processing plant emissions:

In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant.

75 Fed. Reg. at 18636 (emphasis added).

The oil and gas industry commonly understands the term "natural gas processing plant" to mean the extraction of natural gas liquids from a natural gas stream to meet the heat content specification of sales contracts. A Joule-Thompson unit or a refrigeration unit typically Air and Radiation Docket and Information Center completes this natural gas liquids extraction. It is not appropriate to introduce a different definition for "natural gas processing plant" in this program. The contrast between industry's longstanding usage of the term and other EPA regulations with the proposed definition in Subpart W will lead to confusion among owners and operators, and will be inconsistent with other existing EPA regulations under the Clean Air Act.

Accordingly, GPA strongly recommends that the definition in Section 98.230(a)(3) be revised to exclude field gathering and boosting stations, including any associated acid gas treating facilities, from the Onshore Natural Gas Processing source category definition, and that a new source category definition be included for "Onshore Natural Gas Gathering Compression and Treating Facilities." Using the definition of Onshore Natural Gas Transmission as a template, GPA respectfully requests that the source category definition for "Onshore Natural Gas Gathering Compression and Treating Facilities" be changed to the following:

Onshore natural gas gathering compression and treating facilities means any physically adjacent combination of compressors that move natural gas from production fields or other compression facilities into natural gas processing facilities, other gathering compression facilities, transmission pipelines, storage facilities, or other end users. In addition, natural gas gathering compression and treating facilities may include equipment for liquids separation, natural gas dehydration, acid gas removal, and tanks for the storage of water and hydrocarbon liquids. These facilities do not include equipment designed to extract natural gas liquids.

In addition to the conflicts created by the proposed definition in Part 98, Subpart W regarding applicability of gathering compression facilities, the following issues arise from the proposed Subpart W definition of Onshore Natural Gas Processing in §98.230(a)(3).

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1206-7
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The proposed rule increases in the number of facilities subject to Subpart C for combustion GHG emissions by approximately 15 times, with no consideration for the size of each individual facility. This results from the fact that, numerically, there are typically 10-20 gathering compression facilities for every gas processing plant.

b) Gathering compression facilities are often not uniquely associated with a single gas plant, and many gathering compression facilities have connections to multiple gas plants, where gas is routed to a plant based on business needs and conditions. Associating any one gathering compression facility to an individual processing plant is not always possible.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-8
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
Rolling-up gathering compression facility emissions with processing plant emissions is in conflict with EPA's assessment of the impact of the proposed Subpart W. EPA inaccurately states in the proposed Subpart W preamble:

… [T]here are a reasonable number of reporters. Most natural gas processing facilities proposed for inclusion in this supplemental proposed rulemaking would already be required to report under subpart C and/or subpart NN of the Final MRR.

75 Fed. Reg. at 18616.

In fact, this proposal will increase the number of facilities subject to Subpart C for compression GHG emissions by approximately 15 times. One GPA member company that has about 45 facilities subject to Subpart C reporting for 2010 would have over 700 facilities subject to Subpart C as a result of this proposal. This level of reporting with no consideration for individual facility emission levels is neither reasonable nor appropriate.

d) EPA makes the following conclusion in the preamble to the proposed Subpart W:

…[The rule would] requir[e] only a small fraction of total facilities to report.

75 Fed. Reg. at 18619.

The proposed Subpart W in fact increases coverage of gas gathering and processing facilities to nearly 100% regardless of facility size, which is unduly burdensome and neither reasonable nor appropriate.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see Section 98.2 of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1298-24
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
Section 98.230(a)(3): The Onshore natural gas processing plants source category states that those plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas, including oil and condensate removal, water removal, separation of natural gas liquids, sulfur and CO2 removal, fractionation of NGLs, or other processes, and also the capture of CO2. This definition is too broad and captures processes that occur throughout the entire natural gas production and processing system, not just at a gas processing plant. In particular, the phrase "oil and condensate removal" includes all production separators, and the phrase "water removal" includes dehydration units, free water knockouts, separators, skim tanks, etc. These types of units can exist anywhere from the production well site, through processing and transmission, to immediately before distribution.

Response: EPA does not agree with this interpretation of subpart W. All segments of the Petroleum and Natural Gas Systems rule with exception of onshore production and natural gas distribution generally conform to the definition of a facility in Section 98.6 of subpart A of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98). This section states that "reporting is at the facility level" with facility defined as "any physical property, plant … on one or more contiguous or adjacent properties in actual physical contact …" Under Subpart W, gas processing facilities conform to this facility definition with the one minor exception of residue gas compressors owned and operated by a processing facility, serving only that processing facility, but located outside the processing facility fence line. Onshore production equipment and operations are generally located outside the boundaries of a processing facility. Because similar equipment and operations may be performed at a wellhead in onshore production, such as liquids separation, compression or dehydration, does not make a wellhead a processing facility anymore than those same operations and equipment types conducted in a transmission compressor station or underground natural gas storage site make those facilities processing facilities. In today's final rule EPA has revised the definition of natural gas processing facilities in Section 98.230, to include those with fractionation, and those without fractionation with a gas throughput capacity of 25 mmscfd and above. Please see the preamble Section II.E and "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923. EPA recognizes the possibility of oil and/or gas producing wellheads being co-located within the boundaries of a processing facility, in which case those emissions would be reported as part of the processing facility emissions using methods defined for onshore production equipment. Please see the response to EPA-HQ-OAR-2009-0923-1024-14. In today's final rule EPA has revised the term facility in Section 98.238 for the purposes of subpart W for onshore production, which groups all equipment under a common owner/operator, associated with petroleum and natural gas production wells in a basin. Please see the preamble Section II.D to today's final rule. This definition overrides the "contiguous" condition in subpart A of The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98).

Comment Number: EPA-HQ-OAR-2009-0923-1298-48
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
Section 98.236(a): As discussed in the comment provided for the Onshore natural gas processing plants source category in Section 98.230(a)(3), an onshore natural gas production facility may contain some of the processes that are currently defined as part of an onshore natural gas processing plant (e.g., the removal of water, condensate, and/or oil). Due to this confusion in the definitions of "production" and "processing," many production facilities could fall into both categories. This will result in different operators defining their operations inconsistently, and will most likely result in facility emissions being double counted in both source categories. IPAMS requests that the source categories and definitions for "onshore natural gas production facility" and "onshore natural gas processing plant" clearly define the difference between the operations to extirpate overlap between the two.

Response: For further details, please see responses to EPA-HQ-OAR-2009-0923-1080-45, EPA-HQ-OAR-2009-0923-1024-14, and EPA-HQ-OAR-2009-0923-1298-24.

Comment Number: EPA-HQ-OAR-2009-0923-1305-47
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Section 98.233(r) Gathering pipeline fugitives

Section 98.232 (c) (9) lists gathering gas pipeline fugitives as a reportable source type for onshore petroleum and natural gas production, however, 98.233 (r) includes gathering gas pipeline fugitives only for the natural gas processing sector.

Section 98.233 (r) (3) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table W-2 of this subpart for fugitive emissions from gathering pipelines.

As discussed previously, BP recommends designating "Onshore Natural Gas Gathering and Collection" as a stand-alone sub-sector of Onshore Petroleum and Gas Production (OPGP) category, separate from "Onshore Petroleum and Natural Gas Production" and "Onshore Natural Gas Processing Plants". This provides a clear distinction between production and processing operations, and eliminates duplicate reporting due to the overlap of some operations and equipment.

Further, as a separate sub-sector, BP supports EPA's use of the default emission factor for gathering pipelines, as provided in Table W-1. Natural gas gathering pipelines are widely dispersed, are generally much smaller diameter, and typically operate at low pressures, resulting in a lower potential for emissions.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. For further details, please see response to EPA-HQ-OAR-2009-0923-1004-14.

Comment Number: EPA-HQ-OAR-2009-0923-1305-6
Organization: BP America, Inc.
Commenter: Karen St. John

<u>Comment Excerpt Text:</u>
Section 98.230(a)(2) and (3) Definition of the source categories for Onshore Petroleum and Natural Gas Production and Onshore Natural Gas Processing Plants

As proposed, the definitions under 98.203(a)(2) and (3) lack a clearly defined boundary between the two segments. While EPA asserts that the facility definition "can easily be applied to onshore natural gas processing…since the operations are all located in a clearly defined boundary" (Technical Support Document p.17), this is not the case in Subpart W, where EPA has expanded the definition of the natural gas processing plant to encompass additional assets and created an indistinct boundary as a result. The lack of clarity poses several problems. First, there is significant overlap between the two definitions in both the physical description and process descriptions. From the physical description standpoint, both definitions include gathering and boosting systems and sites which gather gas from multiple wells. By EPA's own acknowledgement, for gathering pipelines, "it is difficult to assign this portion of onshore production to one particular segment. From the process description standpoint, the definitions overlap in the areas of phase separation (into hydrocarbon liquids, gas, and water), dehydration of natural gas, stabilization of hydrocarbon liquids, and removal of NGL if pentane separated as a component of condensate is considered an NGL. A clear distinction between the production segment and processing segment must be made to avoid determinations that individual well sites are processing facilities and to avoid double counting sources under both production and processing.

Second, structurally, the somewhat simplistic linear construct of the two definitions does not fit the complexity of the actual industry ownership and operating structure, and may not be implementable as written. It appears that EPA is assuming gathering lines are dedicated to a specific gas processing plant. Operatorship/Ownership and routing of gathering and collection systems between the wells and processing plants is much more complex. Handling of at least three different patterns of operatorship/ownership must be considered and described with variations on each definition. These three patterns are:

1. One company operates/owns the wells, collection system, and gas processing facility.

2. One company operates/owns the wells and a second company operates/owns both the collection systems and processing facilities.

3. One company operates the wells, a second (or perhaps multiple) company operates the collection systems, and a third company operates the gas processing facilities.

This is further complicated by the fact that many collection systems, in any of the three patterns, are interconnected or "looped" to enable balancing of production against available collection, compression and processing capacity. On any given day a well or collection system booster station may be routed directly to processing facility A, be routed directly to processing facility B, or be shuttled to another collection system (or multiple) for routing to either processing facility A or B or an entirely different processing facility. In each of these scenarios, the operatorship of the collection systems and processing facilities can be different as described above. Also, in many instances, certain equipment located on individual well sites (dehydrators are common) are owned/operated by the collection system operator - which may or may not be the owner/operator of the processing facility that ultimately receives the gas. As individual gathering/collection system booster stations are routed to different processing facilities their status can change from inclusion with the receiving processing facility, inclusion with the wells which they serve, or to stand-alone facilities (or perhaps not covered due to the stand-alone definition being keyed to routing directly to a transmission line). This can occur on a day to day basis and make it very difficult to determine how a particular facility should be handled on a particular day.

EPA could best address the issues described above by modifying the two existing definitions and including a third definition for "Onshore Natural Gas Gathering and Collection Systems", which segments this portion of the Petroleum and Natural Gas Sector category into three segments rather than two. The reporting of gathering pipelines/systems as a separate segment is supported by EPA's Technical Support Document ("TSD"), which states that "Unlike other segments of the petroleum and natural gas industry, gathering systems may be owned by producers, processing plants, transmission companies, local distribution companies, or independent gathering companies. Therefore, it is difficult to assign this portion of onshore production to one particular segment. One option is to require gathering pipelines to be reported as an emissions source. The other option is to have a separate segment assigned to gathering pipelines." (TSD p.18).

Following are suggested revisions to clarify the source categories/segments as described above (proposed language changes/additions are shown in green):

Section 98.230(a)(2) Onshore petroleum and natural gas production. Onshore petroleum and natural gas production equipment means all structures *and equipment* associated with wells (including but not limited to compressors, generators, *separation equipment, dehydration equipment*, auxiliary non-transportation related equipment, *centralized flow or gathering stations, central tank batteries* or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation, *compression, pumping,* or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering, *separating, treating, compressing, or stabilizing* produced gas *and hydrocarbon liquids* from multiple wells *which is not included in the onshore natural gas gathering and collection systems or natural gas processing plants , all systems associated with fuel gas use to power onshore production activities, all systems associated with gas reinjection that is not for underground natural gas storage purposes,* all EOR operations using CO2, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island *which are owned/operated by the owner/operator of the well(s).*

NEW Section 98.230 (3)(a)(?) Onshore natural gas gathering and collection systems: Onshore natural gas gathering and collection systems along with their field gathering and/or boosting stations are intended to gather and process natural gas from multiple wellsites or other gathering/collection systems, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to natural gas processing plants or directly to a natural gas transmission or distribution facility. Onshore natural gas gathering and collection systems may include equipment and processes for phase separation, condensate and water removal, dehydration, stabilization or treating of petroleum and/or natural gas, compression, storage, and metering. However, the main purpose of an onshore natural gas gathering and collection system is the gathering and transport of gas prior to processing or transmission. Onshore natural gas gathering and collection systems do not include residue gas compression adjacent to and down-stream of a processing facility which are included with the processing facility if owned/operated by the same owner/operator of the processing facility

Section 98.230(a)(3) Onshore natural gas processing plants. Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO2 separated from natural gas streams for delivery outside the facility. *Gas treatment processes performed on associated gas produced from crude wells for use as fuel gas or for reinjection at an onshore production facility is not considered a natural gas processing facility for the purposes of this subpart.* ~~In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities.~~ All residue gas compression equipment *owned/*operated by a processing plant *and located in close proximity to the processing plant,* whether inside or outside the processing plant fence, are considered part of natural gas processing plant.

Response: Today's final rule does not require reporting of emissions from the gathering and boosting segment of the industry. For more information, see the Preamble, Section II.F to today's final rule. EPA further clarifies the distinction between onshore production and gathering/boosting by clarifying that equipment such as compressors, dehydrators, separators and tanks located on a well pad, or associated with a well pad are onshore production. EPA also does not agree with excluding "gas treatment processes performed on associated gas … for use as fuel gas or for reinjection" from the equipment covered by gas processing when that equipment is within the facility boundaries of a processing facility. Such equipment associated with a well pad would be onshore production equipment. EPA has also clarified the definitions for onshore production and onshore gas processing to avoid overlaps; please see response to EPA-HQ-OAR-2009-0923-1080-45 for further details. In today's final rule EPA has revised the definition of natural gas processing facilities in Section 98.230, to include those with fractionation, and those without fractionation with a gas throughput capacity of 25 mmscfd and above. Please see Section II.E of the preamble to today's final rule and "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-3524-5
Organization: Chesapeake Energy Corporation
Commenter: Grover Campbell

Comment Excerpt Text:
5. Natural Gas Gathering System Compression Facilities Should Not Be Included In the Definition of the Term Gas Processing Plant.
Chesapeake supports the comments submitted by Gas Processors Association regarding proposed Subpart W with respect to the term "gas processing plant" and the need to retain this definition as understood by industry and as defined under the CAA. See 40 C.F.R. § 68.3 . Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission sector, are discrete and easily identifiable facilities and should not be included in the definition of "gas processing plant" under Subpart W.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. In the final rule EPA has revised the definition of natural gas processing facilities in 98.230, to include those with fractionation, and those without fractionation with a gas throughput capacity of 25 mmscfd and above. Please see the preamble Section II.E and "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-3568.3-5
Organization: Sierra Club
Commenter: Anne Harvey

Comment Excerpt Text:
With regard to life cycle accounting, EPA's decision to require production and processing reporting is particularly important because oil and gas companies are increasingly promoting high carbon products like tar sands oil, liquefied natural gas and oil shale

Response: EPA has retained reporting of emissions from both production and processing segments of the industry in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-4
Organization: American Petroleum Institute
Commenter: Karen Ritter

Comment Excerpt Text:
Third, API is concerned that the rule includes inconsistencies and overlap in the demarcation of the different industry segments subject to Subpart W. It would be better if the industry segments were to be defined along typical ownership and operating arrangements such as producing well sites and associated equipment, gathering lines in lateral compression, and natural gas processing. This would avoid duplicative reporting. API suggests that EPA look to the definition of, quote, "transportation" in NESHAP's Subpart HHH to define where natural gas production and processing ends and where natural gas transmission begins.

Response: Today's final rule does not require reporting of emissions from gathering and boosting segment of the industry. For further details, please see Section II.F of the preamble to today's final rule. Furthermore, EPA has clarified the boundaries of onshore production as it relates to other segments. EPA has also clarified the boundary between onshore processing and transmissions compressor stations. For further details, please see Section 98.2 of today's final rule. EPA has considered the definition for transmission segment from NESHAP HHH and determined the facility boundary to be similar with Subpart W. The commenter does not provide details on what specific items in the NESHAP HHH should be considered and how it concerns Subpart W definition of transmission segment. Hence EPA has retained the definition of onshore natural gas transmission compression in today's final rule. In the final rule EPA has revised the definition of natural gas processing facilities in 98.230, to include those with fractionation, and those without fractionation with a gas throughput capacity of 25 mmscfd and above. Please see the Section II.E of the preamble to today's final rule and "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923.

14.4 USE OF "EQUIPMENT" LEAK VERSUS FUGITIVE AND VENTED LEAKS

Comment Number: EPA-HQ-OAR-2009-0923-0847-6
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
§ 98.232(b) and page 18643, § 98.233(s). Offshore petroleum and natural gas production in both state and federal waters: These facilities will report emissions from all 'stationary fugitive' and 'stationary vented' sources as identified in the MMS GOADS study ... "Greater specificity is needed to describe' fugitive' and 'vented' emissions. The MMS GOADS study specifically includes (1) combustion flares, (2) fugitives, (3) glycol dehydrators, (4) loading operations, (5) flashing losses, (6) mud degassing, (7) pneumatic pumps, (8) pressure/level controllers, (9)

storage tanks, and (10) cold vents. The final rule should indicate whether all of these emission sources are to be included in the emissions report.

Response: In today's final rule, the definition for equipment leaks has replaced the definition for fugitive emissions, however the definition for vented emissions has not changed. The rule's definition for equipment leaks is consistent with the use of the term in the Alternative Work Practice to Detect Leaks from Equipment for 40 CFR parts 60, 63, and 65. Today's rule has also revised the monitoring requirements for offshore production to be consistent with MMS GOADS and therefore equipment leaks, vented and flare sources included in GOADS are subject to reporting under subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1018-7
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
Pre-amble, page 30, The term "fugitive emissions" has come to be interpreted differently in various jurisdictions around the world. ·

- CAPP recommends the use of 'fugitive equipment leaks" as it is more descriptive of the emission source being targeted.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-0847-6.

Comment Number: EPA-HQ-OAR-2009-0923-1039-19
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Clarifications or Definitions are Required for Component Types and Related Survey Criteria

Vented and fugitive emissions are better defined in the Proposed Rule than in the 2009 version of Subpart W. However, consistent nomenclature is ultimately required to eliminate ambiguity, redundancy (i.e., double counting), and unnecessary confusion in rule implementation. For example, "compressor blowdown valve" is listed as a component in Table W-3 and the associated EF is more than an order of magnitude larger than any other listed. It appears that the emissions are not related to a leaking valve body or stem, but rather natural gas bypassing the valve seat, through the valve, and vented out a blowdown vent stack. Thus, the "survey point" for leak detection is the blowdown vent even though the source is a fugitive leak through an unseated valve. The Proposed Rule presumes a certain level of expertise and understanding of facility-level components, operation, and similar issues, and there is no ability for the reader to discern this point. Similar ambiguity in the Final Rule could cause significant implementation and compliance issues.

The lack of clarity regarding component names, component types, associated leak "source", and leak survey criteria for the "emission" point will result in misapplication of emission factors, survey errors, and reporting errors. INGAA recommends that clarity and definition of the source and measurement method(s) be addressed through the EF reference document discussed above. There must be clear, concise definitions and explanations within Subpart W, especially regarding differentiation among the sources and their associated emission estimation criteria.

INGAA recommends that additional clarity be added to the Final Rule. This may best be accomplished by including component definitions, source descriptions, and related leak survey criteria with citation to the EPA technical reference document discussed above. Although INGAA strongly advocates this separate document for emission factors, it is imperative that the document be available concurrent with the Final Rule because it will play an important role in compliance and implementation. INGAA offers its assistance in development and peer review of this important technical resource.

Response: The commenter has misinterpreted the intent of the rule. The emission factors in Table W-3 in the rule are for equipment leaks from components, not for venting emissions. Definitions of sources and components are located in either subpart W, or in the overarching MRR. As the placement of emissions factors in a separate reference document would not decrease the time necessary to update subpart W specific factors and references, EPA will not remove the emission factors from subpart W itself.

Comment Number: EPA-HQ-OAR-2009-0923-1082-10
Organization: MidAmerican Energy Holdings Company
Commenter:

Comment Excerpt Text:
EPA seeks comments on the use of the term “equipment leak” versus “fugitive” and “vented” as defined in the proposed supplemental rule. (page 30)

“Equipment leak” and “fugitive” can be used interchangeably. A vented emission should be characterized as intentional or unintentional operational release. The key difference between “fugitive” and “vented” is that fugitive emissions are unknown releases that must be calculated either by direct measurement or analytical methods; whereas vented emissions are generally designed into the operation of the system.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-0847-6.

Comment Number: EPA-HQ-OAR-2009-0923-1151-65
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Preamble p. 30 EPA seeks comment on the use of the term “equipment leak” versus “fugitive” and “vented” as defined in the proposed supplemental rule.

API supports the use of terms “fugitive” and “vented” to describe the non-combustion emission sources associated with oil and natural gas systems. (Please refer to earlier definition of “fugitive emissions” provided in Section III(1) of this document.) Although the term “equipment leak” is consistent with “fugitive”, it is incorrect to apply the term to “vented” emission sources.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-0847-6.

Comment Number: EPA-HQ-OAR-2009-0923-1173-2
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
EP A should define "fugitive" emissions consistent with other Clean Air Act ("CAA") regulatory programs.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-0847-6.

Comment Number: EPA-HQ-OAR-2009-0923-1173-9
Organization: Resolute Energy Corporation
Commenter: Patrick E. Flynn

Comment Excerpt Text:
Definition of Fugitive Emissions. "EPA seeks comment on the use of the term 'equipment leak' versus 'fugitive ' and 'vented' as defined in the proposed supplemental rule. " (75 FR 18613)
Resolute Comments:
EPA should define fugitive emissions in Proposed Subpart W consistent with existing rules promulgated under the CAA to avoid confusion among various regulatory programs. EPA should apply the definition of fugitive emissions already found in 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state that "fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening." For example, leaks from natural gas driven pneumatic controller and valves, pump seals, non-pneumatic pumps and connectors should all be considered fugitive emissions. The use of an additional term, such as "equipment leak," will only introduce additional confusion and increase the reporting burden without providing additional useful information to the EPA.

Response: Please see the response to comment EPA-HQ-OAR-2009-0923-0847-6.

Comment Number: EPA-HQ-OAR-2009-0923-1196-9
Organization: Independent Petroleum Association of New Mexico
Commenter: Karin V. Foster

Comment Excerpt Text:
On page 43 of the Technical Support Document and in 98.233(p)(4), the EPA addresses fugitive emissions from compressor operations at different operational modes. In the Technical Support Document, the EPA concedes that to address this issue, operators must measure emissions for each mode the compressor is operated in and the duration of that operational mode and this will “increase the reporting burden, since measurements will have to be taken at each mode of

compressor operation." Indeed – this requirement will greatly increase the reporting burden while not addressing a significant source of GHG emissions. 98.233(p)(4) requires measurement in several operational modes: Compressor engines are generally either operational or not. Some of the operational modes are not normally encountered and this would have to be artificially reproduced in the field for the sole purpose of reporting. A compressor would not standby pressurized for any amount of time that would affect its emissions significantly as it would otherwise be offset by the fact that the compressor is operational. Therefore, requiring measurement in each mode is burdensome, difficult to schedule, and does not reflect a significant source of emissions.

Response: EPA does not agree with this comment. Typically, reciprocating compressor rod packing emissions vary with the mode of operation of the compressor. The emissions are highest when the compressor is operating and lower when they are in standby pressurized mode. Rod packing seals become worn with time and then will typically leak more. Note that rod packing wear is highly variable with all compressors, even those that are the same make and model. When the compressor is not operating depressurized, there may be leakage of natural gas through the unit isolation valve, particularly if the valve seat has become fouled and will not completely close. Hence to correctly characterize annual emissions from reciprocating and centrifugal compressors, estimation of emissions in three compressor modes, operating, standby pressurized, and not operating depressurized is required. A temporary meter such as vane anemometer or permanent meter such as orifice meter can be used to measure emissions from the vents. However, EPA agrees to allow compressor venting measurement in the 'as found' mode, see response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1197-3
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

<u>Comment Excerpt Text:</u>
The ambiguity over the definitions of the several items in the proposed rule, availability of sufficient numbers of "optical imaging instruments" for leak detection of fugitive emissions, availability of trained personnel- both contractors and facility personnel- to operate the "optical imaging instrument" makes compliance with the proposed rule nearly impossible to achieve.

Response: In regard to definitions, please see the response to comment EPA-HQ-OAR-2009-0923-1039-19. In regard to difficulty with complying with the rule, EPA is allowing Best Available Monitoring Methods for certain sources and time periods, please see Section II.F of the preamble to today's final rule.

14.5 BOUNDARY ISSUES WITH SUBPART RR

Comment Number: EPA-HQ-OAR-2009-0923-1151-77
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
(Preamble p. 85) Generally, EPA has proposed that onshore production be reported at the basin level, as opposed to the unit or field level, to minimize reporting burden. EPA notes that in a concurrent proposed rulemaking for facilities that conduct CO2 injection or geologic sequestration (subpart RR), the term "facility" is defined at a more disaggregated level, specifically as a "well or group of wells." EPA seeks comment on the use of more disaggregated reporting options for subpart W.

As noted in the comments to questions W3 through W5, the API does not agree that the basin-level facility definition minimizes the reporting burden. That said, the facility definition should be consistent for Subparts W and RR, as CO2 injection is a technique used to enhance oil production, and thus some entities reporting under Subpart RR will also be reporting under Subpart W.

Response: EPA does not agree with the commenter. The proposed subparts RR and W have very different GHG sources that need to be characterized, and the facility and source category definitions have been chosen accordingly. The proposed subpart RR requires reporting from facilities that inject CO_2 underground for geologic sequestration. The proposed subpart RR uses the definition of facility in 40 CFR 98.6 and are focused on reporting quantities of CO_2 received and sequestered. On the other hand, Subpart W is primarily concerned with above surface equipment associated with the wellhead in addition to the wellhead itself. EPA considered requiring the proposed subpart RR reporting at the basin level, but concluded that data on CO_2 received and sequestered is most useful to EPA at a project level. This is because the proposed subpart RR applies to the injection of CO_2 in a variety of geologic formations beyond oil and gas fields, and basin level reporting may not be applicable in all geologic circumstances.
An EOR site permitted as Class II under the Underground Injection Control (UIC) program is required to report information on the quantities of CO_2 received and the source of CO_2. An EOR site is not required to report under the proposed subpart RR unless it chooses to opt-in to the proposed subpart RR or is permitted as Class VI under the UIC program. An EOR project reporting under the proposed subpart RR must calculate equipment leak and vented CO_2 emissions from surface equipment between the flow meters and the wellhead using calculation procedures provided in subpart W. EPA concluded such data are important in order to provide a proper accounting of the amount of CO_2 that is geologically sequestered.
Hence, EPA has chosen the facility definitions for proposed subpart RR, and W and has retained them in today's final rule.

14.6 OTHER

Comment Number: EPA-HQ-OAR-2009-0923-0847-11
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Page 18614, 2nd column, 3rd paragraph: The sentence "Extraction includes several types of processes: reservoir management, primary recovery, secondary recovery such as down-hole

pumps, water flood ... " is not quite correct as the use of down-hole pumps is not a secondary recovery process, but rather a form of artificial lift. Secondary recovery processes work with the forces in the reservoir by using methods such as water flooding and some gas injection technologies. We suggest changing the sentence to "Extraction includes several types of processes: reservoir management, primary recovery, artificial lift, such as down-hole pumps, secondary recovery such as water flood ..."

Page 18615, 3rd column, 1st paragraph: It is stated that offshore petroleum and natural gas production CO_2 and CH_4 emissions accounted for 5.1 million metric tons CO2e. In Table W-2 on page 18618 the total emissions from offshore petroleum and gas production are 11.3 million metric tons CO_2e. Please ex plain the differences. Does the first figure not include combustion?

Response: EPA agrees that clarifying its description of "extraction" to not include downhole pumps as secondary recovery would be useful to reporters. Today's final rule describes extraction to include several types of processes, "reservoir management, primary recovery, artificial lift, secondary recovery such as water flood…"

With regard to the emissions cited in the Preamble, EPA clarifies in today's final rule that there were a total of 11.3 million metric tons CO_2e emitted in 2006 by offshore petroleum and natural gas production, as was cited in Table W-2, with 5.1 million metric tons CO_2e predicted emissions coverage under subpart W at the 25,000 metric ton threshold.

Comment Number: EPA-HQ-OAR-2009-0923-0847-4
Organization: United States Department of the Interior
Commenter: Willie R. Taylor

Comment Excerpt Text:
Page 18633, 3rd column, § 98.6 Definitions. Acid Gas: The definition should read " ... the contaminants that are separated from sour natural gas by an acid gas removal unit."

Page 18634, 3rd column, Flare Combustion: The definition reads "Flare combustion means unburned hydrocarbons including CH_4, CO_2, N_2O ..." This is inaccurate as most of the emissions from the flare are combustion products. Since a flare cannot achieve 100% burn efficiency, a small percentage of the hydrocarbons (including CH_4) leave the stack without being combusted. The definition should be modified accordingly.

Response: EPA agrees that there was a grammatical error in the definition of "acid gas". For more information see response to EPA-HQ-OAR-2009-0923-1151-17.
With regard to flare combustion, EPA agrees that the definition of flare combustion emissions was confusing. In today's final rule the term has been modified to "flare stack emissions" and clarifies that it means "CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares."

Comment Number: EPA-HQ-OAR-2009-0923-1039-28
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Flare combustion definition: The Proposed Rule includes additional and revised definitions in §98.6. The definition of "flare combustion" is poorly worded because CO2 and N2O are not "unburned hydrocarbons" or products of incomplete combustion. INGAA recommends the following revision: "Flare combustion means emissions from combustion of gas in flares unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares."

Response: EPA agrees, and has revised the definition of flare emissions in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

Comment Number: EPA-HQ-OAR-2009-0923-1011-25
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Proposed Rule Section 98.6 Definition for Flare Combustion. —A revision to the proposed definition is requested for clarity and accuracy.

Response: EPA agrees, and has revised the definition of flare combustion in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

Comment Number: EPA-HQ-OAR-2009-0923-1011-54
Organization: El Paso Corporation
Commenter: Fiji George

<u>Comment Excerpt Text:</u>
Section 98.6 Definitions

Flare combustion

The definition of flare combustion is poorly worded. We suggest the following:

Flare combustion emissions means emissions of CO2 and N2O formed during the combustion process and emissions of CH_4 resulting from the incomplete combustion of gas in flares.

Onshore petroleum and natural gas production owner or operator

The proposed definition on page 18635 has an incorrect reference to 98.230(b)(2). The correct reference is 98.230(a)(2).

Response: While EPA does not agree with the commenter's suggested text, EPA has revised the definition of flare emissions; please see the response to EPA-HQ-OAR-2009-0923-0847-4.

With regard to the definition of onshore petroleum and natural gas production owner or operator, EPA agrees that it referenced the wrong paragraph, as discussed in this comment. Today's final rule references the appropriate paragraph that defines the onshore petroleum and natural gas production sector in the definition.

Comment Number: EPA-HQ-OAR-2009-0923-1018-19
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
Acid Gas – CAPP requests that the EPA modify the definition to: "means hydrogen sulfide (H2S) and/or carbon dioxide (CO2) contaminants….." This change would be consistent with the definition currently used by the sector.

Condensate – CAPP requests the EPA implement the following change to the definition of condensate: "means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure or both and remain liquid at storage conditions atmospheric conditions….."

Flare Combustion Efficiency - CAPP requests the EPA implement the following change to the definition of Flare combustion efficiency: "means the fraction of natural process gas, on a volume or mole basis……"

Response: EPA agrees, and has revised the definition of acid gas in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1151-17.

With regard to the definition of condensate, EPA disagrees that the proposed definition further clarifies what subpart W means by the term "condensate". The primary clarification sought by the commenter was that storage conditions are atmospheric. EPA disagrees that this clarification is necessary, pressurized storage of condensate is a measure to avoid emissions. Since this is a greenhouse gas emissions reporting rule, EPA only expects that emissions will be vented from atmospheric storage of condensate, thus the proposed clarification would not affect the reporting under subpart W.

With regard to the definition of flare combustion efficiency, EPA agrees that it will be less confusing to reporters to clarify the use of the term "natural gas" in the definition. In today's final rule, §98.238, the definition of flare combustion efficiency is "the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip."

Comment Number: EPA-HQ-OAR-2009-0923-1018-52
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

<u>Comment Excerpt Text:</u>
In 98.236(c)(14)(iv), the EPA requires facilities to identify the proportion of total natural gas to pure hydrocarbon stream being sent to the flare annually for the reporting period. CAPP requests clarification. Is the EPA interested in the quantity of purge gas required to ensure a continuous flame? Or is the request intended to require quantification of non-hydrocarbon components of the natural gas stream. Additionally CAPP requests a definition of total natural gas and pure hydrocarbon stream.

Response: Upon further analysis and review, EPA has determined in today's final rule that the reporters can use engineering estimates based on process knowledge and best available data and operating records to determine the amount and type of gas sent to a flare on an annual basis. This would encompass all gas sent to the flare, including purge and pilot gas as well as waste gas. The terms "total natural gas" and "pure hydrocarbon stream" are no longer used in today-'s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1019-2
Organization: Red Cedar Gathering
Commenter: Ethan W. Hinkley

<u>Comment Excerpt Text:</u>
Clarification of "Large Compressors"

EPA refers to "large compressors" in multiple places in the proposed rule. Red Cedar is requesting a definition or clarification of the term "large compressors" as it relates to this rule. Red Cedar recommends a horsepower rating of 2,000 hp and greater for the compressor driver be used to define a "large compressor".

Response: Today's final rule no longer uses the term "large compressor". This term was used in the context of onshore petroleum and natural gas production compressors to differentiate between wellhead compressors, which are typically smaller and widely dispersed, and gathering compressors which range widely in size and are often in groups of multiple compressors. Onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment compressors are much larger on average than compressors in the onshore petroleum and natural gas production segment. EPA determined that it is too burdensome for the contribution of emissions that are estimated to be released from these smaller production compressors to perform leak detection and measurement. Therefore, today's final rule requires all onshore production compressors to estimate emissions using a factor. Today's final rule also does not include gathering lines and boosting stations. For further clarification, please see Section II.F of the preamble. For other industry segments where multiple compressors are generally grouped in a facility EPA determined that leak detection and vent measurements could be accomplished cost-effectively, provided reporters spread the emissions measurements out over a three year period. For more information on selection of sources to report, please see chapter 4 of the background technical support document of the rule making docket, EPA-HQ-OAR-2009-0923).

Comment Number: EPA-HQ-OAR-2009-0923-1024-38
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Comments on Definitions. In addition to our comments on the definitions of facility types within the petroleum and natural gas sector (discussed above in section II.B.2), we also offer the following comments on other definitions in the proposed text of Subpart W:

1. Fugitive emission. EPA's proposed definition of the term "fugitive emission'[254] appears to be drawn from the agency's existing PSD regulations.[255]The stipulation in this definition that fugitive emissions only include those emissions that "could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening" is inappropriate for a rule that is focused on reporting, rather than control of emissions. In the PSD context, fugitive emissions are defined with reference to stacks, chimneys, and vents in order to require sources to capture and contain unintentional emissions wherever reasonably possible. The Mandatory Reporting Rule does not have this objective, and should not require sources in the petroleum and natural gas sector to make a judgment call as to whether a particular source could be channeled through a vent or other opening. Therefore, Kinder Morgan recommends that EPA modify the proposed definition of "fugitive emissions" to more closely reflect the usage of that term in our industry. A recommended definition appears in Appendix A of these comments.

2. Flare combustion. Kinder Morgan recommends that EPA reconsider the proposed definition of "flare combustion,"[256] which currently includes "unburned hydrocarbons including CH_4, CO_2, and N_2O." This definition is problematic because the petroleum and natural gas industry does not use the term "flare combustion" to refer to uncombusted hydrocarbons and combustion byproducts. Rather, flare combustion has a well-established definition in the industry, referring to the process of combusting gases in a flare device. EPA should either establish a separate term for "unburned hydrocarbons" or simply refer to these substances directly in the text of the rule.

3. Blowdown vent stack emissions. The proposed definition of the term "blowdown vent stack emissions"[257] refers only to releases of "natural gas," even though Subpart W calls for emissions monitoring of CO2 injection equipment that does not handle natural gas. In addition, the proposed definition includes gas "released due to maintenance," a description that is overly broad and could capture emissions that are not traditionally regarded as blowdown emissions. To address these issues, Kinder Morgan recommends that the definition, and corresponding

[254] Proposed Subpart W, 75 Fed. Reg. at 18,634.] appears to be drawn from the agency's existing PSD regulations.

[255] See 40 C.F.R. SECTION 52.21(b)(20).

[256] Proposed Subpart W, 75 Fed. Reg. 18,634.

[257] Proposed amendments to 40 C.F.R. SECTION 98.6.

quantification methodology, be clarified to include equipment in CO2 service as well as equipment handling natural gas. In addition, the definition should be revised to include gas trapped within a compressor and associated piping that is released during all start-up and shut-down procedures for that compressor, as opposed to gas released during all maintenance operations.

4. Natural gas high- and low-bleed pneumatic devices. The proposed methodologies for quantifying emissions from high and low-bleed pneumatic devices powered by pressurized natural gas refer to "continuous bleed" devices,[258] yet the definitions of high- and low-bleed pneumatic devices do not.[259] To avoid confusion, Kinder Morgan requests that EPA clarify the definitions of high- and low-bleed pneumatic devices to refer only to devices with a continuous bleed function, as opposed to intermittent bleed function.

5. Definition of Transmission Pipelines. EPA should omit the adjective "crosscountry" in its definition of transmission pipelines, since not all transmission pipelines subject to Subpart W cross the country or even cross state lines.

Response: EPA disagrees that it must define the term "fugitive emission" so that it does not stipulate that the emissions could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. One practical example from subpart W is that through-valve leakage from compressor unit and blowdown valves may be manifolded into a vent stack and are covered under a different methodology than equipment leaks and emission factors. EPA does not anticipate that reporters will be unable to determine what emissions are considered to be equipment leaks by this definition and it serves a purpose, as stated, under subpart W. In addition, EPA has replaced the term "fugitive emissions" with "equipment leaks." This change was made to ensure consistency with the terminology in the Alternative Work Practice to Detect Leaks from Equipment for 40 CFR parts 60, 63, and 65.

EPA agrees, and has revised the definition of flare combustion in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

EPA agrees that it would be less confusing to reporters to clarify the definition of blowdown vent stacks to include CO_2 as well as natural gas. Today's final rule applies to all blowdown events, not only maintenance shutdowns, and specifies calculating the volume of all equipment, piping and vessels between isolation valves adjusted to standard cubic feet based on actual pressure and temperature before blowdown. Also, blowdown events that are less than 50 standard cubic feet need not be reported to reduce burden and uncertainty in small blowdowns such as level sight glasses, instrument leads, etc.

EPA has considered commenters' suggestions regarding characterization of pneumatic devices and has agreed to prescribe the use of emission factors provided in GRI and the API Compendium. As a result, today's final rule requires counting pneumatic devices that are

[258] See Proposed 40 C.F.R. SECTION 98.233(a)(1)(ii), (b).

[259] Proposed Subpart W, 75 Fed. Reg. at 18,635.

continuous high-bleed, continuous low-bleed, and intermittent bleed, and applying emission factors for each type.

EPA agrees that it is less confusing to reporters to clarify the definition of transmission pipelines to include those that are not cross country. Today's final rule includes both interstate and intrastate pipelines in the definition.

Comment Number: EPA-HQ-OAR-2009-0923-1027-3
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.6 Definitions: There is no definition for "Offshore petroleum and natural gas production owner or operator," as there is for "Onshore petroleum and natural gas owner or operator."

OOC Comment: See comment re: 98.3(c)(11) above. Due to the complexities of offshore facility ownership and operatorship, we feel a definition is warranted. A facility can have multiple owners and operators, and the number of fields and wells with multiple owners that tie back to the facility can further complicate who reports what to the EPA. We feel the EPA should define the offshore facility owner/operators in a manner similar to that of the onshore definition, where facilities with multiple owners/operators are instructed to designate one entity to report all emissions from the joint facility, and where production handling from fields not apply to the definition of facility ownership.

Response: EPA disagrees that it has not adequately defined who must report for offshore petroleum and natural gas production facilities covered under subpart W. Today's final rule instructs reporters to use the methodology set forth by the most recent Gulfwide Emission Inventory Study (often referred to by its activity collection portion, "GOADS", by industry). In following this methodology, owners and operators will determine who reports the same as they would under the MMS regulation. For non-GOADS reporting platforms, including state waters and state and federal waters outside the Gulf of Mexico, please refer to Section V of the preamble to The Final Mandatory GHG Reporting Rule ("Final MRR"), (40 CFR part 98), and Section II.F of the preamble to today's final rule, for the "designated representative" who must certify the emissions inventory report. The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-1027-4
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
98.6 Definitions: Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (…) and released with methane and other light hydrocarbons to the

atmosphere or a flare.

OOC Comment: There should be a separate definition for Acid gas removal flare stack, as defining vent stack emissions as including flare emissions may create confusion.

98.6 Definitions: Dehydrator vent stack emissions means natural gas released from a natural gas dehydrator system…

OOC Comment: Several dehydrator systems release the natural gas back into the process rather than directly to the atmosphere. There should be mention that the natural gas is released to the atmosphere.

Response: EPA disagrees that it should define acid gas removal flare stacks separately from vent stacks. Whether the AGR stack leads directly to the atmosphere or is routed to a flare system does not affect the methodology to determine the volume of CO_2 only emitted to the atmosphere. Reporters must use this methodology to determine the volume passing through the AGR stack, then if it is vented to the atmosphere, that value is reported as an emission, if it is passed to a flare system, the methodology accounts for the CO_2 that passes unchanged through the flare to the atmosphere, not counting any hydrocarbon component of the AGR vent nor other hydrocarbons sent to the flare.

EPA disagrees that it must caveat the term dehydrator vent stack to only mean natural gas that is released to the atmosphere. The commenter suggests that for some natural gas dehydration systems, the gas that would be vented is captured and injected back into the process. Since this is not a release of gas, EPA does not deem it necessary to caveat the definition.

Comment Number: EPA-HQ-OAR-2009-0923-1027-5
Organization: Offshore Operators Committee
Commenter: Allen Verret

Comment Excerpt Text:
Section 98.230(a)(1): Offshore petroleum and natural gas production. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

OOC Comment: The rule should clearly state that it does not apply to offshore drilling facilities unless they are included by GOADS. The category description does not include facilities engaged only in drilling (for example, Mobile Offshore Drilling Units or MODU’s) since, in contrast to production platforms, their primary purpose is not extracting and transferring hydrocarbons. Similarly, GOADS 2008 guidance only included drilling activities in cases of platform rig applications or jack-up rigs associated with an Area/Block with existing production structures. Thus, the rule should clearly state that drilling activities are not included or point to

GOADS to determine which ones are. If MODU's were to be included, it should be the MODU owner/operator who does the reporting.

Response: EPA agrees, and has clarified today's final rule. Offshore drilling and exploration conducted on a production platform are included in subpart W. Subpart W does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

Comment Number: EPA-HQ-OAR-2009-0923-1040-12
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The: Condensate definition states that it includes both water and hydrocarbon liquids. Although a condensate storage tank in a production field typically includes both water and condensate, the IWO separate into different phases and are removed from the tank as separate streams. The tank operator documents the condensate production volume as the condensate phase that is removed from the tank. It is not accurate to state that condensate includes water, and we request that EPA remove "water" from the "condensate" definition.

Response: EPA disagrees that it should remove water from the condensate definition. EPA's intent is to collect emissions data from storage tanks immediately downstream of multi-phase separators such as pressurized gas-liquids separators at well production sites and scrubbers at the inlet of compressor stations. These are targeted because previous studies have identified that the separator dump valves in some cases malfunction, allowing gas to vent through the storage tank, and in the case of production separators, significant volumes of gas flash out of solution with the hydrocarbon phase in the atmospheric tank. Because the liquids collected in storage tanks from these separators may contain substantial volumes of water, and particularly the case in tanks collecting condensed water from transmission scrubbers, EPA specifically included water in the definition of condensate to capture the emission sources.

Comment Number: EPA-HQ-OAR-2009-0923-1040-13
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The Conventional Wells definition stales that they do not employ hydraulic fracturing. "Conventional" gas reservoirs are typically underground formations composed of sandstone, limestone, dolomite, and/or mixed mineralogy, and "conventional" wells are those that produce from these types of reservoirs. The term "conventional" does not necessarily consider whether the formation has been hydraulically fractured. Many of the "conventional'" and "unconventional" wells in the United States have been hydraulically fractured. We request that EPA define the terms "conventional wells" and "unconventional wells" based on the well's reservoir type, as opposed to whether the well operates in a fractured reservoir.

Alternatively, the rule could omit the terms "conventional" and "unconventional" and replace these terms where needed with a reference to fracturing. So, for example, the emission calculation methodology section could be retitled from “Gas well venting during unconventional well completions and workovers" to "Gas well venting for hydraulically fractured well completions and workovers."

Response: EPA agrees that its characterization of conventional and unconventional well completions and workovers did not directly address the reasons for the separate monitoring methods. Today’s final rule no longer uses the language of conventional or unconventional wells, but instead refers to well completions and workovers with hydraulic fracture and those without hydraulic fracture.

Comment Number: EPA-HQ-OAR-2009-0923-1040-16
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The Unconventional Wells definition states that they are wells that employ hydraulic fracturing. The term "unconventional" applies to wells that produce from reservoirs that are not "conventional," most often coal beds and shales. In addition, the term "unconventional” typically refers to wells that produce from tight formations with a permeability less than 0.1 milli-Darcies. The term "unconventional" does not necessarily consider whether a reservoir has been hydraulically fractured. Many of the "conventional-' and '"unconventional" wells in the United States have been fractured. We request that EPA define the terms "conventional wells" and “unconventional wells" based on the well's reservoir type, as opposed to whether the well operates in a fractured reservoir.

Response: EPA does not agree with this comment. The terms “conventional” and “unconventional” are no longer used in today’s final rule, replacing unconventional with hydraulic fractured. Please see the response to EPA-HQ-OAR-2009-0923-1040-13.

Comment Number: EPA-HQ-OAR-2009-0923-1040-14
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The Gas to Oil Ratio (GOR) definition states that it is the ratio of the volume of gas at standard temperature and pressure produced from a volume of oil when depressurized to standard temperature and pressure. The oil and gas industry does not typically measure GOR in this manner. GOR is usually expressed as the measured natural gas volume that separates at actual separator temperature and pressure (corrected to standard temperature and pressure) divided by the measured oil volume from the storage tank(s). We request that EPA modify the GOR definition to accurately reflect the current industry-accepted method.

Response: EPA disagrees with this comment, but has revised today's final rule methods in 98.233(l) and 98.233(m), such that reporters can use existing data, an appropriate standard method published by a consensus-based standards organization, or an industry standard practice to determine GOR. Thus, the method of determining GOR will coincide with industry's typical measurement. However, for the purposes of reporting to subpart W, all emissions must be converted to standard conditions. Thus, reporters must convert the measured GOR to standard volume per liquid barrel or convert actual emissions estimated using GOR to standard conditions for reporting (both are mathematically equivalent).

Comment Number: EPA-HQ-OAR-2009-0923-1040-15
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The Reservoir definition states that it is characterized by a single natural gas pressure system. This statement is not accurate because a reservoir can have multiple pressure systems that are separate pods with permeability barriers between them. We request that EPA remove the last sentence from this definition.

Response: EPA agrees, and today's final rule deletes the reference to "a single natural gas pressure system". This term "reservoir" is not used in any calculation methodology or reporting requirement in today's final rule. This term is simply a descriptor used, for example, in describing underground gas storage in a "depleted gas or oil reservoir" or enhanced oil recovery in a "crude oil reservoir."

Comment Number: EPA-HQ-OAR-2009-0923-1040-17
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

Comment Excerpt Text:
The Well Completions definition states that it is a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This definition is not accurate. The term "well completion" typically refers to the process of connecting the well bore to the reservoir. It may include treating the formation or installing tubing, packer(s), or lifting equipment. We request that EPA modify the "well completions" definition to reflect the description given here.

Response: EPA disagrees that the definition of well completion is not accurate. EPA understands that installing tubing, packer(s), or lifting equipment may also accompany connecting the well bore to the reservoir; however, a well is not completed until the well bore is connected to the reservoir, so subpart W will not miss any completions. In addition, if lifting equipment is installed or maintenance is performed on a well already producing, then that is considered a workover for the purposes of this rule.

Comment Number: EPA-HQ-OAR-2009-0923-1040-18
Organization: American Exploration & Production Council
Commenter: V. Bruce Thompson

<u>Comment Excerpt Text:</u>
The Well Workover definition states: "This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop open new fractures in existing low permeability gas reservoirs." We request that EPA modify this sentence to read, "This process may also include high-rate flowback of injected gas, water, oil and sand used to fracture or refracture and prop open new fractures in existing lower permeability gas reservoirs."

Response: In today's final rule, EPA incorporated the language "this process also includes high-rate flowback of injected gas, water, oil and proppant used to fracture or re-fracture and prop-open new fractures in existing low permeability gas reservoirs …"

Comment Number: EPA-HQ-OAR-2009-0923-1042-4
Organization: ConocoPhillips Company
Commenter: Dan F. Hunter

<u>Comment Excerpt Text:</u>
EPA proposed definition: Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

ConocoPhillips Comment:

Modify the definition as follows: "Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of recovered carbon dioxide into a crude oil reservoir to enhance the recovery of oil."

The purpose of this requested change is to acknowledge that some oil production fields re-inject, into the reservoir, the natural gas that is produced with the oil. This natural gas has some small quantity of naturally occurring CO_2 in it and is not injected for the purposes of enhanced oil recovery.

Response: EPA disagrees that the suggested revision is necessary to clarify the definition of enhanced oil recovery subject to subpart W. EPA is requiring reporting of only the critical phase CO_2 operations associated with EOR, and recognizes that there are other operations designated as enhanced oil recovery which are not subject to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1058-5
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
Flare combustion
Title of this definition should be expanded to “Flare combustion emissions” as it more accurately represents the gasses represented in the subpart.

Response: EPA agrees, and, in today’s final rule, EPA has revised the term flare combustion. Today’s final rule uses the term flare stack emissions, please see the response to EPA-HQ-OAR-2009-0923-0847-4.

Comment Number: EPA-HQ-OAR-2009-0923-1058-6
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
High-Bleed Pneumatic Devices
Pneumatic devices in the oil and gas field are also powered by compressed air. This definition should specify that devices powered by natural gas or gas containing reportable compounds are included in this rule or change the defined word to “natural gas driven high-bleed pneumatic devices”.

Response: EPA disagrees that it is necessary to change the term high-bleed pneumatic device to natural gas driven high-bleed pneumatic device. The definition states for subpart W that the covered devices are powered by pressurized natural gas and the methodology in today’s final rule states that it is for natural gas pneumatic devices. EPA does not anticipate that any reporter will confuse the source or monitoring methods to apply to air-driven devices.

Comment Number: EPA-HQ-OAR-2009-0923-1058-7
Organization: Colorado Oil and Gas Association
Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
Low-Bleed Pneumatic Devices
Pneumatic devices in the oil and gas field are also powered by compressed air. This definition should specify that devices powered by natural gas or gas containing reportable compounds are included in this rule or change the defined word to “natural gas driven high-bleed pneumatic devices”.

Response: EPA disagrees that it is necessary to change the term low-bleed pneumatic device to natural gas driven low-bleed pneumatic device. Please see the response to EPA-HQ-OAR-2009-0923-1058-6.

Comment Number: EPA-HQ-OAR-2009-0923-1060-14
Organization: Yates Petroleum Corporation
Commenter:

Comment Excerpt Text:
General Comments – Clarification of Definitions

Yates believes the following terms require clarification or definition in the rule:

98.232(c)(9): Gathering pipeline fugitives. Yates Petroleum Corporation believes that it is unclear when Production is required to include gathering, and when boosting/processing includes gathering. Yates Petroleum Corporation reiterates that it is unclear in the rule where Production site responsibility ends and Gathering/Processing site responsibility begins.

98.232(i)(2): Below ground meter regulators and vault fugitives. It is unclear in the supporting documentation why EPA is requiring below-ground fugitives.

98.232(j): Flares. Yates Petroleum Corporation believes that the EPA needs to clarify the definition of this emission source. Are enclosed flares or fireboxes included in this source category?

98.233(a)(1)(ii): Calculate the natural gas emissions for each continuous bleed device using Equation W-1 of this section. EPA should define "continuous."

98.233(g)(ii)(C): Gas well venting during unconventional well completions and workovers. The term "producing field" in this subpart is not defined.

98.230(a)(3): Onshore Natural Gas Processing Plant Source Definition. In NSPS KKK, a natural gas processing plant is defined as, "any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products." EPA's treatment of onshore natural gas processing plants does not appear to align with the NSPS KKK definition of "natural gas facility." For purposes of applicability, a gathering/boosting station without gas processing is not subject to the requirements of KKK. Therefore, a gathering/boosting station that is not owned by a processing plant should not be considered part of that processing plant facility.

Response: With regard to gathering pipeline equipment leaks, EPA is not requiring the monitoring and reporting of emissions from gathering and boosting equipment at this time. Please see the discussion in Section II.F of the preamble to today's final rule for more information.
Regarding the process it used to determine a methodology for below ground metering and regulator stations, see detailed discussion of its general methodology and reasoning for

including this source in chapter 4.c of the background technical support document in the rule making docket (EPA-HQ-OAR-2009-0923).
EPA has reviewed this comment and notes that the flare source in today's final rule does not include enclosed flares (e.g. incinerators) or the firebox of enclosed thermal oxidation units. For further details, please see the response to EPA-HQ-OAR-2009-0923-1015-31.
EPA agrees with the comment. For a clarification on the meaning of "continuous," please see the response to EPA-HQ-OAR-2009-0923-1060-28.

EPA has defined the term "field" in the rule and a producing field simply means a field that has any production in the reporting period.

Comment Number: EPA-HQ-OAR-2009-0923-1061-4
Organization: Texas Pipeline Association
Commenter: Patrick J. Nugent

Comment Excerpt Text:
Certain definitions in the proposed rule should be amended. Proposed § 98.6
defines "flare combustion" to mean "unburned hydrocarbons including CH_4, CO_2, N_2O emissions resulting from the incomplete combustion of gas in flares." This definition is somewhat peculiar in that it includes CO_2 and N_2O which in fact are products of combustion, rather than the result of non-combustion. Hence, TPA asks EPA to review this list and consider eliminating CO2 and N_2O.
In addition, TPA suggests that the definition of "flare combustion efficiency" be amended as follows:
"the hydrocarbon fraction of [strike through: natural gas] waste stream, on a volume or mole basis, that is combusted at the flare burner tip."

Response: EPA agrees, and has revised the definition of flare combustion in today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

With regard to the definition of flare combustion efficiency, EPA agrees that it will be less confusing to reporters to clarify the use of the term "natural gas" in the definition. In today's final rule, the definition of flare combustion efficiency is "the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip."

Comment Number: EPA-HQ-OAR-2009-0923-1069-1
Organization:
Commenter: Michael Leonard

Comment Excerpt Text:
((98.230 (2)) Onshore petroleum and natural gas production includes the verbiage all EOR operations using CO2. We propose that EOR operations using CO2 be defined with facility definitions and that facility definitions are consistent with the reporting requirements of other facilities. The current statement could be interpreted such that all wellsites, test sites and

processing facilities would be grouped into one large facility under the definition of a production facility. This would cause unnecessary reporting burden on companies practicing Enhanced Oil Recovery that would be inconsistent with the reporting burden of natural gas facilities

Response: EPA disagrees that EOR operations should be identified with an individual facility definition. EPA views EOR simply as an operating practice in crude oil production involving certain unique processes and stream compositions. Today's final rule has been clarified in 98.232(c) that in onshore production GHG emissions from sources of EOR injection pump blowdown and EOR hydrocarbons liquids dissolved CO_2 are included in subpart W.

Comment Number: EPA-HQ-OAR-2009-0923-1074-20
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Comment on 98.6: Definitions

Condensate

Current air quality permitting programs have more specific definitions of condensate to prevent a production water tank from being defined as a condensate storage tank.

Revision: "Condensate means hydrocarbon liquids that remain liquid at standard conditions (68 degrees Fahrenheit and 29.92 inches Mercury) and are formed by condensation from, or produced with, natural gas, and which have an American Petroleum Institute gravity ("API gravity") of 40 degrees or greater."

Response: EPA disagrees that it should eliminate water from the definition of condensate. For more information, see the response to EPA-HQ-OAR-2009-0923-1040-12.

Comment Number: EPA-HQ-OAR-2009-0923-1074-21
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Flare Combustion

CO2 and N2O are not "unburned hydrocarbons" or products of incomplete combustion

Revision: "Flare combustion means the burning of hydrocarbons and flammable gases in flares."

Response: EPA agrees that the definition of flare combustion emissions was confusing. In today's final rule the term has been modified to "flare stack emissions" and clarifies that it means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

Comment Number: EPA-HQ-OAR-2009-0923-1074-22
Organization: WBI HOLDINGS
Commenter:

<u>Comment Excerpt Text:</u>
Gas to oil ratio (GOR)

Revision for clarification.

Revision: "The gas/oil ratio (GOR) is the ratio of the volume of gas that comes out of solution, to the volume of oil at standard conditions."

Response: EPA revised the final rule methods using GOR in 98.233(l) and 98.233(m). Please see the response to EPA-HQ-OAR-2009-0923-1040-14.

Comment Number: EPA-HQ-OAR-2009-0923-1099-4
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

<u>Comment Excerpt Text:</u>
Optical Gas Imaging Instrument
Section 98.234 requires the use of an "optical gas imaging instrument" for annual leak surveys. This is an undefined term.

Response: EPA disagrees that the term optical gas imaging instrument is insufficiently described for reporters to be able to comply with subpart W. Please see the response to EPA-HQ-OAR-2009-0923-0049-2.

Comment Number: EPA-HQ-OAR-2009-0923-1151-112
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
In addition, the requirements appear to target continuous bleed pneumatic controllers, as defined in Section 98.7. The definition for High-Bleed Pneumatic Devices should be modified as follows: High-Bleed Pneumatic Devices Controllers are automated “continuous bleed” flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator or other process controller. High-bleed controllers where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Response: Today's final rule clarifies the definitions of pneumatic devices as continuous high-bleed, continuous low-bleed, and intermittent.

Comment Number: EPA-HQ-OAR-2009-0923-1151-114
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
The definition for Low-Bleed Pneumatic Devices should be modified as follows:

Low-Bleed Pneumatic ~~Devices~~ Controllers mean *pilot operated* automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. ~~Part of~~ *On actuation*, the gas power stream which is regulated by the process condition flows to a valve actuator *or other process* controller. *On de-actuation, the gas power stream used to actuate the process controller* ~~where it~~ vents (bleeds) to the atmosphere. *Although the amount of gas vented at pilot operated controllers depends on the amount of power gas used for actuation, the typical rate is* ~~at a rate~~ equal to or less than six standard cubic feet per hour.

Response: Please see the response to EPA-HQ-OAR-2009-0923-1151-112.

Comment Number: EPA-HQ-OAR-2009-0923-1151-17
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.6 Definitions

Acid Gas means hydrogen sulfide (H2S) and carbon dioxide (CO2) contaminants that are separated from sour natural gas by an acid gas removal.

The word "unit" is missing from the end of the definition. API requests replacing the EPA definition with the following: "The hydrogen sulfide and/or carbon dioxide contained in or extracted from gas or other streams" (from Gas Processors Suppliers Association).

Acid Gas Removal Vent Stack Emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

The definition only mentions CH_4 emissions, omitting CO_2 emissions from this source. This is inconsistent with the requirements to report CO_2 emissions and not CH_4 emissions under Section 98.233(d).

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

API requests the following changes to this definition: “A flare in which air is blown into the base of a flare stack to induce complete combustion.” Remove, “of low Btu natural gas (i.e. high noncombustible component content.)” It is unnecessary to include the Btu content of the gas stream being burned in the flare. At times high Btu gas could be burned in an air injected flare to provide enough oxygen to promote complete combustion.

Blowdown vent stack emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and emergency shut-down (ESD) system testing.

This definition of a blowdown vent stack emissions seems to exclude compressors in CO2 service. This exclusion is most likely an oversight. Also this definition might wrongly include emissions that are not traditionally considered blowdown emissions by broadly applying the definition to all emissions released due to maintenance activities. Blowdown emissions are specific and the definition should be more precise as in the example below.

Blowdown vent stack emissions means natural gas or carbon dioxide trapped within a compressor and associated piping that is released during start-up and shut down procedures for that compressor.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.
Modify the definition as follows: “Compressor means any machine for raising the pressure of natural gas *or CO2* by drawing in low pressure natural gas *or CO2* and discharging significantly higher pressure natural gas *or CO2*”

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

API requests the following alternative definition: “Liquid formed by the condensation of a liquid or gas; specifically, the hydrocarbon liquid separated from natural gas because of changes in temperature and pressure when the gas from the reservoir was delivered to the surface separators. Such condensate remains liquid at atmospheric temperature and pressure.”

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

API requests the definition be revised to clarify emissions from the dehydrator to the atmosphere or a flare are subject to the rule but not emissions routed back to the process. API recommends the definition be revised to state “…natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerated to the atmosphere or a flare, including…”

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

This definition combines two entirely different types of gas drying. Separate definitions should be provided for the two types of desiccant material used for dehydration in the oil and gas sector.

One is the mole-sieve type desiccant system that uses alumina, silica, etc., where the wet gas is passed through and the water is adsorbed onto the surface of the desiccant materials. Once loaded, the beds are regenerated by passing hot gas through them to drive the water out. Generally, a plant/facility will have at least two sets of mole sieve type vessels so one can be in service and one in regeneration or cooling in preparation for switching beds. Unless the facility is using hot nitrogen for regeneration, the medium is generally hot gas and is recycled back to the inlet of the plant. This type lasts for many years before the beads have to be replaced.

The second is a deliquescent (sacrificial) desiccant type that uses pelletized salts like calcium chloride or lithium chloride. They work by the hygroscopic salt attracting the water and being dissolved to a saturated brine. These are the type that must be opened for replacement/replenishment of the desiccant.

The two new definitions that should be provided for deliquescent and mole sieve desiccant are as follows:

Desiccant - deliquescent means a hydro-phillic salt material used in solid-bed dehydrators to remove water from raw natural gas by adsorption and dissolving the salt into a brine. Deliquescent desiccants include, but are not limited to, pelletized calcium chloride or lithium chloride. Wet natural gas is passed through a bed of the granular or pelletized material where water is adsorbed onto the desiccant material and dissolves it into a brine, leaving the dry gas to exit the contactor. When the majority of the salt material is dissolved, the dehydrator vessel must be opened and the salt replenished.

Desiccant - mole sieve means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include, but are not limited to, activated alumina and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Almost all the water passing through the entire desiccant bed is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor. When the adsorption media is water loaded it is regenerated by passing hot gas through the media to dry it and prepare it for subsequent use. The regeneration gas is typically captured and recycled into the process for hydrocarbon gas or vented if nitrogen is used for regeneration. Mole sieve desiccants have a long life and typically are not replaced on a frequent schedule.

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

Modify the definition as follows: “Dehydrator means a device in which a liquid absorbent (including but not limited to ~~desiccant~~, ethylene glycol, diethylene glycol, or triethylene glycol) *or desiccant* directly contacts a natural gas stream to absorb water vapor.

Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Modify the definition as follows: “Enhanced Oil Recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.”

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

The preamble notes that EPA proposes to incorporate by reference the American Association of Petroleum Geologists (AAPG) Committee on Statistics of Drilling (CSD) Geologic Code Provinces Code Map, not the EIA Field Code Master List.

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

The definition of flare combustion does not appear to make sense. It seems the term should be “flare combustion emissions” not just “flare combustion.” Also unburned hydrocarbons are only part of the resulting emissions, as NO_x, CO, and SO_x emissions are also emitted. Modify the definition as follows: “Flare combustion emissions means unburned hydrocarbon emissions, including CH_4, resulting from the incomplete combustion of gas in flares along with CO_2 and N_2O formed in the combustion process.”

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

Suggest an alternative definition: “means the fraction of carbon in the flared stream, on a volume or molar basis, that oxidizes to CO2 through combustion.”

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

This differs from existing federal rules such as 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state “Fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.” The fugitive emissions definition should not result in an expansion of the current CAA regulatory definition of fugitive emissions by including the phrase "unintentional" emissions.

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

API requests that the definition state “Compressors on an individual well site, with single or multiple wells, and serving only the wells on the same site are excluded from this definition.”

New Definition: Gas well: A well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil (from the Energy Information Administration).

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

This definition implies the "high-bleed" pneumatic device and the controller are different things, when in actuality the "high-bleed" pneumatic device/controller and the valve actuator are different devices. In addition, the correct term for these devices is pneumatic controllers. The definition should also be clarified that it is intended to include only continuous bleed devices, as described in Section 98.233(a). The following revisions are suggested:

“High-Bleed Pneumatic ~~Devices~~ *Controllers* are automated *"continuous bleed"* flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator *or other process* controller. High-bleed controllers ~~where it~~ vents (bleed~~s~~) to the atmosphere at a rate in excess of six standard cubic feet per hour.”

Low-Bleed Pneumatic Devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour. The definition should be clarified that it is intended to include only continuous bleed devices, as defined in Section 98.233(b). The following revisions are suggested:

Low-Bleed Pneumatic ~~Devices~~ *Controllers* mean *pilot operated* automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. ~~Part of~~ *On actuation*, the gas power stream which is regulated by the process condition, flows to a valve actuator *or other process* controller. On de-actuation, the gas power stream used to actuate the process controller ~~where it~~ vents (bleeds) to the atmosphere. *Although the amount of gas vented at pilot operated controllers depends on the amount of power gas used for actuation the typical rate is* ~~at a rate~~ equal to or less than six standard cubic feet per hour.

New Definition: Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations, that physically deliver natural gas to end users. This category excludes infrastructure and pipelines delivering natural gas directly to major industrial users upstream of the local distribution company inlet and "farm taps" upstream of the local distribution company inlet.

New Definition: Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir (from the Energy Information Administration).

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

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

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

Modify the definition as follows: "Re-condenser means heat exchangers that cool compressed boil-off gas *from LNG* to a temperature that will condense natural gas to a liquid."

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

Modify the definition as follows: "Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or *by* custody transfer ~~meter~~ tank gaug*ing*."

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

API requests that EPA clarify that this definition only applies to this rule.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Modify the definition as follows: "Turbine meter means a flow meter in which a gas or liquid flow rate through the ~~calibrated tube~~ *meter* spins a turbine from which the spin rate is detected and ~~calibrated to measure~~ *converted to* the fluid flow rate. *Turbine meters are typically factory calibrated and can only be field calibrated by use of a "proving meter" approach."*

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

Modify the definition as follows: "Well workover means the performance of operations on producing oil and gas wells to increase production."

Response: EPA agrees and has revised today's final rule definition of acid gas by inserting "unit" and referring to "hydrogen sulfide and/or carbon dioxide." .

EPA disagrees that the definition of acid gas removal vent emissions does not already include CO_2. The definition states that it is vented "acid gas" in addition to "methane and other light hydrocarbons". Acid gas is defined as "hydrogen sulfide and/or carbon dioxide…" in the rule. EPA agrees with the suggested clarification to the terms air-injected flare and compressor. Today's final rule reflects these clarifications.

EPA agrees that it is clearer for reporters to revise the definition of blowdown vent stack emissions to include CO_2. Additionally, EPA disagrees that specifying compressor blowdown activities for start up and shutdown activities will encompass the desired blowdown activities. Please see the response to EPA-HQ-OAR-2009-0923-1024-38.

EPA disagrees with the proposed changes to the definition of condensate; please see the response to EPA-HQ-OAR-2009-0923-1018-19.

EPA disagrees that it is not clear in the current definition of dehydrator vent that gas which is captured and recycled back into the system is not included in reporting under subpart W. Please see the response to EPA-HQ-OAR-2009-0923-1027-4.

EPA did not intend to include mole sieve dehydration. For further details, please see the response to EPA-HQ-OAR-2009-0923-1305-12.

With regard to the definition of enhanced oil recovery, the commenter suggested the exact same definition, verbatim, that is currently in the rule.

EPA disagrees that the commenter's proposed alternative definition to flare combustion clarifies the term better for the purposes of subpart W. Please see the response to EPA-HQ-OAR-2009-0923-0847-4. However, EPA does agree that the definition provided in the proposed rule could be improved, and today's final rule defines flare combustion efficiency as the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

EPA agrees that it should alter the definition of fugitive emissions to not include the term "unintentional" to conform to the definition in other rules. EPA has partially addressed this issue by replacing the term "fugitive emission" with "equipment leak" in today's final rule, excluding the term "unintentional" from the definition.

With regard to the definition of gathering and boosting stations, EPA has decided not to include gathering and boosting equipment at this time. For more information, please see Section II.F of the preamble to today's final rule.

EPA agrees, and has revised today's final rule in 98.230 to clarify that farm taps are not included in the definition of natural gas distribution under subpart W. Please see the response to EPA-HQ-OAR-2009-0923-1016-24.

EPA agrees, and has revised the rule to include definitions for gas well and oil well in 98.238. EPA disagrees with the comments on "onshore petroleum and natural gas production owner or operator." However EPA has revised this definition in today's final rule in 98.238.
With regard to the proposed definition changes to high-bleed and low-bleed pneumatic devices, EPA has altered the way in which pneumatic devices are defined. Please see the response to EPA-HQ-OAR-2009-0923-1024-38.

EPA does not consider the suggested changes to the definition of re-condenser or turbine meter to be substantially different or clarified over what is already in subpart W; and thus, disagrees that the changes are necessary.

EPA agrees, and has revised today's final rule to strike the term "meter" from the phrase "custody transfer meter tank gauge" in the definition of sales oil.

EPA disagrees that it must clarify that the definition of sour natural gas applies only to this rule as the definition of sour gas is in 98.6 and therefore applies to the entire MRR.

EPA disagrees that the simplified definition of well workover proposed by the commenter provides a useful clarification for reporters. EPA has determined that its more detailed description provides a clearer understanding of the activities that are included as a well workover.

Comment Number: EPA-HQ-OAR-2009-0923-1151-24
Organization: American Petroleum Institute
Commenter: Karin Ritter

__**Comment Excerpt Text:**__
Section 98.231(b) Reporting threshold. The term “wellhead” should be clarified to specifically refer to “production wellhead”. Natural gas storage fields have wellheads and there is no indication throughout the subpart that EPA intended this for storage wellheads.

Response: EPA disagrees that changing the term “wellhead” to “production wellhead” will provide any practical clarification to subpart W. Additionally, since storage wellheads are covered in underground storage, EPA is referring to both types of wellheads. However, today’s final rule clarifies that stationary or portable combustion emissions be reported under subpart W from onshore production and natural gas distribution.

Comment Number: EPA-HQ-OAR-2009-0923-1155-30
Organization: Clean Air Task Force et. al.
Commenter: Pamela Campos

__**Comment Excerpt Text:**__
Definitions

The definition for “fugitive emissions” at § 98.6 should exclude the term “unintentional” because not all fugitive emissions are unintentionally emitted. For example, known leaking valves that are not repaired are intentional emission sources.

The definitions for “conventional wells” and “unconventional wells” at § 98.6 should be revised to be consistent with industry terminology. For example, unconventional wells may include tight sands, coalbed methane and gas shale production, oil shales, tar sands, etc. The use of fracture treatment is not the only determinant of whether a well is conventional or unconventional. It is our expectation that all types of petroleum development, both conventional and unconventional, will be covered under Subpart W, and the definitions should reflect that expectation.
The definition of the “offshore petroleum and natural gas production” source category at § 98.230 should be revised to eliminate the clause “affixed temporarily or permanently to the offshore submerged lands.” All GHG emissions generated from offshore petroleum and natural gas production activities should be accounted for and reported. This should not just be limited to the period of time a rig is anchored in place.

Response: EPA has revised the definition of fugitive emissions to “equipment leaks.” Please see the response to EPA-HQ-OAR-2009-0923-1151-17.
With regard to the definitions for conventional and unconventional wells, EPA agrees with this comment has revised the definitions Please see the response to EPA-HQ-OAR-2009-0923-1040-13.

EPA does not agree to extend reporting under subpart W to mobile drilling rigs in offshore production. See response to comment EPA-HQ-OAR-2009-0923-1201-17 for additional information.

Comment Number: EPA-HQ-OAR-2009-0923-1200-4
Organization: The Dow Chemical Company
Commenter: Robert Rouse

Comment Excerpt Text:
EPA Should Clearly Define the Term "Leaker" in the Final Rule.

Dow comments that EPA should clearly define the term "Leaker" in the final rule. EPA should define the term if one uses an optical gas imaging instrument and should also define the term if one uses an OVA/TVA as suggested in the comment above. Dow comments that the definition of leaker should be a concentration above 10,000 ppmv if measured by an OVA/TVA. A level of 10,000 ppmv is consistent with the level used in the Clearstone study to determine "leakers" and "non-leakers".

Response: EPA agrees that it should state what constitutes a “leak” using each of the detection alternatives it now allows. Today’s final rule clarifies that any leak that can be seen through an optical gas imaging instrument is considered a leak, and for Method 21 leak detection instruments, it conforms to the definition of leak provided in Method 21. For more information on the alternatives methods of leak detection, please see Section II.F of the preamble to today’s final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1206-29
Organization: Gas Processors Association
Commenter: Jeff Applekamp

Comment Excerpt Text:
The Dehydrator Vent Stack Emissions definition states that it includes the motive natural gas used by the circulation pump. The natural gas employed and expelled by a circulation pump does not vent through the dehydrator vent stack; therefore, it is not accurate to group this stream with the emissions from the dehydrator still vent. In addition, natural gas driven pneumatic pump venting is a distinct source type that Subpart W addresses separately from dehydrator vent stacks. We request that EPA remove circulation pump motive natural gas from the “dehydrator vent stack emissions” definition.

The Fugitive Emissions Detection definition states that it includes emissions from equipment, components, and other point sources. “Fugitive emissions” is a term that naturally excludes point sources; therefore, “other point sources” should not be included in the definition of “fugitive emissions.” For example, if reciprocating compressor rod packing or centrifugal compressor wet seal degassing emissions vent through a piped vent, they are not a fugitive emission source;

however, if they do not pass through a piped vent, they are a fugitive emission source. We request that EPA remove “other point sources” from the “fugitive emissions detection” definition.

The Sales Oil definition states that it can be measured at a lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge. A tank gauge, not a meter, measures sales oil at the tank. We request that EPA remove the term “meter” from the term “custody transfer meter tank gauge” in the “sales oil” definition.

Response: EPA agrees that some types of dehydrator circulation pumps do not vent the motive gas through the reboiler vent stack, and so today’s final rule removes the term “stack” from the dehydrator vent emissions definition. Today’s final rule requires reporting of glycol dehydrator vent emissions, which will include the reboiler vent stack and in that vent, glycol circulation pump pneumatic gas when an energy-assist pump which commingles rich TEG containing gas under contactor pressure with additional wet gas for mechanical advantage of the pump driver (piston). For dehydrators that use other types of gas pneumatic circulation pumps that vent the pneumatic gas directly to the atmosphere, those emissions will be reported as part of the glycol dehydrator emissions. Today’s final rule requires the use of a software program, such as the Glycalc™ program, for all dehydrators of 0.4 million cubic feet per day and above, which includes emissions from a gas pneumatic pump. EPA disagrees that these types of glycol circulation pumps would be covered under the natural gas driven pneumatic pump source category. Pneumatic driven pumps refer to chemical injection pumps and other such production well-site pumps that inject chemicals such as methanol into wells, flowlines, etc.

With regard to the definition of fugitive emissions detection today’s final rule replaces the term “fugitive” with “equipment leaks” and defines this the same way as the proposed rule defined fugitives, including “other point sources.” This is because the rule requires use of the IR camera for identifying such point sources as vents on transmissions compressor station condensate tanks, indicating the possibility of through-leaking scrubber dump valves.

In today’s final rule EPA has clarified the definition to state that sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer meter or custody transfer tank gauge.

Comment Number: EPA-HQ-OAR-2009-0923-1206-59
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
This section requires operators to report emissions separately for “standby” equipment. However, the term “standby” is not defined anywhere in the rule (neither Subpart W nor Subpart A). Moreover, equipment is generally not specifically designated by operators as “primary” or “standby.” This adds an additional layer of reporting that is unwarranted and confusing, uses nebulous terminology, and provides no meaningful information. We request that EPA remove this requirement.

Response: EPA has determined that most reporters understand the term standby with regard to compressors. Today's final rule uses the term "standby" in context with the mode of operation in which a compressor is not operating, but could be started-up at any moment. The functional terms used in today's final rule, generically referred to as "standby" are: "not operating, pressurized" and "not operating, depressurized." Examples include compressors at a natural gas transmission compressor station which are started up for peak demand periods, or feed and residue gas compressors in processing facilities that allow rotation of compressors for maintenance without losing facility throughput.

With regard to the requirement that reporters must measure emissions from compressors in all modes of operation, today's final rule clarifies that compressors are only to be measured in the operating mode in which they are found so long as each compressor is measured in the not-operating, depressurized mode at least once every three years. For more information, please see the response to Section II.F of the preamble to today's final rule and response to comment EPA-HQ-OAR-2009-0923-0055-16.

Comment Number: EPA-HQ-OAR-2009-0923-1206-61
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
Consistent with the comment on § 98.233(a), we request that EPA replace the word "count" with "estimate."

§ 98.236(c)(2):

Consistent with the comment on § 98.236(c)(18)(i), we request that EPA replace the word "count" with "estimate."

§ 98.236(c)(3):

Consistent with the comment on § 98.233(c), we request that EPA replace the word "count" with "estimate."

Response: EPA disagrees that it should replace the data reporting requirement to report the count of pneumatic devices and pneumatic pump counts with estimates. In order to estimate greenhouse gas emissions from these sources, reporters must use the counts of each piece of equipment in the equations listed under the methodologies, EPA requires this information as necessary activity data to inform future policy.

Comment Number: EPA-HQ-OAR-2009-0923-1297-5
Organization: Southern Ute Growth Fund
Commenter: Lynn Woomer

Comment Excerpt Text:
Also, the SUGF recognizes the usage of the term "large compressors," in Table W-4 of the preamble, and other locations within the proposed rule. As with other CAA programs, large compressors should be defined by EPA, to include compressors of a certain horsepower (hp) level. Thus, the SUGF recommends that EPA further define "large compressors" to be classified as compressors with a level of 2,000 hp or more.

Response: EPA no longer uses the term “large compressor” to classify compressors under subpart W, please see EPA-HQ-OAR-2009-0923-1019-2.

Comment Number: EPA-HQ-OAR-2009-0923-1298-11
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The Condensate definition states that it includes both water and hydrocarbon liquids. Although a condensate storage tank in a production field typically includes both water and condensate, the two separate into different phases and are removed from the tank as separate streams. The tank operator documents the condensate production volume as the condensate phase that is removed from the tank. It is not accurate to state that condensate includes water, and IPAMS requests that EPA remove “water” from the “condensate” definition.

Response: EPA disagrees that it should remove water from the definition of condensate for the purposes of Subpart W. Please see the response to EPA-HQ-OAR-2009-0923-1040-12.

Comment Number: EPA-HQ-OAR-2009-0923-1298-12
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The Conventional wells definition states that they do not employ hydraulic fracturing. “Conventional” gas reservoirs are typically underground formations composed of sandstone, limestone, dolomite, and/or mixed mineralogy, and “conventional” wells are those that produce from these types of reservoirs. The term “conventional” does not necessarily consider whether the formation has been hydraulically fractured. Many of the “conventional” and “unconventional” wells in the United States have been hydraulically fractured. IPAMS requests that EPA define the terms “conventional wells” and “unconventional wells” based on the well’s reservoir type, as opposed to whether the well operates in a fractured reservoir.

Response: EPA does not agree to define conventional and unconventional by reservoir type. Please see the response to EPA-HQ-OAR-2009-0923-1040-13.

Comment Number: EPA-HQ-OAR-2009-0923-1298-13
Organization: Independent Petroleum Association of Mountain States

Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The Dehydrator vent stack emissions definition states that it includes the motive natural gas used by the circulation pump. The natural gas employed and expelled by a circulation pump does not vent through the dehydrator vent stack; therefore, it is not accurate to group this stream with the emissions from the dehydrator still vent. In addition, natural gas driven pneumatic pump venting is a distinct source type that Subpart W addresses separately from dehydrator vent stacks. IPAMS requests that EPA remove circulation pump motive natural gas from the “dehydrator vent stack emissions” definition.

Response: EPA disagrees that it should remove gas-assisted glycol circulation pumps from the dehydrator vent stack emissions source, please see the response to EPA-HQ-OAR-2009-0923-1206-29.

Comment Number: EPA-HQ-OAR-2009-0923-1298-14
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
Fugitive emissions: EPA should define fugitive emissions in proposed Subpart W consistent with existing rules promulgated under the CAA to avoid confusion among various regulatory programs. EPA should apply the definition of fugitive emissions already found in 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state that “fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening.” For example, leaks from natural gas driven pneumatic controller and valves, pump seals, non-pneumatic pumps and connectors should all be considered fugitive emissions. The use of an additional term, such as “equipment leak,” will only introduce additional confusion and increase the reporting burden without providing additional useful information to EPA. IPAMS also requests that EPA remove “other point sources” from the “fugitive emissions detection” definition.

Response: EPA agrees to modify the proposed definition for fugitive emissions, and has deleted the word “unintentional” in today’s final rule. EPA has replaced the term “fugitive emissions” with “equipment leaks.” This change was made to ensure consistency with the terminology in the Alternative Work Practice to Detect Leaks from Equipment for 40 CFR parts 60, 63, and 65. While the commenter suggested that the addition of a term like equipment leaks would cause confusion, EPA disagrees that it will cause confusion in place of (rather than in addition to) the term fugitive emissions.

With regard to the suggested alteration to the term fugitive emissions detection, please see the response to EPA-HQ-OAR-2009-0923-1206-29.

Comment Number: EPA-HQ-OAR-2009-0923-1298-15
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
The Gas to oil ratio (GOR) definition states that it is the ratio of the volume of gas at standard temperature and pressure produced from a volume of oil when depressurized to standard temperature and pressure. The oil and gas industry does not typically measure GOR in this manner. GOR is usually expressed as the measured natural gas volume that separates at actual separator temperature and pressure (corrected to standard temperature and pressure) divided by the measured oil volume from the storage tank(s). IPAMS requests that EPA modify the GOR definition to accurately reflect the current industry-accepted method.

Response: EPA disagrees with this comment. Please see the response to EPA-HQ-OAR-2009-0923-1040-14.

Comment Number: EPA-HQ-OAR-2009-0923-1298-16
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
The Reservoir definition states that it is characterized by a single natural gas pressure system. This statement is not accurate because a reservoir can have multiple pressure systems that are separate pods with permeability barriers between them. IPAMS requests that EPA remove the last sentence from this definition.

Response: EPA agrees with the comment. For more information, see response to comment EPA-HQ-OAR-2009-0923-1040-15.

Comment Number: EPA-HQ-OAR-2009-0923-1298-17
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
The Sales oil definition states that it can be measured at a lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge. A tank gauge, not a meter, measures sales oil at the tank. IPAMS requests that EPA remove the term “meter” from the term “custody transfer meter tank gauge” in the “sales oil” definition.

Response: EPA agrees, and has revised today’s final rule to remove the term “meter” from the phrase “custody transfer meter tank gauge” in the definition of sales oil.

Comment Number: EPA-HQ-OAR-2009-0923-1298-18
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The Sour natural gas definition states that it is natural gas that contains significant concentrations of H2S and/or CO2 that exceed the concentrations specified for commercially saleable natural gas. The concentration of CO2 does not determine whether natural gas is considered "sour." The oil and gas industry considers natural gas to be "sour" based only on the H2S concentration. Although CO2 content is indirectly controlled by heat content specifications, most natural gas contracts do not contain a specification for CO2 content unless the natural gas contains an excessive concentration of CO2. In addition, the concentration of H2S at which a natural gas stream is considered "sour" is not a standard value across the industry. This concentration varies according to the production area and the sales contract. IPAMS requests that the "sour natural gas" definition not reference CO2 content, and suggests that EPA define the concentration at which natural gas is consistently considered "sour" to be 100 ppmv or more.

Response: EPA disagrees that it should remove CO_2 from the definition of the term sour gas. This term is used only in the definitions to describe the purpose of an acid gas removal unit, which applies equally to produced natural gas containing quantities of H_2S and/or CO_2 which must be reduced to meet sales gas quality. The methods for estimating emissions from acid gas removal units do not depend on the definition of sour natural gas; only on the concentration of CO_2 in the feed, product or vent streams.

With regard to defining one consistent level at which natural gas is considered to be "sour", EPA disagrees that this is necessary. EPA is not setting standards on the gas for the purposes of this rule. EPA is only concerned with the "sour" natural gas that is treated in an acid gas removal unit because the operator must either remove CO_2, H_2S, or both in order to get the gas to pipeline specifications. EPA is concerned because this is a significant source of greenhouse gas emissions. The threshold at which natural gas is considered to be sour does not affect compliance with this subpart.

Comment Number: EPA-HQ-OAR-2009-0923-1298-19
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
The Sweet Gas definition states that it is natural gas with low concentrations of H2S and/or CO2. As discussed in the comment for Sour natural gas, the concentration of CO2 does not determine whether natural gas is considered "sour" or "sweet." IPAMS requests that the "sweet gas" definition not reference CO2 content.

Response: EPA disagrees with this comment. For further details, please see the response to EPA-HQ-OAR-2009-0923-1298-18.

Comment Number: EPA-HQ-OAR-2009-0923-1298-20
Organization: Independent Petroleum Association of Mountain States

Commenter: Kathleen M. Sgamma

Comment Excerpt Text:

The Unconventional wells definition states that they are wells that employ hydraulic fracturing. The term "unconventional" applies to wells that produce from reservoirs that are not "conventional," most often coal beds and shales. In addition, the term "unconventional" typically refers to wells that produce from tight formations with a permeability less than 0.1 milli-Darcies. The term "unconventional" does not necessarily consider whether a reservoir has been hydraulically fractured. Many of the "conventional" and "unconventional" wells in the United States have been fractured. IPAMS requests that EPA define the terms "conventional wells" and "unconventional wells" based on the well's reservoir type, as opposed to whether the well operates in a fractured reservoir.

Response: EPA agrees, and has revised today's final rule for the definitions of completions and workovers and the associated reporting requirements. Please see the response to EPA-HQ-OAR-2009-0923-1040-13.

Comment Number: EPA-HQ-OAR-2009-0923-1298-21
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:

The Well completions definition states that it is a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This definition is not accurate. The term "well completion" typically refers to the process of connecting the well bore to the reservoir. It may include treating the formation or installing tubing, packer(s), or lifting equipment. IPAMS requests that EPA modify the "well completions" definition to reflect the description given here.

Response: EPA agrees, and has revised today's final rule for the definition of well completion such that it reflects the activities discussed in this comment. In today's final rule, the definition adds additional clarification that completions are the process of connecting the well bore to the reservoir and may include treating the formation or installing tubing, packer(s), or lifting equipment.

Comment Number: EPA-HQ-OAR-2009-0923-1298-22
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:

The Well workover definition states "This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop open new fractures in existing low permeability gas reservoirs." IPAMS requests that EPA modify this sentence to read, "This process may also include high-rate flowback of injected gas, water, oil, and sand used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs."

Response: EPA revised the final rule for the definition of well workover in such a way that partially matches the commenter's proposal. For more information see response to comment EPA-HQ-OAR-2009-0923-1040-18.

Comment Number: EPA-HQ-OAR-2009-0923-1305-12
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
98.6 Definitions

BP suggests the following changes to the definitions (proposed language changes/additions are shown in green):

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

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

Compressor means any machine for raising the pressure of a natural gas or *CO_2* by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

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

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

This definition combines two entirely different types of gas drying. Separate definitions should be provided for the two types of desiccant material used for dehydration in the oil and gas sector.

One is the mole-sieve type desiccant system that uses alumina, silica, etc. where the wet gas is passed through and the water is adsorbed onto the surface of the desiccant materials. Once loaded, the beds are regenerated by passing hot gas through them to drive the water out.

Generally, a plant/facility will have at least two sets of mole sieve type vessels so one can be in service and one in regeneration or cooling in preparation for switching beds. Unless the facility is using hot nitrogen for regeneration the medium is generally hot gas and is recycled back to the inlet of the plant. This type lasts for many years before the vessel needs to be opened and beads have to be replaced.

The second is a deliquescent (sacrificial) desiccant type that uses pelletized salts like calcium chloride or lithium chloride. They work by the hygroscopic salt attracting the water and being dissolved to saturated brine. These are the type that must be opened for replacement/replenishment of the desiccant.

The two new definitions that should be provided for deliquescent and mole sieve desiccant are as follows:

Desiccant - deliquescent means a hydro-phillic salt material used in solid-bed dehydrators to remove water from raw natural gas by adsorption and dissolving the salt into a brine. Deliquescent desiccants include, but are not limited to, pelletized calcium chloride or lithium chloride. Wet natural gas is passed through a bed of the granular or pelletized material where water is adsorbed onto the desiccant material and dissolves it into a brine, leaving the dry gas to exit the contactor. When the majority of the salt material is dissolved, the dehydrator vessel must be opened and the salt replenished.

Desiccant - mole sieve means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include, but are not limited to, activated alumina and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor. When the adsorption media is water loaded it is regenerated by passing hot gas through the media to dry it and prepare it for subsequent use. The regeneration gas is typically captured and recycled into the process for hydrocarbon gas or vented if nitrogen is used for regeneration. Mole sieve desiccants have a long life and typically are not replaced on a frequent schedule.

- Flare combustion means unburned hydrocarbons, including CH_4, *emissions resulting from incomplete combustion of gas in flares along with CO_2, and N_2O formed in the combustion process* ~~emissions resulting from the incomplete combustion of gas in flares.~~

The definition of flare combustion does not appear to be correct. It seems the term should be “flare combustion emissions” not just “flare combustion.” Also unburned hydrocarbons are only part of the resulting emissions, as NO_x, CO, and SO_x emissions are also emitted.

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

This differs from existing federal rules such as 40 CFR 52.21(i)(20) and 40 CFR 63.2, which state “Fugitive emissions means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.” The fugitive emissions definition should not result in an expansion of the current CAA regulatory definition of fugitive emissions by including the phrase "unintentional" emissions.

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

The definition should be modified to include: *“Compressors on an individual well site or at a centralized tank battery or flow station, with single or multiple wells, and serving only the wells on or connected to the same site are excluded from this definition.”*

- New Definition for Gas Well: EPA uses the term “gas well” throughout Subpart W but does not offer a definition for this term and thus creates confusion. For example It is unclear whether the calculations required for ‘gas wells’ in 98.233(f), (g), and (h) would apply to wells that do not produce natural gas in commercially saleable quantities. BP recommends a definition consistent with the intent of the rule.

New Definition: *Gas well: A well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.*

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

This definition implies the "high-bleed" pneumatic device and the controller are different things, when in actuality the "high-bleed" pneumatic device/controller and the valve actuator are different devices. In addition, the correct term for these devices is pneumatic controllers. The definition should also be clarified that it is intended to include only continuous bleed devices, as described in 98.233(a). The following revisions are suggested:

High-Bleed Pneumatic ~~Devices~~ *Controllers* are automated *"continuous bleed"* flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator *or other process* controller. High-bleed controllers ~~where it~~ vent~~s~~ (bleed~~s~~) to the atmosphere at a rate in excess of six standard cubic feet per hour.

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

The following revisions are suggested:

Low-Bleed Pneumatic ~~Devices~~ *Controllers* mean *pilot operated* automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. ~~Part of~~ *On actuation*, the gas power stream which is regulated by the process condition, flows to a valve actuator *or other process* controller. *On de-actuation, the gas power stream used to actuate the process controller* ~~where it~~ vents (bleeds) to the atmosphere. *Although the amount of gas vented at pilot operated controllers depends on the amount of power gas used for actuation the typical rate* is ~~at a rate~~ equal to or less than six standard cubic feet per hour.

- New Definition: BP recommends a definition of natural gas distribution be added to the rule as follows:

Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations, that physically deliver natural gas to end users. This category excludes infrastructure and pipelines delivering natural gas directly to major industrial users upstream of the local distribution company inlet and "farm taps" upstream of the local distribution company inlet.

- New Definition for Oil Well: BP recommends a definition of oil well be added to the rule as follows:

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

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

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

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

- Turbine meter means a flow meter in which a gas or liquid flow rate through the ~~calibrated tube~~

meter spins a turbine from which the spin rate is detected and ~~calibrated to measure~~ converted to the fluid flow rate. *Turbine meters are typically factory calibrated and can only be field calibrated by use of a "proving meter" approach.*

B. Section 98.7(m)(l)

Add the following AAPG publication to the reference in 98.7(m)(1): Alaska Geologic Province Boundary Map; AAPG - CSD - USGS; 1978

C. Section 98.230(a)(1) Offshore petroleum and natural gas production

The rule text includes inland waters which is not correct. In addition, 98.230(a)(1) and Section 98.238 both provide the definition of offshore petroleum and natural gas production. The definitions differ in that Section 98.238 states "[a]ll production equipment that is connected via causeways or walkways are one facility." This text should be added to Section 98.230(a)(1). BP recommends Section 98.230(a)(1) be revised to:

Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from *beneath* the ocean *or lake* floor and that transfers such hydrocarbons to hydrocarbon to storage, transport vessels, or onshore. *In addition, offshore production includes secondary platform structures and storage tanks connected to the platform structure via causeways or walkways.*

D. Section 98.230(a)(4) Onshore natural gas transmission compression

The definition is not clear regarding residue gas compression located at gas plants. Modify the rule text as follows:

Onshore natural gas transmission compression. Onshore natural gas transmission compression means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, a transmission compressor station may includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. *Residue (sales) gas compression located at Natural Gas Processing Facilities are included in the processing category and excluded from this category.*

E. Section 98.230(a)(8) Natural Gas Distribution

The description does not exclude direct delivery to major industrial users and/or "farm taps" from classification as distribution. Modify the description as follows: Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations, that physically deliver natural gas to end users. *This category excludes infrastructure and pipelines delivering natural gas directly to major industrial users upstream of the local distribution company inlet and "farm taps" upstream of the local distribution company inlet.*

Response: EPA agrees, and has revised today's final rule for the definition of acid gas; please see the response to EPA-HQ-OAR-2009-0923-1151-17.

EPA agrees with the suggested clarification to the terms air-injected flare and compressor. Today's final rule reflects these clarifications.

EPA disagrees with the proposed changes to the definition of condensate; please see the response to EPA-HQ-OAR-2009-0923-1018-19.

With regard to the term desiccant dehydrator, EPA intended that only desiccant dehydrators using a hydro-phillic salt material are included under subpart W, and thus, mole sieve dehydration is not included.

EPA disagrees the proposed definition for flare combustion; however, however EPA has revised today's final rule for this definition. Please see the response to EPA-HQ-OAR-2009-0923-0847-4.

EPA agrees that it should alter the definition of fugitive emissions to not include the term "unintentional" to conform to the definition in other rules. Please see the response to EPA-HQ-OAR-2009-0923-1151-17.

EPA agrees, and has revised today's final rule to strike the term "meter" from the phrase "custody transfer meter tank gauge" in the definition of sales oil.

In today's final rule, EPA has decided not to include gathering and boosting equipment at this time. For more information, please see Section II.F of the preamble to today's final rule.

EPA agrees, and has revised the rule to include definitions for gas well and oil well in 98.238. With regard to the proposed definition changes to high-bleed and low-bleed pneumatic devices, EPA has altered the way in which pneumatic devices are defined. Please see the response to EPA-HQ-OAR-2009-0923-1024-38.

EPA does not consider the suggested changes to the definition of re-condenser or turbine meter to be substantially different or clarified over what is already in subpart W; and thus, disagrees with that the changes are necessary.

EPA agrees with the addition of the AAPG publication to Section 98.7 and has made the necessary changes to today's final rule.

EPA disagrees with the comments on "onshore petroleum and natural gas production owner or operator." However, EPA has revised this definition in today's final rule in Section 98.238. EPA disagrees with the commenter on the exclusion of inland waters from offshore and has retained it in the source category definition in Section 98.230 in today's final rule. EPA agrees with the commenter regarding "walkways," and has revised today's final rule offshore source category definition in Section 98.230. EPA has also revised the definition of offshore in Section 98.238, and clarifies that lakes are included.

EPA agrees with the comment about onshore natural gas transmission compression. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-20.

EPA agrees and has revised today's final rule in Section 98.230, to clarify that farm taps are not included in the definition of natural gas distribution in today's final rule For further details, please see the response to EPA-HQ-OAR-2009-0923-1016-24.

Comment Number: EPA-HQ-OAR-2009-0923-0049-2
Organization: American Gas Association
Commenter: Pamela Lacey

<u>Comment Excerpt Text:</u>
EPA Seriously Underestimates the Burdens on Gas Utilities

It is difficult to assess the economic burden of collecting and reporting this information, given that EPA has not provided a clear definition of several key terms, including "optical gas scanning" equipment and "M&R stations."

Response: EPA disagrees that it has not provided a clear definition of optical gas imaging equipment. Today's final rule prescribes that reporters may use an optical gas imaging instrument in accordance with 40 CFR part 60, subpart A, section 60.18(i)(1) and (2). These are the same instruments used for the Alternative Work Practice for Method 21.
EPA agrees, and has revised today's final rule to clarify which M&R stations are required for leak detection. For further details, please see the comment response in Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-0837-2
Organization: Canadian Gas Association
Commenter: Michael Cleland

<u>Comment Excerpt Text:</u>
Based on Canadian LDC reporting experience, the proposed facility definition for LDCs appears to be workable, although we have had considerable discussion relating to how to split "transmission" from "distribution" for companies that operate and are regulated as a single entity.

Response: EPA has reviewed these comments and today's final rule provides guidance on "co-located" facilities. Normally, transmission systems are regulated by a different entity than distribution facilities, and the separation of those facilities is clear from the regulations. However, it may be possible for a local distribution company public utility agreement to cover equipment normally found in transmission compressor stations. This would be considered a "co-located" facility. For example, if a local distribution company is operating within its facility boundaries and under a single regulatory agreement that covers the distribution operations as well as one or more transmission compressor stations, today's final rule requires the reporter to determine the industry segment for which the majority of emissions occur and report all equipment within that facility for which there is a method defined. A reporter must still report all emissions sources from each co-located source. For example, if distribution and transmission facilities are co-located, all emissions sources for both distribution and transmission must be reported. If the data collection or measurement methodologies are not consistent between source categories, the reporter uses the methodologies as defined under the source category from which the emissions are greatest. For more information, see response to comment EPA-HQ-OAR-2009-0923-1024-14.

Comment Number: EPA-HQ-OAR-2009-0923-0955-5
Organization: American Public Gas Association (APGA)
Commenter: Bert Kalisch

<u>Comment Excerpt Text:</u>
The Final Rule should clarify that customer meter sets are part of the service line and, hence, are not to be reported in any other category.

The terms .meter. .regulator, .meters, and .regulator stations. (or .M and R stations.) are not defined, and frequently used interchangeably, in the Proposed Rule. M and R Station is a terms of art used in the gas distribution industry to refer to gate stations where utilities receive gas from their pipeline-suppliers. Regulator stations include district regulators that cut the pressure of gas at various points throughout the distribution piping network. The preamble makes it clear that EPA's intent is to follow the industry usage:

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

Individual customer meter sets are, by industry norm and Federal pipeline safety regulations, considered part of a customer service line and, are obviously not part of a gate station or a district regulator. However, customer meter sets usually contain both a regulator and a meter. Because the terms .meter, M and R Station, and .regulator, are not defined in the Proposed Rule, these terms could be unreasonably interpreted to include over 60 million customer meter sets.

Such an interpretation would impose an enormous undue burden on LDCs. Almost all customer meter sets are above ground and, by operation of Section 98.232(i)(1) and 98.233(q) of the Proposed Rule, would require an annual leakage survey to determine the count of such meters that are leaking. Accordingly, the treatment of customer meter sets as above ground meters, regulators or M and R stations would impose enormous costs and undue burdens.

Such massive additional costs and burdens would be entirely unjustified. As noted, industry norm is to treat customer meter sets as part of a service line. Notably, PHMSA regulations confirm this practice at they include customer meter sets within the definition of a service line. Thus, any fugitive emissions from customer meter sets are already included in the Population Emission Factor for service lines in Table W-7. Accordingly, to include customer meter sets again as separate meters, regulators, or M&R stations, would be to provide a double count of emissions—at an enormous unjustified expense. For these reasons, APGA urges EPA to clarify that the terms, .meter, .regulator, and .M and R station, as used in the Proposed Rule do not include customer meter sets.

Response: EPA agrees, and has revised today's final rule to clarify which M&R stations are required for leak detection. For further details, please see the comment response in Section II.F of the preamble to today's final rule.

EPA disagrees that residential meters are accounted for in the service line population emission factors provided in subpart W. These emission factors were developed in the EPA/GRI 1996 report which provides separate emission factors for the residential meters – they represent only the service pipeline leaks. Subpart W does not require the reporting of residential meters, only the service lines.

Comment Number: EPA-HQ-OAR-2009-0923-1009-4
Organization: Xcel Energy Inc.
Commenter: Eldon Lindt

<u>Comment Excerpt Text:</u>
M&R Definition

The proposed rule's failure to define M&R stations makes it very difficult to determine compliance requirements and ensure that the necessary resources to support compliance are scheduled and/or obtained. The rule does not clearly state if end-use residential, commercial and industrial customer meter sets are to be included in the annual survey. For Xcel Energy, the number of stations requiring leak surveys could increase from 2800, if just district regulating stations are included, to over 1.8 million if the definition of M&R stations includes all sales meters for industrial, commercial, and residential customers. The resources and time required for performing the leak surveys and reporting differ substantially depending upon the M&R definition employed. Since natural gas in distribution systems is required to be odorized and our customers readily call if they detect any odors, Xcel Energy recommends that the M&R definition only include district regulating stations.

Response: EPA agrees, and has revised today's final rule to clarify which M&R stations are required for leak detection, and customer meters are not included. For further details, please see the comment response in Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1016-22
Organization: American Gas Association

Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>

Clarify the Subpart A Definitions of "Connector" and "Open-ended valves or lines" As Applied to Natural Gas Facilities Under Subpart W

The 2010 Proposal would require LDCs to report fugitive emissions from and conduct annual leak surveys of eight listed components at city gates and M&R stations, including "connectors" and open ended lines.[260] Proposed section 98.233(q) requires an annual leak detection survey of these components. 75 Fed. Reg. at 18637, 18643.] In Subpart A of the MRR, EPA defined the terms connector and open ended lines as follows:

"Connector means the flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, ''T's'' or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part."

"Open-ended valve or lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping."[261]

Under these definitions, a standard LDC regulator and meter could be deemed to have up to 90 connectors and several open-ended lines. In addition, it could include virtually any regulator or meter. Almost all components (meters, regulators, valves) in a distribution system are connected into the system by bolted flanges on both sides of the component. One problem we have with the generic definition in Subpart A is that it does not give our members guidance regarding flanges. EPA could receive reports regarding two categories of leaks associated with each component (i.e. component flanges and the component itself). It is not clear to us whether this is what the agency is seeking.

The reference to "process fluid" in the term "open-ended valve or line" is confusing. In theory, under fluid mechanics, a fluid is defined as either a liquid or gas. There are some circumstances in which natural gas can behave as a liquid (for example when converted to LNG under extremely low temperatures). Nevertheless, in the context of natural gas distribution or underground storage facilities, natural gas is in a gaseous state and is not a liquid. In the normal sense of the word "liquid," natural gas distribution systems do not transport fluids other than occasional, very small quantities of hydrocarbon condensates or water. Accordingly, under a common sense interpretation of the Subpart A definition, LDCs do not have any open ended valves or lines. Given that EPA specifically listed this component for LDCs and other natural gas

[260] Proposed 40 C.F.R. §98.232(i)(1) requires LDC to report fugitive emissions from "connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines" at "above ground meter regulators and gate station[s].

[261] 40 C.F.R. 98.6.

segments, we suspect the agency really means "process fluid or gas" and the term is intended to apply to permanent purge vents. We request that EPA provide an amended definition of open-ended line for purposes of Subpart W that includes this clarifying change..

To limit the burden of leak surveys and reporting for city gates and district M&R stations and to facilitate compliance and implementation of the rule, AGA asks EPA to adopt a different definition of these terms for use in Subpart W that will better align with natural gas distribution operations. We request that EPA adopt the following definitions for use in Subpart W:

Connector means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, such as elbows, reducers, ''T's'' or pipe unions. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part. This definition does not include flanges required to install components such as valves, meters, regulators, and open-ended lines.

Open-ended valve or lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid or gas and one side open to atmosphere, either directly or through open piping.

Response: EPA disagrees that it must clarify for subpart W that the term "fluid" in the subpart A definition for "open-ended line" to expressly state that gas is also considered a fluid. It is clear in the context of natural gas distribution that the "process fluid" is natural gas and uncapped or unplugged vent and drain connections are the open-ended lines subject to leak surveys in the rule. Further, today's final rule defines a size of over 0.5 inches diameter subject to leak surveys, so it would be extremely unlikely that one LDC meter and regulator would have up to 90 connectors and several open-ended lines. Most tubing and tubing connectors will be under the size limits.

EPA disagrees that it should change the definition of connector to not include flanges required to install components such as valves, meters, regulators, and open-ended lines. Today's final rule requires custody transfer city gate stations to perform a leak survey, and the leaks found to be categorized for application of leaker factors provided in the rule to estimate emissions. Flanges that connect valves and meters to piping are connectors. Seal welded flanges found leaking are still leaking connectors. Valve bonnet flanges, stem packing, grease nipples and other components found leaking on a valve exclusive of the piping connector flanges are valve leaks. The tables of leak factors by component type are taken from recent equipment leak surveys where the contractor had to combine leaks in logical categories as is required in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1059-20
Organization: Montana-Dakota Utilities Co.
Commenter: Abbie Krebsbach

<u>Comment Excerpt Text:</u>
In the proposed Subpart W Rule, EPA requires fugitive emissions reported from "open ended

pipe". We believe that the EPA means "open ended pipe" to be "vent stacks for relief valves or blow down stacks" at meter and regulator stations. The MDU LDCs do not normally inventory "vent stacks or blow down stacks" and MDU recommends that the EPA either clarify what this term means or remove it from the Subpart W Rule. Also, the EPA requires fugitive emissions reported from "connectors" at meter and regulator stations. MDU does not know exactly what this term encompasses. Also, the MDU LDCs do not inventory all connectors, such as 90 degree elbows, T-fittings, small sections of pipe and small control valves.

Response: Today's final rule does not limit equipment leaks from open-ended lines to blowdown vent stacks (subpart W does not use the term "open ended pipe"). The definition for open-ended lines is provided in subpart A, "Open-ended valve or lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid or gas and one side open to atmosphere, either directly or through open piping." Hence, an uncapped or unplugged vent or drain connection is an open-ended line. An equipment blowdown valve connected to an open vent stack is an open-ended line during the time that the blowdown valve is closed. Special provisions are described in the rule for calculating or measuring equipment blowdown emissions when blowdown valves are opened, during which time they are not open-ended lines.

Today's final rule requires LDCs to perform leak surveys at above ground custody transfer city gate stations, and use leaker factors for all leaks found in component categories. For more information, see response to comment EPA-HQ-OAR-2009-0923-1016-22.

Comment Number: EPA-HQ-OAR-2009-0923-1016-23
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
Clarify the Definition of Distribution Facility To Exclude Transmission Lines and Small, Remote Distribution Systems Operated by LDCs

AGA recommends that EPA revise the definition of Natural Gas Distribution Facility to clearly exclude natural gas "transmission" pipelines, referring to the definitions of "distribution" and "transmission" provided in DOT PHMSA's regulations at 49 C.F.R. Part 192, §192.3. In the 2010 Proposal for Subpart W, EPA proposes to define a distribution facility as "distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system." While we believe your intent is to exclude intrastate and interstate transmission pipelines, the definition is inadvertently unclear, because some LDCs operate significant amounts of transmission lines. A clear definition of distribution line that excludes "gathering lines" and "transmission lines" as defined in at 49 C.F.R.§192.3 will remove that ambiguity.

Most LDCs are served by affiliate or interstate transmission pipelines, and the definition of a distribution facility as an LDC, which is regulated as a separate company by a Public Utilities

Commission (PUC) is designed to fit that business model. However, several AGA members operate both transmission and distribution systems. The definition of a distribution facility needs to be clarified to determine the specific operations that are included in it.

The definition of a distribution facility should be based on physical attributes such as Maximum Allowable Operating Pressure (MAOP) instead of corporate ownership or regulatory body in order to make the distinction between distribution facilities and other facilities clearer.

In addition, small, remote distribution sub-systems should be exempted from the reporting requirements, even if owned/operated by the same large company, because the amount of emissions identified from these sub-systems would not be commensurate with the time, cost, and effort required to report them. Our members estimate that small sub-systems serving fewer than 140,000 customers emit far less than the 25,000 metric tons of CO2e threshold. We therefore propose that “distribution facility” should be defined as “a contiguous network of distribution lines and services operating at less than 100 psig Maximum Allowable Operating Pressure (MAOP) and serving more than 140,000 customers.” In addition, the term “distribution line” should be defined to have the same meaning as in 49 C.F.R. §192.3.

Response: EPA agrees that it would be beneficial to reporters to clarify the definition of natural gas distribution to not include transmission pipelines. Today’s final rule defines natural gas distribution in 98.230 as the distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations that physically deliver natural gas to end users. This category does not include customer meters and the infrastructure and pipelines delivering natural gas directly to major industrial users and "farm taps" upstream of the local distribution company inlet.” EPA disagrees with revising the facility definition of natural gas distribution to include a threshold for operating pipeline pressure and number of customers. EPA determined that the estimated number of natural gas distribution facilities reporting under subpart W and the estimated burden are reasonable. Please see the response to comment EPA-HQ-OAR-2009-0923-0049-7 and the Economic Impact Analysis Section 5 in EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-1016-24
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
Clarify Distribution Facility Includes Only The Portion of Gate Stations Owned by LDCs, Excludes Customer Meters, and Excludes Farm Taps

In the proposed rule, gate stations are considered to be part of the distribution system, and LDCs are required to report emissions from them. However, in many cases, LDCs only own part of the gate stations, which are also considered to be part of the transmission system. AGA therefore urges EPA to:

- Clarify that only the distribution portion of the gate station is within the natural gas distribution system for purposes of the threshold determination and subject to reporting by the LDC;

- Clarify that metering and/or regulation to customers is not subject to the leak survey and reporting requirements;
- If the intention is to include larger customer meter and regulator stations, then a clearly defined threshold should be identified, such as meter design capacity (e.g., 15,000 Dth/day) or nominal regulator size (e.g., four inch); and
- Clarify that farm taps (i.e. gas pressure regulation installed on services connected to transmission pipelines) are not included in the count of metering and/or regulator stations.

Response: EPA agrees that it is useful to clarify for which distribution meter and regulator stations it prescribes leak detection and leaker factors. Today's final rule clarifies that customer meters are not covered by subpart W, and leak detection is required only at above ground metering and regulator city gate stations at which custody transfer occurs. The remainder of above ground metering and regulator stations will be monitored by a population count and a population emission factor developed from the average emissions per station that was monitored with leak detection. For more information, please see the comment response in Section II.F of the preamble to today's final rule.

EPA did not intend for reporters to monitor and report emissions from farm taps. In today's final rule in Section 98.230, the definition of natural gas distribution clarifies that farm taps are not included.

EPA disagrees that it must clarify that only the distribution portion of the gate station is required for monitoring by natural gas distribution facilities. Distribution facilities are only to monitor the prescribed sources under their ownership or operation. That is, distribution facilities do not report the transmission portion of the gate station that is not part of the distribution system.

Comment Number: EPA-HQ-OAR-2009-0923-1151-22
Organization: American Petroleum Institute
Commenter: Karin Ritter

<u>Comment Excerpt Text:</u>
Section 98.230(a)(8) Natural Gas Distribution. The description does not exclude direct delivery to major industrial users and/or "farm taps" from classification as distribution. Modify the description as follows: "Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations, that physically deliver natural gas to end users. This category excludes infrastructure and pipelines delivering natural gas directly to major industrial users upstream of the local distribution company inlet and "farm taps" upstream of the local distribution company inlet."

Response: EPA agrees, and has revised today's final rule to clarify that farm taps are not included in the definition in Section 98.230 of natural gas distribution under subpart W. Please see the response to EPA-HQ-OAR-2009-0923-1016-24.

Comment Number: EPA-HQ-OAR-2009-0923-1016-26
Organization: American Gas Association
Commenter: Pamela A. Lacey

<u>Comment Excerpt Text:</u>
Facility Definitions and Threshold Determination Issues

A. The Definition of "Facility" for Distribution is Overbroad

EPA is proposing to cast aside the normal, common-sense definition of "facility" in the case of natural gas distribution. The definition used for decades in other Clean Air Act programs is the same as the definition provided in Subpart A of the GHG Mandatory Reporting Rule (MRR). The term "facility" is defined in 40 C.F.R. §98.6 as follows:

''Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas.''

We support EPA's proposal to use this traditional definition of "facility" for natural gas pipeline compression, underground storage, LNG storage, and LNG import/export facilities that our members operate.

However, we are troubled by the novel, expansive definition EPA proposes for natural gas distribution. Instead of using the traditional definition of facility for natural gas distribution, EPA is now proposing to define a gas distribution "facility" to encompass virtually the entire distribution system operated by a single company, which in some cases can span an entire state.

Proposed section 98.238 defines the term as follows:

"Natural gas distribution facility means the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system."

75 Fed. Reg. at 18647.

As proposed, it is also not clear whether the definition would encompass the distribution pipes, city gates and M&R stations located in multiple states if they are operated by the same company. We do not believe this was the agency's intent. If the intent is to cut the boundary of the distribution "facility" at the state border, then at a minimum, the definition should be revised to say that the term natural gas facility means the listed pipe and equipment "located within a single state" that are operated by an LDC and regulated "by that state's public utility commission." However, the normal definition of the term "facility" should be used throughout the MRR – limited to sites with contiguous boundaries. This type of facility-level reporting by owners and operators would be consistent with other Clean Air Act and state-level regulatory programs, which will facilitate compliance and minimize the administrative burden of the proposed rule.

B. In the Alternative, EPA Should Clarify that the Unusual Definition of “Facility” for GHG Reporting Purposes Should Not Be Used for the PSD Tailoring Rule or Other Clean Air Act Purposes

AGA is particularly concerned that the expansive definition of distribution facility could be adopted in other contexts, such as future phases of the Prevention of Significant Deterioration (PSD) Tailoring Rule for greenhouse gas emissions. If EPA does not adopt the traditional definition of “facility” for natural gas distribution, then the agency should at least clarify that other Clean Air Act programs should continue to use the traditional definition of “facility” to determine whether emissions from a facility exceed regulatory thresholds requiring pre construction permits or the application of control technology. Otherwise, far too many operating decisions within a local distribution system could require time and resource consuming regulatory decisions.

Response: EPA disagrees that it must redefine the natural gas distribution facility definition in Section 98.238 of today’s final rule to adhere more closely to the definition of “facility” in subpart A of The Final Mandatory GHG Reporting Rule (“Final MRR”), (40 CFR part 98). For the purposes of today’s final rule, the provided definitions supersede those provided in subpart A. EPA deemed it necessary to define facilities this way in order to achieve the desired 80% coverage at the 25,000 tonne CO_2e threshold. For more information regarding EPA’s facility definition choice, please see chapter 4.c.i. and 5. of the background technical support document in the rule making docket (EPA-HQ-OAR-2009-0923).

In today’s final rule, the definition of facility, as it relates to natural gas distribution, has been clarified to be the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipality-owned distribution system. EPA disagrees that the definition should include state boundaries, if an LDC serves areas on both sides of a state boundary – so long as it is regulated as a single operating company – then it will be considered one facility by this rule. EPA understands the concern that two systems separated by several states under common ownership being considered a single facility; however, it has determined that the current definition appropriately addresses that concern.

EPA disagrees that it should stipulate in subpart W any conditions or exclusions on the data collected, which is expressly for the purpose of informing future policy without bias on what or how that policy may be determined. The data cuts both ways by not only indicating sources of emissions large enough to warrant abatement, but also sources of emissions too small to cost-effectively abate, or that current practices are adequately managing those emissions.

Comment Number: EPA-HQ-OAR-2009-0923-1016-28
Organization: American Gas Association
Commenter: Pamela A. Lacey

Comment Excerpt Text:

Revise Facility Definition for Underground Storage to Clearly Exclude Transmission Lines Between Wellheads

AGA appreciates that EPA apparently has not defined underground storage facilities quite as broadly as it has defined onshore natural gas production facilities – which would extend across multiple states in an entire "hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code" pursuant to proposed section 98.238. However, it appears the definition of underground storage facility could be nearly as broad, could cross state lines and would extend across many square miles. The source category for underground natural gas storage is defined to include widely scattered surface facilities connected to an underground storage salt cavern or depleted gas or oil reservoir.

This broad definition raises a concern similar to one that we raised with respect to distribution. Underground storage facilities include transmission lines. The DOT reclassified all gathering lines in natural gas storage facilities as transmission lines several years ago. Only lines connecting production wells to processing and compression stations may be called gathering lines. In the 2010 Proposal, EPA proposes to exclude transmission lines from Subpart W, however, it appears that the agency only contemplated this exclusion in the context of interstate natural gas pipeline systems and did not realize that DOT-defined transmission lines are also operated by LDCs and within underground storage facilities. AGA asks that EPA revise section 98.230(a)(5), defining the source category for underground natural gas storage, to explicitly exclude transmission lines.

Response: EPA disagrees that it must clarify the definition of underground natural gas storage to not include transmission lines, because transmission pipelines are not required for monitoring and reporting under subpart W as specified under Sections 98.232 - GHGs to report or 98.233 - Calculating GHG emissions of today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1065-3
Organization: The Clean Energy Group
Commenter: Michael Bradley
Comment Excerpt Text:

Clarify the definition of natural gas distribution facility to clearly delineate between transmission and distribution assets;
Clarify the definition of above grade meter regulators (M&R) stations to exclude customer meters to reduce reporting costs;

Response: EPA agrees, and has revised today's final rule to clarify the delineation between transmission and distribution assets in 98.230. Please see the response to EPA-HQ-OAR-2009-0923-1016-23.

EPA agrees that it is beneficial to reporters to clarify that above ground meter and regulator stations do not include customer meters. Today's final rule states that customer meters are not included for reporting under subpart W. Please see the comment response in Section II. F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1065-8
Organization: The Clean Energy Group
Commenter: Michael Bradley

Comment Excerpt Text:
Distribution Facility Definition
The proposed definition of "facility" for natural gas distribution differs from the definition of facility applied in the remainder of the MRR. For natural gas distribution facility, EPA is proposing the following definition:

Natural gas distribution facility means the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

The Clean Energy Group generally agrees with this definition for the purposes of this rule especially since this is the approach LDCs currently utilize for other reporting programs including the Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration, the Federal Energy Regulatory Commission (FERC), and EPA's Natural Gas Star Program.

However, many LDCs also own and operate transmission assets in addition to their distribution assets. As such, this facility definition should be further developed in order to delineate the boundary between the distribution and transmission assets. The Clean Energy Group also suggests that distribution facilities be redefined to exclude small, remote sub-systems in order to reduce reporting costs as noted below.

Response: EPA revised today's final rule to clarify the delineation between transmission and distribution assets in 98.230. Please see the response to EPA-HQ-OAR-2009-0923-1016-23. It is unclear to EPA what the commenter meant by "remote sub-systems."

Comment Number: EPA-HQ-OAR-2009-0923-1099-2
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Metering & Regulating (M&R) Stations
The definition of "Metering & Regulating (M&R) Stations" is used differently in different sections of the regulation and is not clearly defined. In the preamble (pg 18617) you use the term "gas metering and pressure regulation equipment (M&R)". In 98.232.i.l, you refer to "meter regulators" and in the other sections, including 98.236, for example, you refer to Metering and

Regulating (M&R) stations. Not only is the term used differently in the proposed rule but it is unclear whether M&R includes only city gate meters, many of which do not have meters (and only have regulators), or whether it also includes customer meters (all of our residential meters have both a regulator and a meter)? In the preamble (pg 18617) it states that customer meters are part of the distribution system and that an LDC must "report for all the distribution facilities that they own or operate". Given this description, our interpretation is M&R would include customer (commercial and residential) meters.

Response: Today's final rule clarifies the definition of M&R stations. Please see the comment response in Section II. F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1099-6
Organization: New Mexico Gas Company
Commenter: Curtis J. Winner

Comment Excerpt Text:
Definition of source category: Natural gas distribution
The definition of LDC in 98.230 includes metering and regulating stations that physically deliver NG to end users. There is another definition of LDC in section 98.238. The definitions are not the same. EPA should refer to one or the other or define them the same in order to be consistent. Does the natural gas distribution source category include customer meters?

Response: EPA disagrees that it provides separate definitions for LDC in the proposed rule. The definition in 98.230 is the source category definition for natural gas distribution while the definition in 98.238 is the facility definition for natural gas distribution.
Today's final rule clarifies that reporters are not required to monitor and report emissions data for customer meters. Please see the comment response in Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-20
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.230(a) (4) Onshore natural gas transmission compression. The definition is not clear regarding residue gas compression located at gas plants. Modify the rule text as follows: "Onshore natural gas transmission compression" means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, a transmission compressor station may includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression located at Natural Gas Processing Facilities are included in the processing category and excluded from this category."

Response: EPA agrees in part with the proposed edits to the onshore natural gas transmission compression definition stated in this comment. Today's final rule corrects the grammar error in the definition with the additional clarification that residue gas compressors owned and operated by a gas processing facility, and dedicated to moving sales gas from that gas processing facility to a transmission system, whether inside or outside the processing facility fence line, are a part of the gas processing facility.

Comment Number: EPA-HQ-OAR-2009-0923-1152-11
Organization: Consumer Energy Company
Commenter: Amy Kapuga

Comment Excerpt Text:
Revise Facility Definition for Underground Storage

Consumers appreciates that EPA apparently has not defined underground storage facilities quite as broadly as it has defined onshore natural gas production facilities – which would extend across multiple states in an entire "hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code" pursuant to proposed section 98.238. However, it appears the definition of underground storage facility could be nearly as broad, could cross state lines and would extend across many square miles. The source category for underground natural gas storage is defined to include widely scattered surface facilities connected to an underground storage salt cavern or depleted gas or oil reservoir. For the reasons stated above, AGA urges EPA to revise section 98.230(a)(5) to use a more traditional definition of "facility" for underground natural gas storage.

Response: EPA disagrees that it should revise the definition of underground storage in today's final rule. The definition for underground natural gas storage includes the processes and operations (including compression, dehydration and flow measurement), and all the wellheads connected to the compression units located at the facility that inject and reproduce natural gas. Please see the response to EPA-HQ-OAR-2009-0923-1016-28.

Comment Number: EPA-HQ-OAR-2009-0923-1152-8
Organization: Consumer Energy Company
Commenter: Amy Kapuga

Comment Excerpt Text:
Clarify the Definition of Distribution Facility To Exclude Transmission Lines and Small, Remote Distribution Systems Operated by LDCs

Consumers recommends that EPA revise the definition of Natural Gas Distribution Facility to clearly exclude natural gas "transmission" pipelines, referring to the definitions of "distribution" and "transmission" provided in DOT PHMSA's regulations at 49 C.F.R. Part 192, §192.3. In the 2010 Proposal for Subpart W, EPA proposes to define a distribution facility as "distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution

Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system."

While we believe your intent is to exclude intrastate and interstate transmission pipelines, the definition is inadvertently unclear, because some LDCs operate significant amounts of transmission lines. A clear definition of distribution line that excludes "gathering lines" and "transmission lines" as defined in at 49 CFR§192.3 will remove that ambiguity. In addition, the term "distribution line" should be defined to have the same meaning as in 49 C.F.R. §192.3.

Clarify Distribution Facility Includes Only Portion of Gate Stations Partly Owned by LDCs, Excludes Customer Meters and Excludes Farm Taps

In the proposed rule, gate stations are considered to be part of the distribution system, and LDCs are required to report emissions from them. However, in many cases, LDCs only own part of the gate stations, which are also considered to be part of the transmission system. Therefore, Consumers urges EPA to:

• Clarify that only the distribution portion of the gate station is within the natural gas distribution system for purposes of the threshold determination and subject to reporting by the LDC;

• Clarify that metering and/or regulation to customers is not subject to the leak survey and reporting requirements;

• If the intention is to include larger customer meter and regulator stations, then a clearly defined threshold should be identified, such a meter design capacity (e.g., 15,000 Dth/day) or nominal regulator size (e.g., four inch); and

• Clarify that farm taps (i.e. gas pressure regulation installed on services connected to transmission pipelines) are not included in the count of metering and/or regulator stations.
D. Clarify Component Count Requirement

Proposed section 98.236(c)(19) "Data Reporting Requirements" states: "For fugitive emission sources using emission factors for estimating emissions report the following: (i) Component count for each fugitive emission source." If reporting will be required by component count instead of by station or facility, AGA recommends that EPA:

• Clarify that only a count of leaking components by type are required to be reported, not a count of all components by type; and

• Establish a size threshold for components, such as 2 inch nominal diameter.

Response: EPA agrees that it should clarify the source category definition of natural gas distribution to not include transmission pipeline. In today's final rule, the definition of natural gas distribution in 98.230 explicitly states that natural gas distribution does not include interstate and intrastate transmission pipelines.

EPA disagrees that it must clarify that only the distribution side of gate stations are required for reporting under the natural gas distribution facilities. Please see the response to EPA-HQ-OAR-2009-0923.

EPA agrees, and has revised today's final rule to clarify that customer meters are not required for reporting. Please see the comment response in Section II.F of the preamble to today's final rule. Additionally, the same section of the preamble also clarifies which metering and regulator stations are required for leak detection and how to account for the remaining stations.

EPA agrees and today's final rule clarifies that farm taps are not included in the definition of the natural gas distribution segment. Please see the response to EPA-HQ-OAR-2009-0923-1016-23. EPA agrees that it is beneficial to clarify the data reporting requirements for equipment leaks found in each leak survey. Today's final rule states that total count of leaks found in each complete survey must be listed by the date of the survey and each type of leak source for which there are leaker factors in Tables W-2, W-3, W-4, W-5, W-6, and W-7 of the rule.

EPA agrees that it should establish a threshold for component sizes required for leak detection; however, it disagrees that the threshold should be 2 inches. Today's final rule stipulates that tubing systems equal or less than one half inch diameters needn't be reported under the requirements of subpart W for leak detection and leaker emission factors and population count and emission factors, to be consistent with the leak detection and repair program (LDAR).

Comment Number: EPA-HQ-OAR-2009-0923-1152-9
Organization: Consumer Energy Company
Commenter: Amy Kapuga

Comment Excerpt Text:
The Definition of "Facility" for Distribution is Overbroad

EPA is proposing to cast aside the normal, common-sense definition of "facility" in the case of natural gas distribution. The definition used for decades in other Clean Air Act programs is the same as the definition provided in Subpart A of the GHG Mandatory Reporting Rule (MRR). The term "facility" is defined in 40 C.F.R. §98.6 as follows:

''Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas.''

We support EPA's proposal to use this traditional definition of "facility" for natural gas pipeline compression, underground storage, LNG storage, and LNG import/export facilities that our members operate. However, instead of using the traditional definition of facility for natural gas distribution, EPA is now proposing to define a gas distribution "facility" to encompass virtually the entire distribution system operated by a single company, which can span an entire state.

Proposed section 98.238 defines the term as follows:

“Natural gas distribution facility means the distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.” We would prefer a consistent, normal definition of the term “facility” throughout the MRR – limited to sites with contiguous boundaries. This type of facility-level reporting by owners and operators will be consistent with other Clean Air Act and state-level regulatory programs, which will facilitate compliance and minimize the administrative burden of the proposed rule.

B. In the Alternative, EPA Should Clarify that the Unusual Definition of “Facility” for GHG Reporting Purposes Should Not Be Used for the PSD Tailoring Rule or Other Clean Air Act Purposes

While Consumers agrees that it will be useful to develop a good estimate of greenhouse gas emissions from natural gas distribution, we do not agree that this requires such an expansive definition of distribution “facility.” We are particularly concerned that this expansive definition could be adopted in other contexts, such as future phases of the Prevention of Significant Deterioration (PSD) Tailoring Rule for greenhouse gas emissions. If EPA does not adopt the traditional definition of “facility” for natural gas distribution, then the agency should at least clarify that other Clean Air Act programs should continue to use the traditional definition of “facility” to determine whether emissions from a facility exceed regulatory thresholds requiring pre construction permits or the application of control technology. Otherwise, far too many operating decisions within a state-wide local distribution system could require time and resource consuming regulatory decisions.

Response: EPA disagrees that it must redefine the natural gas distribution facility definition in 98.238 to adhere more closely to the definition of “facility” in subpart A. Please see the response to EPA-HQ-OAR-2009-0923-1016-26.
The current definition includes the infrastructure spanning more than one state if it is part of the same system. Please see the response to EPA-HQ-OAR-2009-0923-1016-26.

EPA disagrees that it should stipulate in subpart W that other section of the Clean Air Act should not use this definition of natural gas distribution facility. Please see the response to EPA-HQ-OAR-2009-0923-1016-26.

Comment Number: EPA-HQ-OAR-2009-0923-1156-15
Organization: Laclede Gas Company
Commenter: Steve Donatiello

<u>Comment Excerpt Text:</u>
Definition of a Natural Gas Distribution Facility:

Laclede does not believe that the entire distribution system is truly a “Facility” as intended by the

Clean Air Act. Laclede believes that EPA incorrectly attempts to encompass a gas distribution system into its concept of a facility for the purpose of aggregating CO2e emissions. The distribution system piping network should not be used as a surrogate regulatory mechanism to connect together any number of otherwise distinct gas company components, located at widely dispersed locations, i.e. service buildings, compressor stations, process heaters, etc. By doing so, EPA is grasping for the reporting of inconsequential, incremental emissions. This is a classic case of diminishing returns for the investment. The gas distribution system should not be viewed/defined by EPA in this manner because, if total fugitive emissions calculated using EPA's approved emission factors for the gas distribution system exceed 25,000 metric tons/yr CO2e, it should certainly not automatically trigger reporting of combustion emissions from the LDC's other sites, when facilities at such sites were not otherwise required to report under existing subpart C. This is an unreasonable stretch.

Response: EPA does not agree that the definition of an LDC facility in Section 98.238 of today's final rule must conform with other Clean Air Act facility definitions or the facility definition in Subpart A, Section V of the Final Rule, October 2009. For more information see response to EPA-HQ-OAR-2009-0923-1016-26 and EPA-HQ-OAR-2009-0923-1044-1. EPA agrees that small combustion emissions need not be reported, and has established an external combustion equipment threshold. For more information on the threshold, please see the rulemaking docket (EPA-HQ-OAR-2009-0923) under "Equipment Threshold for Small Combustion Units**."** Internal combustion engines which would have to be reported under Subpart C for LDCs that exceed the 25,000 tCO_2e reporting threshold must still be reported, but under Subpart W starting data collection year 2011.

Comment Number: EPA-HQ-OAR-2009-0923-1156-16
Organization: Laclede Gas Company
Commenter: Steve Donatiello

Comment Excerpt Text:
EPA apparently recognizes that its definition of a "Facility" on page 56387 of the October 30, 2009 final rule is incongruent with a natural gas distribution system.

The April 12, 2010, proposed rule includes, at 40 CFR 98.230 (8), Natural Gas Distribution, under Definition of the source category. At yet another location in the proposed rule, specifically at 40 CFR 98.238, Definitions, EPA goes on to provide an additional definition for "Natural gas distribution facility." This appears to be EPA's attempt to define the entire gas distribution system as a "Facility" for purposes of the rule.

All of these definitions are yet in addition to the amended definitions on Page 18633 of the proposed rule; 40 CFR 98.6, Definitions. Laclede questions why EPA finds it necessary to list definitions at so many different locations throughout the rule. It appears this could be handled in a more efficient and straightforward manner.

Response: Definitions under 40 CFR 98.6 are applicable to all the subparts under 40 CFR part 98. Definitions listed under 40 CFR 98.238 either override definitions under 40 CFR 98.6 or delineate items that are only applicable to Petroleum and Natural Gas Systems (40 CFR part 98, subpart W). In today's final rule, the natural gas distribution source category is described in 40 CFR 98.230. The definition of a "Facility" for purposes of natural gas distribution is provided under 40 CFR 98.238, which is only applicable to Petroleum and Natural Gas Systems (40 CFR part 98, subpart W). It is necessary to distinguish natural gas distribution because the 98.6 definition is not appropriate to that sector and emissions which need to be reported from that sector. See, EPA-HA-OAR-2009-0923-1016-26.

Comment Number: EPA-HQ-OAR-2009-0923-1168-8
Organization: Delmarva Power a PHI Company
Commenter: Wesley L. McNealy

<u>Comment Excerpt Text:</u>
Metering & Regulation (M&R) Stations

DPL finds it is necessary for the EPA to clarify Subpart W's definition of above-grade M&R stations and the extent to which M&R stations would be subject to leak-detection surveys. Therefore, DPL requests that Subpart W clarify and/or prescribe certain M&R stations intended for surveys based on M&R station function, purpose, size, and/or pressure. DPL also requests that customer meters be excluded from leak detection surveys due to the extraordinarily high number of such meters.

Response: In today's final rule, the definition of natural gas distribution has been clarified in 98.230 to state that customer meters are not included. For further information on this comment, please see the response to comments in Section II.F of the preamble.
EPA has determined that requiring leak detection at meters and regulators based on size and/or pressure is not necessary. In EPA's expert judgment, defining a size and pressure limit for meter and regulator stations is difficult and confusing to reporters. As result, EPA decided to limit leak detection to only above-grade meters and regulators at city gate stations with custody transfer. For further information on this issue, please see the response to comments in Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1197-11
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

<u>Comment Excerpt Text:</u>
Based on the fact that the proposed rule does not provide clear definition of several key terms, including "optical gas scanning", "M & R stations".

Response: EPA agrees, and has revised today's final rule to clarify which M&R stations are required for leak detection, please see the response to comments in Section II. F of the preamble. In the proposed rule, the language "optical gas scanning" is not used. However, if the commenter is referring to "optical gas imaging", the EPA does not deem it necessary to define optical gas imaging instrument because procedures to use such an instrument and the necessary specifications of the instrument are outlined under 40 CFR 98.234.

Comment Number: EPA-HQ-OAR-2009-0923-1197-13
Organization: NiSource, Inc.
Commenter: Kelly Carmichael

Comment Excerpt Text:
EPA must clearly define the term "M & R station" to only include industrial metering and regulating stations.

Response: EPA agrees, and has revised today's final rule to clarify which M&R stations are required for leak detection, please see the comment response in Section II. F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1299-2
Organization: Northeast Gas Association
Commenter: Thomas M. Kiley

Comment Excerpt Text:
Definition of "Facility"

The concept of "facility" as it applies to a local distribution company (LDC) is still undefined within the proposed regulation. As indicated by AGA in its testimony in April, the proposed rule would likely apply to many more gas utilities and require a much greater burden than estimated by EPA. It is not clear whether EPA intends to define the facility as each distribution system – or all the distribution systems owned by a single "Distribution Company." If the intent is the latter, to combine all the separate distribution systems of a single company as one "facility" that spans hundreds of communities across a state, then many more utility companies would likely exceed the 25,000 ton per year threshold for reporting. Once included, those utilities would then have to estimate and report emissions for many small meter and regulator stations and city gate stations scattered across the state - as well as combustion emissions from sources that otherwise would not exceed the facility reporting threshold. Many of the LDCs in the Northeast operate in various locations without direct or contiguous links to each other; it is uncertain how this definition applies

Response: EPA disagrees that the facility definition in 98.238 for natural gas distribution needs to be clarified. Please see response to comment EPA-HQ-OAR-2009-0923-1016-26. EPA does not agree that the definition of an LDC facility in 98.238 must conform with other Clean Air Act facility definitions or the facility definition in Subpart A, Section V of the Final Rule, October 2009. For more information see response to EPA-HQ-OAR-2009-0923-1016-26 and EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1298-25
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
The term "natural gas processing plant" has been previously and consistently defined in other EPA CAA programs:

- 40 CFR Part 60 Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, defines Natural gas processing plant (gas plant) as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. Subpart KKK also defines Natural gas liquids as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas. As defined here, "natural gas liquids" are those light-end hydrocarbons that are extracted from a natural gas stream that must be stored in a closed pressurized tank to be maintained as a liquid. Taken together, these definitions do not incorporate the removal of water, condensate, oil, H2S, CO2, or any other component other than natural gas liquids.
- 40 CFR Part 68, Chemical Accident Prevention Provisions, defines Natural gas processing plant (gas plant) as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both, classified as North American Industrial Classification System (NAICS) code 211112 [previously Standard Industrial Classification (SIC) code 1321].

In addition, the oil and gas industry commonly understands the term "natural gas processing plant" to mean the extraction of natural gas liquids from a natural gas stream to meet the heat content specification of sales contracts. A Joule-Thompson unit or a refrigeration unit typically completes this natural gas liquids extraction. It is not appropriate to introduce a different definition for "natural gas processing plant" in this program. The contrast between industry's understanding of the term and the Subpart W definition of the term will lead to confusion among owners and operators, and will be inconsistent with the way EPA applies it under other parts of the CAA. IPAMS requests that EPA define "natural gas processing plant" as "a processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both."

Response: EPA reviewed and considered other definitions used in the Clean Air Act and implementing regulations, and where suitable for the purposes of subpart W, such as transmission compressor stations, adopted those facility definitions. In the case of gas processing facilities, EPA determined that limiting the definition to facilities that are significant sources of criteria air pollutant emissions, such as gas fractionation facilities, and excluding those facilities that have minimal criteria pollutants but significant greenhouse gas emissions is contrary to the intent of the Mandatory Reporting Rule, and therefore, EPA disagrees with this commenter's request. Please see response to comment EPA-HQ-OAR-2009-0923-1044-1. However, EPA has revised today's final rule for the source category definition of natural gas processing to include 1) all processing facilities that fractionate and 2) those that do not fractionate with throughput of 25 MMscf per day or greater. Please see "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923. In addition, EPA has revised today's final rule and no longer includes gathering lines and boosting stations in natural gas processing. Please see the preamble Section II.F.

Comment Number: EPA-HQ-OAR-2009-0923-1031-4
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

<u>Comment Excerpt Text:</u>
75 Fed. Reg. at 18636 (emphasis added).

The oil and gas industry commonly understands the term "natural gas processing plant" to mean the extraction of natural gas liquids from a natural gas stream to meet the heat content specification of sales contracts. A Joule-Thompson unit or a refrigeration unit typically completes this natural gas liquids extraction. It is not appropriate to introduce a different definition for "natural gas processing plant" in this program. The contrast between industry's longstanding usage of the term and other EPA regulations with the proposed definition in Subpart W will lead to confusion among owners and operators, and will be inconsistent with other existing EPA regulations under the Clean Air Act.

Accordingly, Anadarko strongly recommends that the definition in Section 98.230(a)(3) be revised to exclude field gathering and boosting stations, including any associated acid gas treating facilities, from the Onshore Natural Gas Processing source category definition, and that a new source category definition be included for "Onshore Natural Gas Gathering Compression and Treating Facilities." Using the definition of Onshore Natural Gas Transmission as a template, Anadarko respectfully requests that the source category definition for "Onshore Natural Gas Gathering Compression and Treating Facilities" be changed to the following:

Onshore natural gas gathering compression and treating facilities means any physically adjacent combination of compressors that move natural gas from production fields or other compression facilities into natural gas processing facilities, other gathering compression facilities, transmission pipelines, storage facilities, or other end users. In addition, natural gas gathering compression and treating facilities may include equipment for liquids separation, natural gas dehydration, acid gas removal, and tanks for the storage of water and hydrocarbon liquids. These facilities do not include equipment designed to extract natural gas liquids.

Response: EPA does not agree with this request to limit the gas processing facility definition to that in the Clean Air Act. For more information, reference EPA-HQ-OAR-2009-0923-1298-25. However, EPA has revised today's final rule and no longer includes gas gathering lines and boosting stations. See Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1080-43
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

<u>Comment Excerpt Text:</u>

The oil and gas industry commonly understands the term “natural gas processing plant” to mean the extraction of natural gas liquids from a natural gas stream to meet the heat content specification of sales contracts. A Joule-Thompson unit or a refrigeration unit typically completes this natural gas liquids extraction. It is not appropriate to introduce a different definition for “natural gas processing plant” in this program. The contrast between industry’s longstanding usage of the term and other EPA regulations with the proposed definition in Subpart W will lead to confusion among owners and operators, and will be inconsistent with other existing EPA regulations under the Clean Air Act.

Response: EPA does not agree with this request. For more information, reference EPA-HQ-OAR-2009-0923-1298-25.

Comment Number: EPA-HQ-OAR-2009-0923-1031-3
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

Comment Excerpt Text:
Defining natural gas gathering system compression facilities as part of a gas processing plant is inappropriate. The definition of a gas processing plant is well established in the context of the CAA, and it does not incorporate stand-alone gathering system compression facilities. Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission sector, are discreet and easily identifiable facilities. These facilities have been treated as stand-alone sites in all previous applications of the CAA, including all permitting programs and for GHG reporting under 40 CFR Part 98 Subpart C. Continuing this historical treatment of these facilities is not only the most appropriate action, it also will eliminate the certain confusion that will result from a new definition solely for use in Subpart W of Part 98.

EPA has repeatedly recognized the treatment of gathering system compressor stations as stand-alone facilities in past regulations and other documents, including in its Background Technical Support Document for the Petroleum and Natural Gas Industry, which states: The term “natural gas processing plant” has been previously and consistently defined in other EPA programs. A natural gas processing plant (gas plant) is defined under Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. See 40 CFR Part 60, Subpart KKK. Subpart KKK also defines natural gas liquids as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas. Accordingly, “natural gas liquids” are those light-end hydrocarbons that are extracted from a natural gas stream that must be stored in a closed pressurized tank to be maintained as a liquid. Taken together, these definitions do not incorporate the removal of water, condensate, oil, H2S, CO2, or any other component other than natural gas liquids.

In direct conflict with the foregoing statements by EPA and existing regulatory definitions, the proposed Subpart W definition of Onshore Natural Gas Processing in Section 98.230(a)(3) of the proposed rule appears to combine GHG emissions from gathering compression facilities and the gathering pipelines with gas processing plant emissions:

In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant.

Response: Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble. EPA does not agree with limiting gas processing to fractionation consistent with 40 CFR Part 60, Subpart KKK. For more information, reference EPA-HQ-OAR-2009-0923-1298-25 and EPA-HQ-OAR-2009-0923-1044-1. In the final rule EPA has revised the definition of natural gas processing facilities in 98.230, to include those with fractionation, and those without fractionation with a gas throughput capacity of 25 mmscfd and above. Please see the preamble Section II.E and "Minimum Gas Processing Throughput" in EPA-HQ-OAR-2009-0923.

Comment Number: EPA-HQ-OAR-2009-0923-1071-1
Organization:
Commenter: Michael Leonard

<u>Comment Excerpt Text:</u>
The definition of a natural gas processing facility under Subpart W is inconsistent with the definition of a natural gas processing facility under Subpart C, as Subpart W includes booster stations and gathering lines, while Subpart C does not. In many situations, extensive field work has already been completed and significant expenses incurred to assess the need for a natural gas processing facility to report under Subpart C for the 2010 reporting year. The inclusion of booster stations will create additional burden as companies will need to revisit every facility to include booster stations. We propose that booster stations be viewed as separate facilities within themselves

Response: Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the Preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1080-41
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman
<u>Comment Excerpt Text:</u>
The definition of a gas processing plant is well established in the context of the CAA, and it does not incorporate stand-alone gathering system compression facilities. Gas compression facilities, whether in the gathering systems upstream of gas processing or in the natural gas transmission

sector, are discreet and easily identifiable facilities. These facilities have been treated as stand-alone sites in all previous applications of the CAA, including all permitting programs and for greenhouse gas ("GHG") reporting under 40 CFR Part 98 Subpart C. Continuing this historical treatment of these facilities is not only the most appropriate action, it also will eliminate the certain confusion that will result from a new definition solely for use in Subpart W of Part 98.

EPA has repeatedly recognized the treatment of gathering system compressor stations as stand-alone facilities in past regulations and other documents, including in its Background Technical Support Document for the Petroleum and Natural Gas Industry, which states:

Both gathering/boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place.

U.S. Environmental Protection Agency, Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document ("TSD").

Response: Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1080-42
Organization: Aka Energy Group, LLC
Commenter: Barbara Wickman

Comment Excerpt Text:
For some segments of the industry (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying scope of reporting and responsible reporting entities. 75 Fed. Reg. at 18613.

The term "natural gas processing plant" has been previously and consistently defined in other EPA programs. A natural gas processing plant (gas plant) is defined under Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. See 40 C.F.R. Part 60, Subpart KKK. Subpart KKK also defines natural gas liquids as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas. Accordingly, "natural gas liquids" are those light-end hydrocarbons that are extracted from a natural gas stream that must be stored in a closed pressurized tank to be maintained as a liquid. Taken together, these definitions do not incorporate the removal of water, condensate, oil, H2S, CO2, or any other component other than natural gas liquids.

Additionally, natural gas processing plant (gas plant) is defined under the Chemical Accident Prevention program as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both, classified as North American Industrial Classification System (NAICS) code 211112 [previously Standard Industrial Classification (SIC) code 1321]. See 40 C.F.R. Part 68.

In direct conflict with the foregoing statements by EPA and existing regulatory definitions, the proposed Subpart W definition of Onshore Natural Gas Processing in Section 98.230(a)(3) of the proposed rule appears to combine GHG emissions from gathering compression facilities and the gathering pipelines with gas processing plant emissions:

In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of natural gas processing plant. 75 Fed. Reg. at 18636 (emphasis added).

Response: EPA does not agree with this request to define gas processing facilities as fractionation plants. For more information, reference EPA-HQ-OAR-2009-0923-1298-25. Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1174-10
Organization: Devon Energy Corporation
Commenter: Richard Luedecke

<u>Comment Excerpt Text:</u>
Onshore Natural Gas Processing Plants Definition

The proposed "onshore natural gas processing plants" definition that combines GHG emissions from gathering compressor facilities and the gathering pipelines with gas processing plant emissions is in conflict with existing CAA regulations and inconsistent with industry's longstanding usage of the term.

Major compression facilities are already subject to Subpart C reporting since their combustion emissions exceed 25,000 metric tones per year. In addition, smaller compression facilities, such as gathering compression facilities, with green house gas emission in excess of 25,000 metric tones per year, from combined combustion (Subpart C) and methane (Subpart W) emissions would also be required to report. The bulk of emissions from compressor facilities is from CO2 yet the aggregated definition of "onshore natural gas processing plants" in this subpart W proposal will significantly increase reporting from very small compressor facilities that, individually, would have relatively insignificant green house gas emissions, especially methane.

In fact, the proposed Subpart W will require reporting of gas gathering and processing facilities to nearly 100% for Devon, which is unreasonably burdensome. We strongly recommend that EPA excludes field gathering and boosting stations from the "onshore natural gas processing plants" source category definition.

Response: Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-1202-3
Organization: Enterprise Products
Commenter: Rodney Sartor

Comment Excerpt Text:
The definition of a gas processing plant is well established in the context of the CAA. It does not incorporate stand-alone gathering system compression facilities. Gas compression facilities are discrete and easily identifiable facilities that have been treated as stand-alone sites in all previous applications of the CAA, including all permitting programs and for GHG reporting under 40 CFR Part 98 Subpart C.

Response: Today's final rule does not include gathering lines and boosting stations and hence the issue of gathering pipelines is not relevant. For further clarification, please see Section II.F of the preamble.

Comment Number: EPA-HQ-OAR-2009-0923-0582-13
Organization: Western Climate Initiative (WCI)
Commenter: Michael Gibbs

Comment Excerpt Text:
Reporting of field gas combustion emissions should not be accomplished by adopting an excessively broad definition of pipeline quality natural gas, because the resulting use of Subpart C Table C-1 default factors will often lead to excessive errors in estimating emissions.

Response: EPA agrees with the commenter and added methods for onshore production and natural gas distribution to estimate the composition of field gas in lieu of using default factors in Subpart C. In today's final rule, reporters must determine the composition of field gas using either a continuous gas analyzer or use the most recent gas composition based on available sample analysis of the field.

Comment Number: EPA-HQ-OAR-2009-0923-0837-4
Organization: Canadian Gas Association
Commenter: Michael Cleland

Comment Excerpt Text:

Meter regulators: The current draft does not appear to include definitions for "gate stations" or "meter regulators". While the term "gate stations" is relatively clear, what is intended for "meter regulators" is not, and so it is difficult to gauge the full scale and impact of the draft rule's reporting requirements. We suggest that EPA consider removing the requirement for leak detection at these "meter regulators" and include them with the sources that are covered by equipment count and population emission factors. We also suggest additional station definitions be included in the rule.

Leak definition: EPA is specifying the use of optical gas imaging instruments for leak detection at facilities. Yet it appears from the discussion in the EPA's Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document, p. 42, that the definition of leaks in the context of this equipment requires some interpretation as to detection sensitivity. We would like to see additional clarity on this in the final rule.

Response: EPA agrees, and has revised today's final rule to clarify under the natural gas distribution source category, which M&R stations are required for leak detection. Please see the comment response in Section II.F of the preamble. EPA has revised today's final rule for optical gas imaging instruments in 98.234 that any emission detected by the optical gas imaging instrument is a leak.

Comment Number: EPA-HQ-OAR-2009-0923-1015-24
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

<u>Comment Excerpt Text:</u>
It is unclear what the EPA means by "continuous." It is unclear at what point is the unit considered not in operation and therefore exempt. A general note regarding the treatment of high and low-bleed devices: PAW recommends that EPA harmonize treatment of these sources with the API Compendium.

Response: For further clarification on the meaning of "continuous" and on the methodology to estimate emissions from these sources, please see the response to EPA-HQ-OAR-2009-0923-1060-28.

Comment Number: EPA-HQ-OAR-2009-0923-1015-30
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

<u>Comment Excerpt Text:</u>
98.233(a)(1)(ii): Calculate the natural gas emissions for each continuous bleed device using Equation W-1 of this section. EPA should define "continuous."

Response: EPA agrees with the comment. For a clarification on the meaning of "continuous". Please see the response to EPA-HQ-OAR-2009-0923-1060-28.

Comment Number: EPA-HQ-OAR-2009-0923-1015-31
Organization: The Petroleum Association of Wyoming
Commenter: John Robitaille

Comment Excerpt Text:
98.232(j): Flares. PAW believes that the EPA needs to clarify the definition of this emission source. Are enclosed flares or fireboxes included in this source category?

Response: EPA has reviewed this comment and notes that the flare source in today's final rule does not include enclosed flares (e.g. incinerators) or the firebox of enclosed thermal oxidation units. These sources were deemed small and were not included in the rule. See Section 4.c. of the TSD to today's final rule for further details on the decision process.

Comment Number: EPA-HQ-OAR-2009-0923-1018-35
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (n):
During the review of 98.233(n)(2)(i) CAPP noticed that the terminology is not representative of most gas plants. The reference to de-methanizers is inaccurate as this process is typically found on natural gas liquid recovery or fractionation plants and not gas plants. Taking this into account, CAPP requests that EPA provides guidance on where the break point would be if there isn't a demethanizer at the gas plant. One option CAPP proposes would be to use the "hydrocarbon dewpoint control plant" as the break point.

Response: EPA agrees with the comment. In the absence of a de-methanizer in the gas processing facility, today's final rule has been updated to require dewpoint control point as the demarcation point.

Comment Number: EPA-HQ-OAR-2009-0923-1018-45
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.233 (w):
For 98.233(w) CAPP recommends that the EPA replaces the term "EOR injection pump" with "EOR injection system" since the use of compression or pumping is determined by the physical properties of the CO2 being injected, which can be either gaseous or supercritical dense phase which behalves like a liquid.

As with the other sections which refer to acceptable "consensus-based standards organizations"

CAPP requests that the EPA provide clarity on 98.233(w)(3) equation W-24 definition for Rc and provide a list of acceptable "consensus-based standards organizations".

Response: EPA does not agree on the use of the term "EOR injection system". EPA requires the monitoring of compressors in onshore production that deal with CO2 streams and hence the concern about gaseous phase CO2 streams in EOR operations is unfounded. Hence, EPA has retained the term "EOR injection pump" in today's final rule.

EPA does not understand what is unclear to the commenter about the definition of R_c. EPA has retained the definition of R_c as the density of EOR injection gas in critical phase. With regard to a list of consensus-based standards organizations, please see the response to EPA-HQ-OAR-2009-0923-1018-33.

Comment Number: EPA-HQ-OAR-2009-0923-1018-55
Organization: Canadian Association of Petroleum Producers
Commenter: Rick Hyndman

Comment Excerpt Text:
98.236 (f):
In reviewing 98.236(f) CAPP noticed that the requirement to report emissions separately for portable equipment for drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters is not consistent with the portable equipment definition provided in the requirements section of Sub-Part W. It is recommended that the EPA ensure that all sections within Sub-Part W are using consistent definitions.

Response: EPA agrees with the comment. In today's final rule, EPA has moved the listing of portable equipment into Section 98.232 and aligned it with data reporting requirements in Section 98.236.

Comment Number: EPA-HQ-OAR-2009-0923-1024-36
Organization: Kinder Morgan Energy Partners, L.P.
Commenter: Kim Dang

Comment Excerpt Text:
Reporting of Operational Data. The proposed rule also requires that minimum, maximum, and average throughput be reported for each "operation" of the petroleum and natural gas sector for which reporting is required under Subpart W.[262] It is not clear whether EPA intends for the term "operation" to refer to an entire facility, or to individual compressors or other subunits of a facility. Depending on which meaning EPA intends, this information could be problematic to

[262] Proposed 40 C.F.R. SECTION 98.236(d).

obtain. Just as important, the information is not useful or relevant to achieving the objectives of the Mandatory Reporting Rule; in our experience, throughput levels bear little if any relationship to the GHG emission profiles of our facilities. Accordingly, Kinder Morgan recommends that EPA omit this requirement from the final rule.

Response: EPA agrees with the commenter in regard to minimum, maximum and average throughput. Although, in today's final rule, EPA has clarified that only annual throughput using engineering estimation based on best available data is required to be reported at a facility level; the use of the term operation is inconsistent with the terminology of the rule. The throughput levels are necessary for any policy making that may require a focused approach based on the size of the facility. The commenter has not provided any data to substantiate the claim that emissions profiles are not related to facility size. Although this could potentially be true for equipment leaks, vented emissions could potentially be correlated with facility size. In the absence of any data at a national level, EPA does not see an issue with collecting some basic information that is already known to the reporter and would help in policy making.

Comment Number: EPA-HQ-OAR-2009-0923-1031-13
Organization: Anadarko Petroleum Corporation
Commenter: William W. (Bill) Grygar

<u>Comment Excerpt Text:</u>
Alternatively, if EPA determines that GHG emissions from gathering lines must be reported, we recommend that a definition for gathering lines should be included in the rule. Such a definition should specify that gathering lines: (1) are located upstream of natural gas processing plants; (2) carry produced gas; (3) do not include piping within gas plants, compression facilities, and treatment facilities; and (4) do not include transmission lines, even if located upstream of a gas plant.

Response: In today's final rule, EPA has not included gathering lines and boosting stations as an emissions source. For further information on this issue, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1035-1
Organization: Contek Solutions, LLC
Commenter: Jim Johnstone

<u>Comment Excerpt Text:</u>
Why was the AAPG-CSD Geological Provinces Code Map selected? This is a document that most operations and engineering professionals are not familiar with. Was the use of counties/ parishes considered or some other better known cartographic boundary considered

Response: The AAPG definition of basins uses county boundaries to demarcate a basin. Please see Section II.D of the preamble to today's final rule for further details on why AAPG geologic province code was the preferred definition for onshore production.

Comment Number: EPA-HQ-OAR-2009-0923-1039-34
Organization: Interstate Natural Gas Association of America
Commenter: Lisa Beal

<u>Comment Excerpt Text:</u>
Clarification is Needed on Vents Included under §98.233(p)

Vents that require measurement should be specified and clearly defined. It could be interpreted that §98.233(p)(2)(i) reference to "all" vents means only those atmospheric vents associated with reciprocating compressor rod packing, because that is the source type addressed by this section. However §98.233(p)(2)(i) references rod packing, unit isolation valves, and blowdown valves. INGAA requests that EPA specifically list the emission sources and associated vent lines to clarify required measurements for each operating mode. For example, in the de-pressurized mode, it is INGAA's understanding that leakage past unit isolation valves that find a path to atmosphere through the blowdown vent is the emission source of concern to EPA. Additional clarification and definitions should be provided to specify the emission sources and associated vents.

Vented and fugitive emissions are better defined than in the 2009 Subpart W proposal. However, consistent nomenclature is ultimately required to eliminate ambiguity, redundancy (i.e., double counting) and unnecessary confusion in rule implementation. EPA should clearly define and elaborate upon the intended source(s) and the measurement point(s) for reciprocating compressor rod-packing vents under each operating mode. These nuances and measurement criteria are not clearly defined and should be addressed in the Final Rule.

Finally, as discussed in Comment X, reporting individual compressor throughput is not feasible or practical and should be deleted from the rule

Response: EPA agrees with the commenter on the combining of multiple venting sources under the rod packing source type. EPA has revised the source type referred to as compressor vents. Also, EPA now states what vent emissions are to be monitored in each of the different modes of operations. With these changes EPA has determined there will not be any confusion over the sources of venting emissions.

EPA does not agree with the commenter on the issue about individual compressor throughput. EPA needs this information for any potential policy that wants to focus on a particular subgroup of the population of sources. EPA is asking for an engineering estimation based on best available data for this information. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1058-2
Organization: Colorado Oil and Gas Association

Commenter: Tisha Conoly Schuller

Comment Excerpt Text:
Lastly, we have concerns regarding the broad nature of the general definitions of terms as established in previous rules. We believe these should more accurately define and represent the industry's standard terminology.

Response: EPA understands the commenter's concern and has addressed or outlined why EPA does not agree with specific definitional concerns raised by commenters. For details on using industry's standard terminology, please see the responses to EPA-HQ-OAR-2009-0923-1151-8 and EPA-HQ-OAR-2009-0923-1151-17.

Comment Number: EPA-HQ-OAR-2009-0923-1151-19
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.230(a)(1) Offshore petroleum and natural gas production. The rule text includes inland waters which is not correct. In addition, Section 98.230(a)(1) and Section 98.238 both provide the definition of offshore petroleum and natural gas production. The definitions differ in that Section 98.238 states "[a]ll production equipment that is connected via causeways or walkways are one facility." This text should be added to Section 98.230(a)(1). API recommends Section 98.230(a)(1) be revised to: "Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from beneath the ocean or lake floor and that transfers such hydrocarbons to hydrocarbon to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks connected to the platform structure via causeways or walkways."

Response: EPA disagrees with the commenter on the exclusion of inland waters from offshore and has retained it in the source category definition in Section 98.230 of today's final rule. EPA agrees with the commenter regarding "walkways," and has revised today's final rule offshore source category definition in Section 98.230. EPA has also revised the definition of offshore in Section 98.238, and clarifies that lakes are included.

Comment Number: EPA-HQ-OAR-2009-0923-1151-46
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(r)(2) Population count and emission factors. Coal Bed Methane Water Well systems are not components, but instead are a type of oil production system. It would be more appropriate to create a section to address these operations. In addition, it is too vague to say "almost all CO2". A concentration should be provided.

Response: Today's final rule does not include reporting of emissions from CBM produced water. For further clarification on sampling of produced water, please see the response to EPA-HQ-OAR-2009-0923-1151-129 and Section II.E of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1151-51
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.233(u)(2) GHG volumetric emissions. The terminology utilized in this section is not representative of most gas plants, which do not utilize "de-methanizers". "De-methanizers" are typically utilized in natural gas liquid recover or fractionation plants. A more appropriate name for use in place of "De-methanizer" would be "hydrocarbon dewpoint control plant."

Response: EPA agrees with the comment. In the absence of a de-methanizer in the gas processing facility, today's final rule has been updated to require dewpoint control point as the demarcation point.

Comment Number: EPA-HQ-OAR-2009-0923-1151-61
Organization: American Petroleum Institute
Commenter: Karin Ritter

Comment Excerpt Text:
Section 98.238 Definitions.
Offshore petroleum, and natural gas production facility means each platform structure and all associated equipment as defined in paragraph (a)(1) of this section. All production equipment that is connected via causeway or walkways are one facility.
API assumes the reference to paragraph (a)(1) is referring to Section 98.230(a)(1).

Response: EPA agrees with the commenters on the incomplete reference to Section 98.230(a)(1). In today's final rule, the definition of offshore petroleum and natural gas production facility is included in Section 98.230. Hence, the commenter's issue is no longer relevant due to the change.

Comment Number: EPA-HQ-OAR-2009-0923-1167-37
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

Comment Excerpt Text:
Noble recommends that EPA conform the definitions and terminology used throughout the proposed rule to be more consistent standard industry nomenclature to prevent errors and confusion.

- The rule should be consistent in defining standard conditions for expressing gas volumes and mass and in its use of nomenclature; that is, references to industry conditions, ambient conditions, actual conditions, and STP are confusing. Noble recommends that the rule consistently apply 60 degrees F and 14.7 psia as the standard temperature and pressure; these are the units commonly used in GHG reporting protocols and referenced industry standards, and are the common units used for calibrating industry devices for custody transfer.

- 98.6 Definitions. Noble agrees with API comments concerning the definition regarding Fugitive Emissions.

Response: EPA has revised today's final rule and uses the standard conditions of 68 degrees Fahrenheit and 14.7 pounds per square inch absolute as defined in subpart A. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-8.

EPA disagrees with the proposed changes to the definition of fugitive emissions which are now referred to as "equipment leaks" in today's final rule, please see the response to EPA-HQ-OAR-2009-0923-1151-17.

Comment Number: EPA-HQ-OAR-2009-0923-1167-38
Organization: Noble Energy, Inc
Commenter: Brian K. Lockard

<u>Comment Excerpt Text:</u>

Noble requests clarification regarding definitions for "flowlines" and "intra-facility gathering lines" referenced in Section 98.230(a)(2) with the clarification that an owner/operator is responsible for reporting emissions from pipelines from the well, separator, compressor, etc. (as applicable) to the point of custody transfer.

Response: Today's final rule does not include the gathering and boosting segment of the industry. Hence the commenter clarification is not required. For further details, please see Section II.F of the preamble to today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1201-17
Organization: North Slope Burough
Commenter: Edward S. Itta

<u>Comment Excerpt Text:</u>
EPA Should Modify Reporting Requirements Applicable to Offshore Sources.

EPA's proposed definition of the "Offshore petroleum and natural gas production" source category at § 98.230(a)(1) should include all GHG emissions from offshore petroleum and natural gas production, not just those limited to the time-period when the rig is attached to the seabed floor. EPA should remove the phrase "affixed temporarily or permanently to the offshore submerged lands" from the source category definition. All emissions associated with offshore oil and gas production must be reported, not just those that occur when the source is attached to the sea floor.

EPA is proposing to amend § 98.2(a) such that the reporting requirements apply to facilities located in the United States or "under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331)", where the definition of United States includes "territorial seas".
46 EPA states, "[t]ogether these changes make clear that the Mandatory GHG Reporting Rule applies to facilities on land, in the territorial seas, or on or under the Outer Continental Shelf, of the United States, and that otherwise meet the applicability criteria of the rule."[263]

We strongly support these definition changes in order to ensure comprehensive inclusion of Outer Continental Shelf sources in the reporting requirements under Subpart W.
EPA should ensure that its GHG emissions reporting requirements from offshore oil and gas sources are comprehensive and as thorough as those required for onshore sources. Likewise, EPA should require offshore sources to use the same level of aggregation for determining reporting requirements. For example, all of an operator's offshore sources within an area that corresponds to the area of a basin onshore should be required to aggregate emissions in order to determine whether reporting requirements are triggered. Offshore oil and gas sources are significant contributors to GHG emissions and must be held to the same standard as onshore sources.

Response: EPA has determined that commenters' assumptions and interpretations of the proposed rule were not as intended by EPA and led to the view that drilling rigs not installed on production platforms are reported under subpart W, or that other mobile sources of emissions have to be reported. Subpart W applies predominantly to those production platforms reporting activity date to the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) during a Gulfwide Emissions Inventory Study. This data is reported in the GOADS software, and BOEMRE converts it to emissions and reports this data publicly. While BOEMRE does research activity data on mobile sources (air and marine) as well as geogenic and biogenic sources, and estimates the emissions from those, the data is not collected in a thorough survey of every mobile source operator as platform data is collected. Therefore, today's final rule retains the definition of platforms subject to reporting under this subpart to include those reporting activity data in a GOADS survey, plus platforms in state and non-Gulf of Mexico Federal waters. Finally, EPA clarifies that emissions sources not on platform facilities and mobile sources do not have to be reported in today's final rule.

Comment Number: EPA-HQ-OAR-2009-0923-1201-22
Organization: North Slope Burough
Commenter: Edward S. Itta

<u>Comment Excerpt Text:</u>

[263] See 75 FR 18611, April 12, 2010.

EPA should conduct a thorough investigation of geographic boundaries and organizational boundaries (e.g., contractual relationships) in this industry sector to determine the best reporting entity. As an example, CCAR is considering two options for defining a facility for the natural gas transmission sector: (1) using the industry descriptions as portrayed in the North American Industrial Classification System (NAICS); and (2) using the regulatory definitions from the National Emission Standard for Emission of Hazardous Air Pollutants (NESHAPs) promulgated by EPA[264] reporting rules, even if it is not feasible to include requirements in this version of the rule.

Response: EPA reviewed both NAICS and NESHAP definitions in lieu of the Subpart W definition for transmission segment and has determined that the Subpart W definition is robust enough for the purposes of the MRR. Please see the responses to EPA-HQ-OAR-2009-0923-1024-14 for NAICS and EPA-HQ-OAR-2009-0923-3568.4-4 for NESHAP definitions.

Comment Number: EPA-HQ-OAR-2009-0923-1206-64
Organization: Gas Processors Association
Commenter: Jeff Applekamp

<u>Comment Excerpt Text:</u>
This section requests "minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section." This is a very vague request and has no apparent meaning for most of the operations described in (a)(1) through (a)(8). In addition, this information does not appear to be useful in determining or understanding the GHG emissions information that is otherwise reported. Therefore, we recommend that paragraph (d) should be deleted.

Response: Please see the response to EPA-HQ-OAR-2009-0923-1024-36.

Comment Number: EPA-HQ-OAR-2009-0923-1298-10
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

<u>Comment Excerpt Text:</u>
Section 98.2: Who Must Report The amended text of the proposed rule under the heading "Who must report?" in Section 98.2(a) states:

The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility [emphasis added]

It is IPAMS' expectation that either the owner or operator would report emissions, not both

[264] Discussion Paper for a Natural Gas Transmission and Distribution Greenhouse Gas Reporting Protocol, Final Draft Report, Prepared for the California Climate Action Registry and World Resources Institute by URS Corporation and The LEVON Group, June 6, 2007, pp. 4-20.

parties, and that EPA did not intend for emissions to be double counted. Moreover, due to the nature of the oil and gas production industry, there may be numerous owners of a facility that do not have day-to-day control of a facility's operations. Therefore, IPAMS requests that EPA clarify Section 98.2(a) to state that the requirements of this part apply only to the operator since this is the party that has control over a facility's operations and therefore its GHG emissions.

Response: Owners or operators who are subject to reporting under today's final rule must appoint a designated representative and only one designated representative who is responsible for submitting reports. Please see Section 98.4 of today's final rule. It is the responsibility of owners or operators to select that designated representative for reporting purposes as provided in Section 98.4. The designated representative (DR) is the entity that is responsible for submitting the emissions data pursuant to today's final rule. Please see the response to EPA-HQ-OAR-2009-0923-1024-16.

Comment Number: EPA-HQ-OAR-2009-0923-1298-5
Organization: Independent Petroleum Association of Mountain States
Commenter: Kathleen M. Sgamma

Comment Excerpt Text:
EPA should use the established CAA definition of a facility.

Response: EPA does not agree with the commenter. For further details, please see Topic 1: GHG Reporting under Subpart W and the Consolidated Appropriations Act in Volume 9 of the Response to Comments and response to EPA-HQ-OAR-2009-0923-1044-1.

Comment Number: EPA-HQ-OAR-2009-0923-1305-10
Organization: BP America, Inc.
Commenter: Karen St. John

Comment Excerpt Text:
Section 98.230(a)(4) Onshore Natural Gas Transmission Compression

It is not clear where onshore natural gas transmission compression begins and modifying the description to be consistent with the definition of this segment in Subpart HHH of the NESHAP regulations is recommended.

D. Definitions and Terminology

BP requests that EPA conform the definitions and terminology used throughout the proposed rule to make it more consistent with that used by industry. An example of the use of terms that are not those commonly used by industry or equipment vendors, is the rules use of "high bleed" devices rather than "high bleed" controllers, which is the term recognizable to equipment vendors.

However, even more fundamental than the terminology issues, is the proposed rule's confusing mix of conditions for expressing gas volumes and mass. The MRR uses, in different parts of the existing rule (Subparts C, Y, NN, PP) as well as the proposed Subpart W, industry conditions, ambient conditions, actual conditions and STP. EPA should consistently apply industry standard conditions (60 degrees F and 14.7 psia) throughout the MRR since these are the units used in all the referenced industry standards and are the common units used for calibrating industry devices for custody transfer.

In addition, applying the emission equations in the proposed Subpart W produces a mix of emission results. For example, Equation W-1 results in natural gas emissions (scf/yr) from high bleed pneumatic devices, while Equation W-2 results in annual metric tonnes of CO2 equivalent emissions from low bleed pneumatic devices. Although, 98.233(u) Equation W-22 converts natural gas volumetric emissions to GHG volumetric emissions and 98.233(v) Equation W-23 converts GHG volumetric emissions to GHG mass emissions as CO2e, the mix of units resulting for individual source types impedes comparison among sources. For consistency with existing MRR reporting requirements and for comparison among emission source types, all emission equations should result in metric tonnes of GHG emissions by GHG type (e.g., CO_2, CH_4, and N_2O) and then apply Equation A-1 to convert to CO_2e emissions. Consistent use of industry standard conditions for all calculations with conversion of volumes to metric tonnes for each quantified source will ensure that annual GHG emissions are properly quantified and reported.

Response: EPA has reviewed this comment. EPA reviewed both NAICS and NESHAP definitions in lieu of the Subpart W definition for transmission segment and has determined that the Subpart W definition is robust enough for the purposes of the MRR. Please see the responses to EPA-HQ-OAR-2009-0923-1024-14 for NAICS and EPA-HQ-OAR-2009-0923-3568.4-4 for NESHAP definitions.

EPA has revised today's final rule and uses the standard conditions of 68 degrees Fahrenheit and 14.7 pounds per square inch absolute as defined in subpart A. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-8.

EPA disagrees with the comment about using standard industry terminology and the consistency of the equations with existing MRR reporting requirements. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-8.

Comment Number: EPA-HQ-OAR-2009-0923-1306-24
Organization: DTE Energy
Commenter: Gregory L. Ryan

<u>Comment Excerpt Text:</u>
Equations W-20 and W-21 refer to ambient pressure. DTE Energy requests that EPA clarify what is meant by ambient pressure to avoid confusion.

Response: EPA has reviewed the comment. However, in today's final rule EPA uses actual conditions for equations W-20 and W-21. Since conditions at which emissions occur or are monitored are not always the same as ambient conditions, the term actual conditions better represent the conditions whether operational or ambient.

Comment Number: EPA-HQ-OAR-2009-0923-3568.4-6
Organization: American Petroleum Institute
Commenter: Karen Ritter

Comment Excerpt Text:
On Subpart W, API requests that EPA conform the definitions and terminology used throughout the proposed rule to make them more consistent to those used by industry. This is particularly applicable to the rules confusing mix of expressions used for gas volumes and mass. For example, the proposed rule uses in its different sections, industry conditions, ambient conditions, actual conditions and STP. API continues to recommend that the rule should stick with, quote, “industry standard conditions” (60°F and 14.7psia) since these are the units used in all the referenced industry standards and are the common units used for calibrating industry devices for custody transfer.

Response: EPA has ensured that the relevant condition specifications are used for each of the Subparts as required. Within Subpart W, EPA has reviewed and revised the temperature and pressure conditions to specify either actual or STP as appropriate. For example, certain emissions such as blowdowns are calculated at actual conditions and finally need to be converted to STP conditions for reporting to EPA. Here the use of both actual and STP conditions is required in the rule. Finally, emissions calculated in actual conditions are converted and reported to the EPA in standard temperature and pressure. For further details, please see the response to EPA-HQ-OAR-2009-0923-1151-8.