



American
Petroleum
Institute



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Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Docket No. EPA-HQ-OAR-2023-0234

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the American Fuel and Petrochemical Manufacturers (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (proposed on August 1, 2023). For perspectives of offshore operators, the Industry Trades encourage EPA to also review the Offshore Operators Committee (OOC) letter and incorporate them by reference herein. With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to simultaneously address EPA's goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

The oil and natural gas industry has participated as key collaborative stakeholders, advancing the EPA Greenhouse Gas Reporting Program (GHGRP) since its inception by contributing expertise and proposing alternatives that reflect the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have focused on providing information that will help inform decision makers and the public about various challenges to data collection and reporting required by the rule, which includes safety, accuracy, and feasibility concerns, as well as the need to protect sensitive information and to ensure that reporting requirements are placed on the correct reporters.

These comments on EPA's proposed revisions to Subpart W reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

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INDUSTRY TRADES' INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the [Compendium](#) (November 2021), methodologies to estimate and measure greenhouse gas emissions are continually evolving.

The **American Exploration & Production Council (AXPC)** is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **Petroleum Alliance of Oklahoma** (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse

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gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The Industry Trades appreciate EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize changes to Subpart W that improve accuracy without imposing undue burden on the industry, reflect technological and scientific improvements in methodologies, and incentivize the industry's ongoing efforts to reduce emissions.

Docket ID No. EPA-HQ-OAR-2023-0234

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The Industry Trades' Comments on EPA's Proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems"

Docket ID: EPA-HQ-OAR-2023-0234

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Summary of Priority Items

The Industry Trades support certain aspects of the proposed revisions to Subpart W and remain committed to working with the Environmental Protection Agency (EPA) and the Administrator to improve the accuracy of Subpart W reporting in a cost-effective manner, while encouraging continued progress toward reducing greenhouse gas (GHG) emissions. The Industry Trades support accurate emissions reporting for many reasons, however it is particularly important given that reported emissions will form the basis of assessed methane fees as a Waste Emissions Charge (WEC), implemented under the Inflation Reduction Act (IRA). As such, these proposed changes create a potentially significant financial impact on the Industry Trades. Therefore, the Industry Trades provide these comments with a goal of improving accuracy of reported emissions through requirements that are appropriate, implementable, and reflective of actual emissions.¹ The comments herein focus on technical and feasibility challenges with specific provisions that EPA included in the proposed Subpart W rule revisions, while providing viable alternatives that support accurate emissions reporting.

The Industry Trades continue to strongly encourage EPA to find ways to make Subpart W less prescriptive and therefore better poised to not just accommodate but encourage the use of rapidly evolving technologies to detect and minimize emissions.

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. **Achieve greater inter- and Intra- agency regulatory harmonization and coordination:**

There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

- a. EPA – New NSPS OOOO b/c regulations
- b. EPA – Revisions to GHG Subpart W methane reporting
- c. EPA – Pending Methane Emissions Reduction Plan (MERP) implementation regulations
- d. Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
- e. DOT/PHMSA – LDAR Rule
- f. DOI/BLM – Waste Prevention Rule
- g. DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
- h. DOE – Differentiated Gas Framework
- i. State Department – International methane MRV standard (with DOE)
- j. State Department – Global discussions on an EU Import standard and global methane policy

¹ Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments does not necessarily reflect the individual comments' importance to the Industry Trades and their members. The Industry Trades believe all of its comments will help ensure the rule's integrity and deserve serious consideration.

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Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

In addition, many states – especially New Mexico and Colorado – have already implemented regulations to mitigate emissions across the oil and gas industry; these likely conflict with the final NSPS OOOOb, EG OOOOc and Subpart W reporting requirements.

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc “Methane Rules” and the GHGRP itself. Below are a few examples that are articulated in our comments:

- “Other large release events” should be governed by the Methane Rules Super Emitter Response Program (“SERP”), not by an additional and separate Subpart W notification process.
- The “Other large release event” threshold for pipelines should align with the PHMSA incident threshold.
- Compressor vent measurements should align with the Methane Rules. Subpart W should not mandate additional measurements for those sources.
- Flare requirements should not extend beyond 60.18 “General control device and work practice requirements” and the Methane Rules.
- Combustion emissions for all oil and gas segments should be reported under Subpart C, which is the subpart under which *all other industries* report fuel combustion emissions.

2. Incentivize Cost-Effective Advanced Methane Detection through Technology Agnostic

Rules:

Advanced methane detection technologies and flexibility to implement them are critical to the industry’s ability to fully realize methane emissions reductions. Many operators have invested in technological advancements and have deployed and tested the technologies over many years, demonstrating the success of advanced programs and reaching a firm understanding of their operation and deployment. If this component of the suite of methane rule makings, including in Subpart W, is not expanded, the remaining rules will fail to realize the emission reduction goals.

3. Accommodate Empirical Data, as a Demonstration of Emission Reductions:

Provisions must be built into the Subpart W rule so that each operator can demonstrate actual reductions; this would promote consistency, transparency, and accuracy in emissions reporting. For example, reporters are precluded from using readily available empirical data (such as engine performance tests) and are instead required to use static emission factors that were based on limited data sets, which will not reflect emissions reductions and will disincentivize emission reductions. The Industry Trades have noted throughout our comments where EPA must adjust the rule to accommodate empirical data.

4. Maintain EPA’s GHGRP and Subpart W within it as the Authoritative Source of Reported Emissions:

There are increasing instances of conflict between Subpart W methodologies with those of permitting agencies, which also conflict with current and proposed LDAR requirements and other

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state and federal GHG reporting structures. EPA must strive for consistency across all GHG reporting frameworks in order to promote stakeholders' trust and confidence in the data.

In addition to the high priority items listed above, the summary below includes the key comments that are generally applicable to many of EPA's proposed revisions to the Subpart W rule:

- **Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions.** This overarching theme applies to numerous proposed requirements, especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices. The Industry Trades have proposed more efficient and feasible alternatives.
- **EPA has not provided qualitative and quantitative justification to rationalize the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.** The rule explicitly references existing definitions of facilities in 40 CFR 98 Subpart W, which includes basin-level reporting for the production and gathering and boosting segments. In this proposed rule, EPA has not clarified how its new proposed level of disaggregated reporting to the site-level results in additional value in understanding the key sources of emissions from a basin. A survey performed by API indicates that the proposed Information Collection Request (ICR) pertaining to the proposed rule significantly underestimates the burden for the impacted sectors that would be required to report individual site level emissions and site IDs. Due to the magnitude of the difference, EPA should provide justification in the form of both qualitative and quantitative results of the costs and benefits of this proposed change and how it aligns with the IRA.
- **Generally, the Industry Trades support the optional use of measured data in addition to EPA or company developed emission factors, when the measured data are appropriate.** Allowing reporters the option to use measured data or emission factors (EPA or company-developed) would increase data accuracy and avoid disincentivizing emission reduction measures. While EPA is increasing the sources for which direct measurement is allowed, there are still some methodologies which only allow the use of prescriptive emission factors and parameters with no alternative options (e.g., flare methane destruction efficiency, fraction of un-combusted gas from engines, crankcase venting). While we support the option to use default emission factors and parameters, requiring reporters to use prescriptive emission factors and parameters in lieu of an option to use directly or representatively measured data disincentivizes deployment of emission reduction measures. Additionally, there are some sources where measured data is required to be used, even if the measured data is infeasible, incomplete or potentially unreliable (e.g., flare flow and composition monitoring, mud degassing methane content). EPA should allow operators to utilize the growing number of technologies with quantification capabilities to report empirical data for source categories covered under Subpart W.
- **Monitoring, measurement or inspection requirements (e.g., flare monitoring, etc.) included in Subpart W should be consistent across other air quality programs.** The Industry Trades are concerned with potentially conflicting monitoring or other compliance requirements between the Greenhouse Gas Reporting Program (GHGRP) and future air quality rulemaking under New Source Performance Standards (NSPS) or other air quality programs under EPA's office of Air and

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Radiation. The Industry Trades are recommending that EPA remove prescriptive monitoring, sampling or inspection requirements from the GHGRP and instead reference data made available through requirements in other existing regulations. Furthermore, the Industry Trades suggest that EPA not finalize changes to Subpart W until such time that NSPS OOOOb and EG OOOOc have been finalized, and give another opportunity to provide comments on the proposed updates to Subpart W. It is important to the Industry Trades that there is consistency as opposed to conflicting requirements between the GHGRP and future and current rulemaking under other air quality regulatory programs. Finally, the Industry Trades wish to make clear that monitoring methods should not define emission reporting parameters.

- **EPA should avoid any potential double-counting of emissions across source types. The Industry Trades have identified specific areas with the potential for double-counting.** Since it is expected that the GHGRP will be used to determine associated fees within a methane-fee environment, the Industry Trades are extremely concerned about any source and methodology which could result in double counting emissions, and therefore, double fees. Categories that are particularly susceptible to potential double counting are other large release events and unlit flares; and even between flares and unlit flares, where the proposed Tier 3 destruction efficiency for flares includes unlit flares.
- **EPA must set a period over which submitted GHG reports are considered “final” now that reported emissions will be used as a basis for methane fees.** The Industry Trades are concerned about having to resubmit reports for administrative errors or small corrections in emissions given EPA’s historical practice of continually submitting questions regarding previously submitted reports. This would lead to an unworkable situation where additional fees will have to be levied or credited for minor changes in emissions in a methane-fee environment. The Industry Trades recommend a 5% facility-wide reported methane emissions error threshold and only require corrections for emission inventories in the last three full data years.

The following key comments reference specific high priority items that pertain to requirements in the Subpart W proposed rule amendments:

- **EPA’s tiered approach to flare “combustion efficiency” is flawed and is not supported by the data cited by EPA in the Technical Support Document.** The Industry Trades are concerned that EPA proposes to override decades of precedent on oil and gas flare monitoring and operation established in federal and state regulations, permits, manufacturer guarantees, and performance tests based on the results of just one limited study. As such, the Industry Trades are requesting EPA to allow performance test data for flare methane destruction efficiency, rather than inappropriate National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements, as aligned with EPA’s intent to incorporate empirical data. Further and importantly, the Industry Trades have provided additional data to supplement its position that flare “combustion efficiency” should be a minimum of 95%, or arguably even higher based on data from 132 flares tested in the Permian and Bakken. Please refer to Section 3.8.4.4.
- **EPA’s requirement to directly meter or use continuous parametric monitoring to estimate flare volume is technically and economically infeasible, and may actually lead to reporting inaccuracies, especially for low-flow streams.** The Industry Trades propose that EPA allows

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reporters the option to continue to use engineering estimates for flare volume. Please refer to Section 3.8.1.

- **There are significant concerns regarding the “other large releases” category relating to third-party reporting, the lack of clarity around what is considered “credible” information, and the thresholds proposed for the source category.** The Industry Trades are concerned that unqualified third-party reports could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear and consistent guidelines across regulatory programs on who would be qualified to provide third-party reports (i.e., the necessary expertise, qualifications, methodology, timeline of sharing detections, etc.). The Industry Trades are also concerned that the use of any credible information may lead to reporters inadvertently using invalid data sources, which can lead to inaccurate emissions and disparity among reporters. Further, EPA’s requirement to assume a duration of 182 days if no data is available for the release’s start or end date is overly conservative. For these reasons, the Industry Trades request EPA to clearly define the scope of credible information. Further, the thresholds of 100 kg/hr. OR 250 mtCO₂e would make events with relatively small durations reportable, which does not appear to be EPA’s intent to capture large releases. As such, the Industry Trades request that the thresholds be changed to reflect BOTH a rate and an emissions level per event; at a minimum, the threshold should be changed to ‘100 kg/hr. AND 250 mtCO₂e’ (i.e., the 100 kg/hr. rate needs to be paired with a duration of at least 100 hours in order to be equivalent to 250 mtCO₂e). Please refer to Section 3.11.1, as well as API’s comments in response to Docket ID EPA-HQ-OAR-2021-0317, Section 1 (also included in Annex C of this letter).
- **EPA’s assumption that improperly seated thief hatches result in a zero percent control efficiency for controlled tanks is overly conservative and not considered in the TSD. Further, EPA’s proposed method to calculate the duration of open thief hatches over-estimates emissions from this source.** The Industry Trades propose that EPA use a bifurcated approach for thief hatches that accounts for when they are fully open or improperly seated, which would have lower expected emissions. Please refer to Section 3.6.2.
- **While the Industry Trades support the flexibility to measure GHG emissions from intermittent bleed pneumatic devices, we request that EPA retain the option to use default population emission factors for sources subject to other regulatory programs.** The Industry Trades do not agree with the requirements to measure and monitor emissions from intermittent bleed devices, especially for sources that will be phased out under the impending methane rules. Please refer to Section 3.1.
- **The Industry Trades request that EPA change both the name and definition of “centralized oil production site” in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production for consistency and to reflect how the industry owns and operates these facilities.** EPA has incorrectly included centralized production facilities with gathering and boosting, but should instead include them in the production segment where they belong. The Industry Trades also strongly recommend that EPA delete “associated with a single well pad” from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion. Please refer to Section 3.16.

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

Docket ID: EPA-HQ-OAR-2023-0234

The comments presented below are arranged by the order of citation in the proposed revisions to the “Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.”

1. Subpart W and the Waste Emissions Charge Program

EPA must present a clear rationale for adding an additional layer to sub-facility-level (i.e., site level) reporting to the onshore production and onshore gathering and boosting segments.

EPA explains in the Proposed Rule that under the current Subpart W, “GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source.”² According to EPA, this reporting method “can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency.”³ To resolve those “challenges,” EPA proposes “to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.”⁴ Furthermore, EPA proposes to require several new site-specific data elements to be reported, including reporting information for individual well identification numbers, well pad identification numbers, and gathering and boosting site identification numbers.⁵ In other words, EPA proposes to require site specific reporting in addition to facility-level aggregate reporting.

EPA correctly explains in the Proposed Rule that “[u]nder CAA section 136, an “applicable facility” is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution).”⁶ As currently defined for onshore production and gathering and boosting, facilities in these segments are generally defined as the equipment located in a single hydrocarbon basin under common ownership or control. The meaning of the term “applicable facility” is key to implementation of the WEC because the applicability of that program and potential fees are determined on an “applicable facility” basis.⁷ In the IRA, the definition of an “applicable facility” in the onshore production and gathering and boosting refers to a facility within the applicable segment, as defined in 40 CFR Part 98 at the time of passage of the bill.

Unless EPA proposes updates to facility definitions in 98.238, reporting should remain at the basin-level. Even if EPA were to propose new facility-level definitions in a future rulemaking, there are remaining concerns discussed below.

² 88 Fed. Reg. at 50309.

³ *Id.*

⁴ *Id.*

⁵ *Id.* at 50309-10.

⁶ 88 Fed. Reg. at 50285.

⁷ CAA § 136(c), (e).

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EPA's justification for the proposed sub-facility-level reporting requirements is fundamentally flawed because the Agency wholly fails to consider whether the proposed requirements will be adequate to support applicability and fee determinations under the WEC. As noted above, EPA asserts that the new sub-facility-level reporting requirements are needed because the current Subpart W approach "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."⁸ These reasons have nothing to do with the primary purpose of this rulemaking – to satisfy the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.⁹ Although not related to the WEC, in EPA's Response to Comments in 2009, EPA agreed that oil and natural gas is to be reported at the "upstream" level because further disaggregation would be burdensome to the reporter.¹⁰

In fact, nowhere in the Proposed Rule does EPA acknowledge that a key driver (if not the key driver) of the proposal is to generate the facility-specific data needed to implement the WEC, nor does EPA provide any analysis or assessment as to whether the new proposed sub-facility-level reporting requirements will be sufficient for that purpose. Unless corrected in a supplemental proposal, that failure to acknowledge and assess a key factor in the rulemaking will render the final rule arbitrary and capricious. *See, e.g., Motor Vehicle Mfrs. Assn. of the United States v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has ... entirely failed to consider an important aspect of the problem.") The WEC is based on the existing definitions of facilities subject to Subpart W; for that reason, there is no statutory basis to require reporting on a sub-facility-level basis. Basin-level data satisfies the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.

EPA does not explain how the direction in CAA§136(h) in conjunction with CAA § 114 provides authority for EPA to develop extensive requirements in order to collect empirical data.

The text of CAA §136(h) provides:

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

Thus, EPA is charged with updating Subpart W reporting to allow for the use of empirical data in reporting methane emissions that will ultimately become the emissions input to calculating the WEC. EPA does not explain in the Proposed Rule how this new congressional direction, layered on top of CAA § 114, provides authority for EPA to develop extensive requirements for installation of monitoring

⁸ *Id.* at 50309.

⁹ CAA § 136(h).

¹⁰ “. . . oil and other petroleum products must be reported by refineries, importers, and exporters under Subpart MM. For the proposed rule, EPA decided to require reporting at these points because reporting at natural gas and oil production wells would have been too burdensome and would have resulted in too many reporting facilities, with no improvement in data accuracy.”, <https://www.regulations.gov/document/EPA-HQ-OAR-2008-0508-2256>.

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equipment or sampling to acquire empirical data. In the preamble to this Proposed Rule, EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program. Furthermore, in the discussion of new requirements for individual sources under Subpart W, EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee. Before issuing a final rule, EPA must provide a thorough discussion of how this limited change to its statutory authority in the IRA provides a basis for these extensive revisions.

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

As noted above, key elements of the Proposed Rule are not adequately explained or supported because EPA failed to assess or explain how the proposed new reporting requirements square with the various elements of the WEC. A fundamental aspect of this issue is the fact that the information generated under Subpart W will be used for wholly different purposes under the WEC than it previously was under Subpart W alone. In particular, the emissions information reported under Subpart W will have new and significant legal ramifications because it will be used to determine the applicability of fee determinations under the WEC. So, Subpart W will be extended from a program that provides emissions data for informational purposes to support the development of the national Greenhouse Gas Inventory by EPA into a program that also serves as the compliance assurance component of the WEC. Simply put, this change in the rule now has financial implications for companies.

That expansion in the basic purpose of Subpart W is highly relevant to the Proposed Rule and in meeting EPA's obligation to revise Subpart W to "allow owners and operators of affected facilities ... to demonstrate the extent to which a charge under subsection (c) is owed."¹¹ For example, as explained above, the extent to which "other large release events" should be reported under Subpart W must be established with an eye toward the relevance of the reported information in assessing the applicability and substantive requirements under the WEC program. The same is true of the other "gaps" in Subpart W that EPA proposes to fill in the Proposed Rule.

The rule must also allow an option to use directly or representatively measured data under all sources to demonstrate reductions in emissions. As proposed, not all source categories allow the use of directly measured data to demonstrate true reductions and improvements (i.e., flare combustion efficiency, crankcase venting, and any other area in the rule where reporters are required to use emission factors instead of having the option to directly measure).

Also, emissions information from oil and gas operations is developed to satisfy a wide range of regulatory and non-regulatory obligations beyond the WEC – including to show compliance with the NSPSs and NESHAPs for such operations and to satisfy emissions reporting obligations (e.g., the SEC's proposed disclosure rule). EPA must clearly specify the information needed to implement the WEC and prevent collateral challenges to WEC compliance based on information generated for other purposes under other regulatory programs.

In short, Subpart W is now unique among the GHGRP subparts in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other

¹¹ *Id.*

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subparts. As a result, EPA now must consider the implications under the WEC program of all Subpart W requirements and explain how Subpart W and the WEC will be integrated into a consistent, coherent, and workable program. EPA's failure to do so in the Proposed Rule constitutes a failure to consider a highly important aspect of the proposal and prevents interested parties from fully understanding, assessing, and commenting on the proposal.

2. 40 CFR Part 98, Subpart A

2.1 Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

The Industry Trades acknowledge that EPA has attempted to address concerns over the requirement for a new owner/operator of a reporting facility to be responsible for historical GHGRP reporting prior to the facility's acquisition date by proposing assignment of a "Historical Reporting Representative."

The Industry Trades reiterate concerns highlighted in our October 6, 2022, letter¹² that a new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of any reporting facility. There are several complicated factors that EPA has not addressed as part of this rulemaking.

Proposing a "Historical Reporting Representative" does not guarantee the accuracy of historically reported information. First, there remains no guarantee that the selected representative would maintain access to the critical data systems used to generate the information used for historical GHG reports; once an acquisition is complete, those historical data systems are often no longer accessible by the purchaser (and in some cases, no longer maintained by the seller). While the "Historical Reporting Representative" could provide some anecdotal context around previously submitted reports, there is no guarantee that the "Historical Reporting Representative" would have had "primary responsibility for obtaining the historical information" which would not meet the threshold required for certification from a Designated Representative.¹³ This is particularly true when assets are acquired from economically distressed companies which might no longer have any personnel who were involved in any of the historical GHG reports still on staff.

Furthermore, EPA has requested updates to previously submitted reports dating back 5 years and beyond; in many instances, the requested updates do not impact reported emissions and are often simply requests for clarification on certain reporting elements which are solely administrative in nature (e.g., a rolled up total of "Producing" wells in Table AA.1.ii does not match the count of wells labeled

¹² API Comments to EPA October 6, 2022. <https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0322>

¹³ 40 CFR 98.4(e)(1): Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. 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. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

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“Producing” in Table AA.1.iii). New owners or operators should not be required to update or submit reports for administrative issues which do not impact reported emissions, and EPA should limit the timeframe under which they request additional information or request re-submittals (see Section 2.2, ‘Addressing “Substantive” Errors in a Methane-Fee Environment’ below).

Currently within EPA’s E-GGRT system, there is no way for a new company to access the reports that were previously submitted by the previous owner. Many times when files are transferred, files are missed or it is not clear what was actually submitted by the company. The new owner may not have access to the previous 5 years of submittals and will likely not have access to all the supporting historical records required to generate the report.

The Industry Trades are recommending that EPA require new owners to be responsible for resubmitting or correcting reports only after the point of acquisition, which is further addressed in the below section, ‘Addressing “Substantive” Errors in a Methane-Fee Environment.’

2.2 Addressing “Substantive” Errors in a Methane-Fee Environment

A de-minimis threshold and timeframe must be established for errors to be considered substantive.

The Industry Trades reiterate our October 2022 comment that a threshold must be developed by which an error is to be considered substantive. As currently codified, the definition of “Substantive Error” is overly broad; any change, including those that are administrative in nature that do not impact methane emissions, could trigger a re-submittal. Since it is likely that future rulemaking will result in operators paying a methane fee on emissions, it will become increasingly critical for EPA to:

1. Determine a de-minimis “substantive error” threshold for methane emissions that excludes administrative errors that would result in a re-submittal;
2. Limit the timeframe in which EPA can determine that a “substantive error” has occurred; and
3. Limit EPA’s validation of re-submitted reports to only the initial potential error.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. Furthermore, as reported emissions result in more financial impacts, the required levels of burdensome review for a change in reported data will increase, even if a change does not result in a change in emissions. For these reasons, Industry Trades are recommending that EPA develop a de minimis threshold for “substantive errors” of 5% of an applicable facility’s reported methane emissions. This 5% de minimis threshold for total GHG emissions is aligned with a level of emissions change that many companies use for updating their corporate emissions due to errors and/or acquisitions/divestitures in accordance with the WRI/WBCSD GHG Protocol. While EPA may not know the scope of a possible error when initially requesting additional information, the reporter should have the option to not re-submit the report if an error is found to be below the de minimis threshold, and operators can provide the supporting information in their response to EPA through E-GGRT.

Finally, the Industry Trades are recommending a limit to the timeframe in which EPA can determine that a substantive error has occurred. The Industry Trades recommend that EPA limit the timeframe in which a “substantive error” can result in a requirement to resubmit a prior year’s report to no more than three years, consistent with the record retention requirement in 40 CFR 98.3(g). Further, for re-submittals, EPA should limit the validation to the requested source(s) for which the substantive error was identified. This

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will avoid the burden of the current practice of EPA re-opening inquiries for other sources that previously have already been addressed by the reporter. This still allows EPA plenty of time for review and questions.

3. 40 CFR Part 98, Subpart W

3.1 Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

Under NSPS OOOOb and EG OOOOc (§60.5390b and §60.5394c), EPA has proposed a zero-emitting standard for natural gas driven pneumatic controllers that, if finalized as proposed, will result in the elimination of methane venting from natural gas driven pneumatic devices, with the exception of those located in Alaska at a site without power. As part of separate comments on the EPA proposed NSPS OOOOb and EG OOOOc, several of the Industry Trades recommended there be limited exceptions to the zero-emitting standard where not feasible and to use the leak detection and repair program monitoring to confirm proper functioning of pneumatic controllers EPA should consider the requirements and timelines that it is proposing across NSPS OOOOb, EG OOOOc, and Subpart W to promote efficiency across the programs and focus on emission reductions.

Given the potential changes to pneumatics under OOOOb and OOOOc, the time period and practicality of using several of the proposed methods for Subpart W may be minimal. As proposed, Method 1 in §98.233(a)(1) requires installation of permanent flowmeters on equipment that will eventually be removed from service. As proposed, Method 2 would require direct measurements on all natural gas driven pneumatic devices over a several year period that corresponds to expected timelines under NSPS OOOOb and EG OOOOc. Method 2 would require purchasing new measurement equipment and training technicians on their operation, which would have a limited window of use with timelines in NSPS OOOOb and EG OOOOc.

Based on the complexities noted above, Method 3 will likely be utilized by many operators for Subpart W reporting. While the Industry Trades support the intent of proposed Method 3, this option also currently includes undue burden for estimating emissions from devices that will, for the majority, not be in operation within the next decade.

Therefore, the Industry Trades offer the following recommendations, which we describe in more detail in the following comments:

- For natural gas driven pneumatic controllers that are not measured under Method 1 or Method 2 or monitored for proper function under Method 3, EPA should allow the use of the single whole gas population emission factor for intermittent-bleed devices (refer to Section 3.1.1).
- EPA should allow an optional estimation of properly operating intermittent-bleed pneumatic controllers using equipment-specific engineering calculations, or a facility-specific properly operating emission factor based on direct measurement. We elaborate on the details further in Section 3.1.3.
- Amend the proper functioning and malfunctioning emission factors for intermittent-bleed devices to include all relevant studies (refer to Section 3.1.3).

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- Allow the duration of an intermittent-bleed device malfunction to be determined by repair date or the last monitoring survey (refer to Section 3.1.4).

Note that both Method 2 and 3 provide time horizons for conducting flow measurements or monitoring surveys up to a 5-year cycle depending on the industry segment in which a facility is located. For both onshore production and gathering and boosting, EPA has proposed that operators measure/monitor approximately the same number of devices each year. This timing directly coincides with the implementation of NSPS OOOOb/EG OOOOc and complicates how an operator might track monitoring or measurement results as equipment changes at a facility. Over time, it may be impossible to monitor the same count year-over-year as the total count of natural gas driven devices will reduce over time.

3.1.1 Retain Whole Gas Emission Factor Approach for Intermittent-Bleed Devices

While operators should have the *option* to measure and monitor emissions from those devices, it should not be *required* for sources expected to be phased out as required in other regulatory programs, as this would result in undue capital investment without creating additional value to stakeholders. The proposed methods are highly inefficient and unnecessary considering the required 15-minute measurement time per device or monitoring each device (i.e., OGI or Method 21 screening) for 2 minutes or until a malfunction is identified. The additional burden is not justified considering:

- Any accuracy gain is expected to be temporary considering that proposed federal air quality rules require all pneumatic devices to be transitioned to zero emitting devices;
- Continuous bleed pneumatic devices, a higher emitting source, are allowed to report using an emission factor approach; and
- It penalizes operators who have invested in cleaner technology by replacing continuous high-bleed controllers with intermittent-bleed devices by requiring them to be measured or monitored.

Therefore, **EPA should retain the option to use the default whole gas population emission factor for intermittent bleed pneumatic devices**, as has been proposed under Method 3 for both continuous high- and low-bleed pneumatic devices. Consistent with the derivations used for new emission factors for high and low bleed continuous pneumatic controllers in Table 5-11 of the Technical Support Document for this Rule, EPA suggests the use of 8.8 scf/hr./device for intermittent bleed pneumatic devices, based on a meta-analysis of a variety of field studies. Moreover, many operators are actively working toward voluntarily eliminating most of these sources as they either fall under current or anticipated upcoming state or federal regulations requiring either source control or a zero emissions standard for this equipment. Implementing a burdensome monitoring program for sources that will soon become less significant doesn't make sense. Operators have collectively performed thousands of retrofits to convert continuous high-bleed pneumatic devices into intermittent bleed devices. Operators who acted swiftly should not face more burdensome greenhouse gas accounting requirements, nor should further near-term retrofits be discouraged by imposing disproportionate accounting burdens.

3.1.2 Method 2 – Suggest Improvement in Measurement Cycle and Alternative Approach

The Industry Trades generally support EPA's Calculation Method 2 to distribute measurement campaigns over multiple years where flow monitors are not permanently installed, with the following amendments:

- 1) Since the as-proposed NSPS OOOOb and EG OOOOc require phase out of this equipment and numerous operators have been reducing these equipment counts voluntarily, it is not possible to

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monitor the same number of controllers each year since equipment counts will be simultaneously declining. Instead, **EPA should require the annual inspections to cover at least 20% of the population of pneumatic controllers at a facility** that have not already been inspected pursuant to Subpart W within the previous 4 years, provided that each device remaining in service at the end of the first five years has received at least one inspection over the five-year period.

- 2) Additionally, EPA should allow operators to **directly measure a representative sample of pneumatic devices in lieu of the entire population**. This approach ensures accuracy of reported emissions but recognizes the vast geographic dispersion of upstream sites. Additionally, API performed a study on the count of pneumatics at upstream sites and provided that in comments regarding the supplemental OOOOb rulemaking.¹⁴ The time required to drive to each site would be unnecessary when a smaller, representative sample accurately reflects the emissions from these devices. Lastly, this approach is incorporated in several voluntary programs (e.g., OGMP 2.0), retains the accuracy of reported emissions, considers the large geographic dispersion of upstream sites, is consistent with the approach proposed for equipment leaks, improves accuracy over generic emission factor-based estimates, and is more cost effective. The representative emission factor approach would require measurement of a representative sample of pneumatic devices to determine a “facility” specific emission factor.

3.1.3 Method 3 – Suggested Amendments to Improve Intermittent-Bleed Device Monitoring

The Industry Trades also generally support EPA’s Calculation Method 3; however, **EPA should amend Calculation Method 3 in three important ways:**

- 1) **EPA should allow the use of a whole gas emission factor as an option for intermittent-bleed devices**, for the reasons stated in Section 3.1.1.
- 2) **EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers**, including a broader suite of field data to improve accuracy. Emission factors should incorporate data from additional relevant studies,^{15,16,17} one of which is the API Study “Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States,” where the data and results have been appended to this letter in Annex A. We encourage EPA to utilize the data from this API study, since the API dataset adds 263 additional measurements of intermittent bleed controllers and cover a wide cross section of the industry sectors (production and gathering and boosting sites)¹⁸

¹⁴ <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428>.

¹⁵ Raw data and linked analyses/reports available at <http://dept.ceer.utexas.edu/methane/study/>. Accessed September 24, 2023.

¹⁶ David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld. *Environmental Science & Technology* 2015 49 (1), 633-640. DOI: 10.1021/es5040156

¹⁷ API Study “Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States” attached in Annex A and data provided by attachment as an Excel file within this docket.

¹⁸ Note that EPA’s comment in the TSD regarding being near or below the OGI threshold for properly functioning controllers using the API field study’s emission factor would be resolved by combining the Zimmerle, API, and other relevant datasets to derive properly functioning and malfunctioning emission factors as shown below in Revised Eq. W-1C (the proposed properly functioning emission factor of 0.9 scf/hr/device is equivalent to ~17 g/hr, which is

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while the Zimmerle *et al* study only evaluated sites with compression; thus, the resulting bifurcated emission factors would be more accurate and representative. Specifically, **the Industry Trades recommend revision of Eq. W-1C:**¹⁹

$$E_i = GHG_i \times \left[\sum_{z=1}^x \{20.0 \times T_{mal,z} + 0.9 \times (T_{t,z} - T_{mal,z})\} + (0.9 \times Count \times T_{avg}) \right] \text{ (Rev. Eq. W - 1C)}$$

Where:

20.0 = Whole gas emission factor for properly functioning intermittent-bleed controllers, scf/hr.

0.9 = Whole gas emission factor for malfunctioning intermittent-bleed controllers, scf/hr.

- 3) **EPA should allow for the optional estimation of properly operating pneumatic controllers based on equipment specific engineering calculations**, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency,²⁰ **or the development of a facility specific properly operating emission factor through direct measurement** of a representative sample of devices across a facility.

$$E_i = GHG_i \times \left[\sum_{z=1}^x \{16.1 \times T_{mal,z} + EF_z \times (T_{t,z} - T_{mal,z})\} + \sum_{y=1}^y \{EF_y \times T_{t,y}\} \right]$$

Where:

z = Count of intermittent bleed pneumatic devices that malfunctioned during the reporting period,

y = Count of intermittent pneumatic devices that properly operated over the entire duration of the reporting period, and

EF = Properly operating emission factor for the specific device or facility.

3.1.4 Intermittent-Bleed Device Survey Improvements

The duration of an intermittent bleed device malfunction should be determined by repair date or other detection approaches, in addition to traditional survey repair verifications.

Operators will have a clear indicator that a malfunctioning device has been returned to properly operating condition based upon the repair date or other detection approaches. EPA should allow for such information to be used for the time input into the malfunctioning controller emission estimation equation, which aligns with EPA's efforts to increase the quality / accuracy of the reported data. For

above the OGI detection limit). EPA also speculates in the TSD that the API field study included many zero emitting measurements due to the short measurement duration. However, as discussed in the attached paper (see Annex A, pp. 4), the measured emission data points that were below half the effective resolution were conservatively assumed to be half the effective resolution for the minimum instantaneous emission rate in all the analyses. Further, the Allen *et al* 2014 paper conducted a sensitivity analysis which showed that actuations that were just missed by the measurement timeline at 15 minutes had a very small effect on the overall population emission factor estimate.

¹⁹ See Annex F Analysis to support amendment to Calculation 3 for Intermittent Bleed Devices.

²⁰ <https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf>.

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example, while conducting AVO inspections, operators can detect that an intermittent device is continuously venting by feeling the gas exit port.

The Industry Trades also support EPA's proposal to retain the option for an operator to apply engineering estimates to determine the time in which the device was in service, in lieu of the default 8760 hours.

Intermittent bleed device surveys should include additional flexibility by allowing audio, visual, and olfactory (AVO) inspections.

Operators should be able to take credit for any surveys, provided those surveys satisfy the intent of the rule. Based on the proposed rule for NSPS OOOOb, facilities subject to NSPS OOOOb monitoring would be required to use non-emitting pneumatic devices. Some facilities that are not subject to NSPS OOOOb may conduct LDAR for state, federal, or voluntary programs and may wish to screen pneumatic controllers while on-site and use that empirical observation of properly functioning or malfunctioning for GHGRP reporting.

While many of these regulatory programs would meet the technology options provided in 98.234(a) for use in monitoring properly functioning pneumatic devices, additional flexibility should be incorporated by allowing the use of AVO. AVO is appropriate because AVO inspections can be used to detect that an intermittent device is continuously venting through feeling the gas exit port, as previously stated.

3.1.5 EPA Has Underestimated the Cost of Direct Measurement for Pneumatic Devices

Oil and gas companies do not currently own or have training to conduct direct measurement of pneumatic devices. EPA included no additional cost for purchasing the high flow sampling equipment, staff or training on the equipment. With the large number of operators having to acquire this data at the same time, new equipment must be first manufactured and then purchased by these operators to do this work concurrently. EPA added no additional labor impact; it will require significantly more staff to conduct the measurements. The company will need to hire staff, as additional staff will be needed to conduct these measurements that require 15 minutes per measurement minimum over a range of device counts per facility depending on whether it is a gas or oil well, number of wells, and the equipment required for production. It will likely not be possible to cover 5-10 sites per day, considering repairs will likely be performed at the same time and many sites and pneumatic devices will be spread out over long distances. Furthermore, operators will need to be trained to use high flow samplers as this equipment is currently not used in the oil and gas industry. None of these additional costs have been addressed in the Regulatory Impact Analysis. EPA claimed all this could be done with only an additional \$600,714 in cost which would not be sufficient to cover the cost for a medium sized operator.

3.2 Acid Gas Removal and Nitrogen Removal Units

3.2.1 Proposed Methods for Methane Emissions

The proposed mass balance approach for quantifying emissions will not lead to accurate reporting for methane emissions, and sour gas sampling poses a significant safety concern.

EPA proposes to report methane along with CO₂ from Acid Gas Removal Units (AGRUs) and Nitrogen Removal Units (NRUs). The Industry Trades believe that the proposed methodology in Equation W-4C (a mass balance approach) will not lead to accurate reporting for methane emissions. Since the solubility of methane in amine is very low, the difference in methane concentration in the inlet and outlet processed gas stream will be negligible. Therefore, the ability to discern a difference in inlet versus outlet methane

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composition will make it difficult (if not impossible) to accurately determine methane emissions using a mass balance approach. Further, sampling the high-pressure acid gas stream at the inlet of the AGRU contactor poses a significant safety concern (see next comment). For these reasons, the Industry Trades recommend removing this methodology for methane emissions reporting.

EPA is proposing a requirement to perform direct sampling of gas streams into these units at least annually. The Industry Trades remind EPA that these streams can also contain dangerous levels of hydrogen sulfide (H₂S), and any work near or around these units that is not necessary for the optimal function of the equipment should be limited to protect the personnel responsible for performing these tasks. The Industry Trades recommend removing the prescriptive sampling requirements for these streams and allow reporters to use representative samples or direct site-specific samples if deemed to be appropriate.

For the simulation method (Method 4), the Industry Trades recommend that EPA clarify that representative measurements can be one time, annual or a more frequent measurement as deemed appropriate for the facility's operation.

3.2.2 Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

EPA proposes that those operators sending gas from an AGRU or NRU to a control device also report associated details regarding the combustion device (flare ID, gas flow rate, etc.). Requiring this information to be reported on this tab of the Subpart W reporting form could cause duplicative reporting with sources on other tabs (e.g., flares), and is ultimately not relevant to reporting by itself. The Industry Trades recommend removing this requirement. Reporting this level of detail is also inconsistent with EPA's 2022 proposed revisions, which greatly streamlined the reporting requirements for flares.

EPA is proposing to include solvent type in data reporting; the Industry Trades does not believe this information to be beneficial or helpful in validating the reported information, and EPA did not address why this element is to be reported in the TSD. The Industry Trades recommend that the EPA remove this unnecessary reporting requirement.

Finally, the Industry Trades request clarity from EPA around reporting activities such as acid gas injection through Subparts W, PP and UU. The proposed requirement to report CO₂ sent offsite under Subpart PP is duplicative of CO₂ supplier reporting. Regarding the WEC, it will be absolutely critical that industry has a clear understanding of exactly how emissions are to be accounted for between these subparts without over-reporting, double counting, or allowing some operators to not report under these subparts at all (creating an economic disadvantage as it is unclear how some activities which result in producing CO₂ are to be accounted for in the various rules).

3.3 Dehydrators

3.3.1 Desiccant Dehydrators

Reporting requirements for desiccant dehydrators should be streamlined for a source type that is not a significant contributor to GHG emissions.

In the late-2022 proposed changes, EPA appeared to be moving away from requiring detailed information reported for desiccant dehydrators; however, in the current proposal (August 1st, 2023), EPA is requiring more reporting details. Emissions from desiccant dehydrators are periodic and can be very infrequent in nature. The Industry Trades support reducing the overall reporting requirements on these units as they are not significant contributors to annual GHG emissions.

Molecular sieve dehydrator emissions are expected to be extremely infrequent (i.e., once every 5-10 years), and should be categorized as blowdown emissions.

EPA is also proposing to add molecular sieve units to the desiccant dehydrator category. Molecular sieves are closed systems with no emissions to the atmosphere, except when the desiccant must be changed which is infrequent; typically, only once every 5-10 years. Furthermore, emissions from opening a molecular sieve dehydrator would be an activity considered by most operators to be a blowdown event – and should be accounted for under the blowdown category rather than under dehydrators. Categorizing molecular sieves under the desiccant dehydrator category not only raises confusion but could potentially result in double counting of the blowdown emissions.

3.3.2 Proposed Measurement Data

The proposed measurement requirements are burdensome and will not increase the accuracy of the emissions estimates; therefore, engineering estimates for parameters should be allowed.

EPA is proposing to require direct measurement of some parameters for large dehydrators. Specifically, EPA is proposing to require direct measurement of the feed natural gas flow rate, feed natural gas water content, and wet natural gas temperature and pressure at the absorber inlet. The Industry Trades do not believe that direct measurement of these parameters is appropriate nor that it would result in more accurately reported emissions. Sampling the feed natural gas water content, gas temperature and pressure will provide an instantaneous snapshot view of the operational conditions of a unit that operates year-round, and in potentially varying operating conditions, during which these parameters may shift.

In some instances, facilities are not equipped with a meter upstream of the dehydration unit; instead, the gas is measured at the outlet of the facility. As a result, collecting direct measurement of feed natural gas flowrate will require extensive modifications without increasing the quality of the reported data. Dehydrator emissions are not directly proportional to natural gas throughput; in other words, the inlet gas rate to the dehydrator alone does not correlate with dehydrator emissions. Instead, glycol recirculation pump rate, configuration (e.g., flash tank separator, stripping gas) and operating pressures do impact emissions, and are known by operations in order to maintain optimum operating conditions. Requiring operators to install, calibrate and maintain meters at the inlet to the dehydrators would be costly while not addressing the accuracy of the elements that do meaningfully impact actual emissions. Therefore, the Industry Trades request that engineering estimates of the parameters used in the

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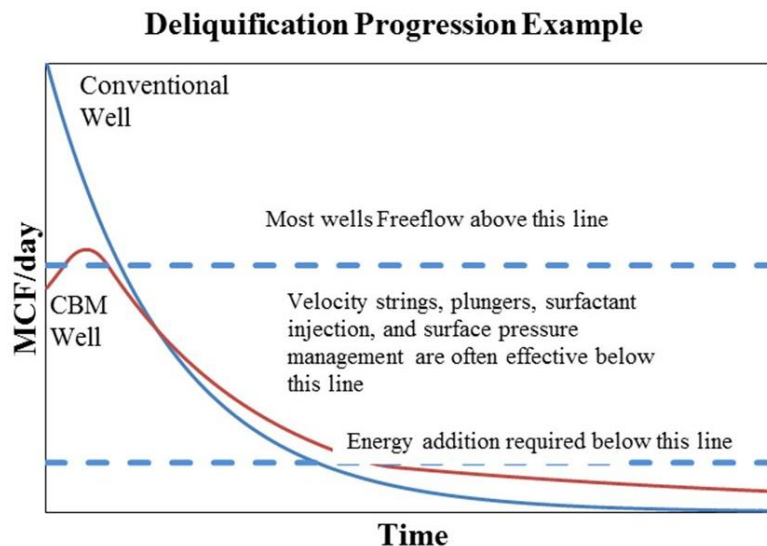
simulation software continue to be included as an option, especially considering the parameters represent annual averages.

3.4 Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

The proposed rule language that requires Calculation Method 1 every three years is unnecessary and burdensome and will not lead to more accurate reporting. EPA states in the preamble that this requirement will ‘ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading event.’ EPA must justify this additional burden and how potential differences between method results will be treated, as repeated validation of the methods will not lead to more accurate reporting. Further, EPA did not consider the Allen *et al* 2015 study that directly measured emissions from liquids unloading.²¹

Which wells will require and how often they require liquids unloading venting is not predictable or consistent. Liquids unloading or deliquification is the process of removing liquids build-up in a gas well. Not all deliquification techniques result in venting. Most wells in the US do not vent to the atmosphere. Managing well bore liquids build-up in gas wells is required to maintain production, avoid early abandonment of the wells, and maximize resource recovery. Liquids build up in the well when the velocity of the production string is not sufficient to push the liquids up the well bore. The deliquification approaches change as a well moves through its lifecycle, as shown in the figure below. Manually opening a well to atmosphere to reduce the back pressure on the liquids column results in most of the liquids unloading venting. When this is needed is variable and does not necessarily occur every 3 years.



²¹ <https://pubs.acs.org/doi/10.1021/es504016r>.

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Adding a flow meter will put back pressure on the well, restricting flow and preventing the well from unloading or making it more difficult. The purpose of liquids unloading is to relieve the back pressure on the well so that the well is able to push liquids, and a flow meter would prevent this from occurring. Anecdotal evidence from one operator that currently unloads gas wells in Colorado has trialed measurement on liquids unloading on twelve wells indicating this. The operator found results similar to the current GHGRP calculations. Additionally, the operator found that to use a meter, the gas must be routed through a knockout or other vessel that may have small piping between it and the meter. The constriction made the unloads take longer and reduced the effectiveness of the unloads. Of the twelve trial measurements, not a single well successfully unloaded itself.

The volume of gas, and associated GHG emissions, is relatively low and therefore does not warrant the additional expense and effort of measurement. In fact, the total emissions reported in 2021 for all operators was a very small percentage of overall methane emissions from onshore production.

Measuring the small volume will be extremely challenging and likely require a costly ultrasonic meter (please see the flow meter challenges discussed in more detail in Section 3.8.13.8.1 of the comments). The measurements will be challenging to obtain, as they are short duration and turbulent flow; therefore, the low flow is unlikely to be measured by a flow meter.

The rule does not account for all the added costs of a flow meter that will likely not be capable of measuring the small volume of the gas. These costs include:

- The flow meter(s)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofit the line to add a flow meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the flow meter
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

Additionally, EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. NSPS OOOOb does not prescribe these flow meter requirements as necessary to achieve the zero-emission limit for liquids unloading, or for the recordkeeping/reporting requirements for these events, so it is unclear why this would be required under Subpart W.

Furthermore, a meter could be installed on a well that had liquids unloading venting in a previous year and never does again, or not be installed on a well that suddenly requires liquids unloading venting.

Industry should be allowed to continue to use the liquid unloading engineering estimates or other engineering process knowledge to estimate the duration and volume of emissions as measurement will not result in more accurate estimates.

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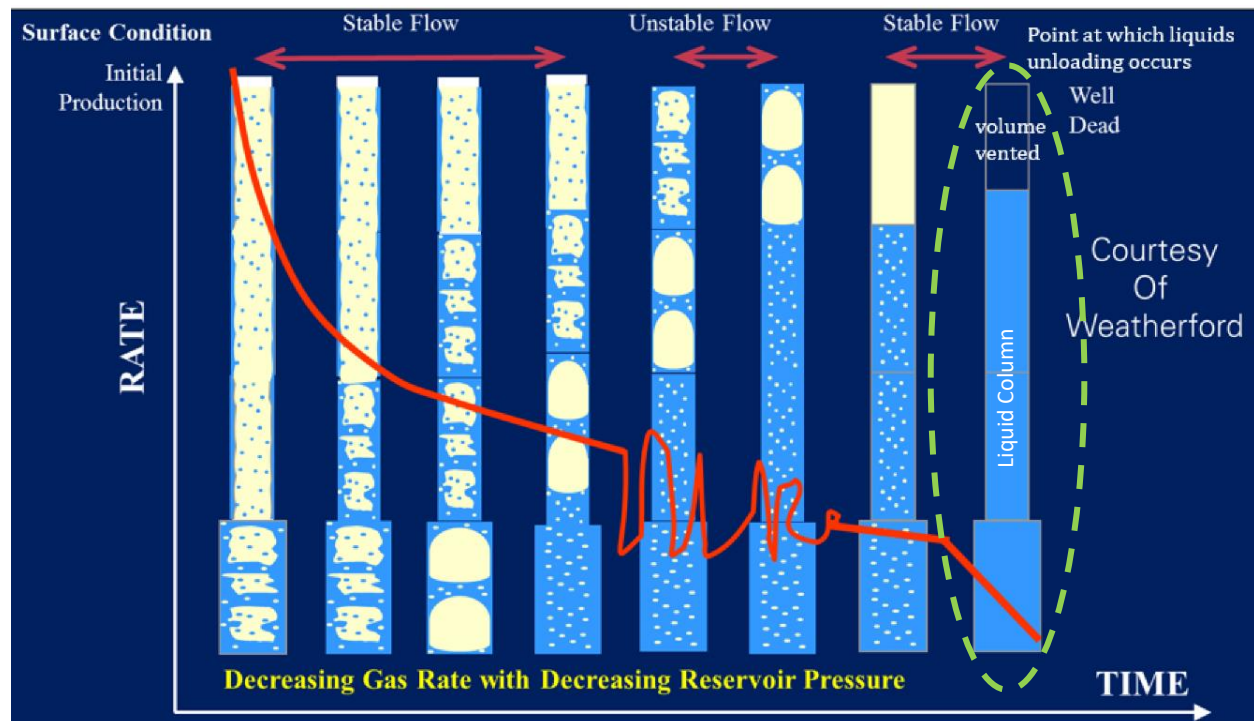
Additional suggested revisions will improve the clarity of the requirements for reporters.

EPA should clarify that liquids unloading only applies to gas wells as was done in NSPS OOOOb. Oil wells typically require artificial lift to produce the liquids and do not vent gas.

The Industry Trades support proposed revisions to add reporting requirements for liquids unloading events which vent directly to atmosphere or are routed to a control device, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, EPA should clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device. These additions will improve clarity for reporters and provide greater context for the reported emissions for EPA.

Additionally, EPA should consider revising the definition of CDp in Equation W-8 to Idp (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. It is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. EPA should also clarify that the depth is based only on the vertical depth for horizontal wells.

Furthermore, the volume should be able to account for the fluid column depth. EPA should allow companies to determine the depth to the top of the fluid and exclude the remaining volume from the venting volume estimate. The reason for liquids unloading is to remove the liquid column from the well. The volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas, as shown by the 'volume vented' in the following diagram.



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3.5 Blowdowns

Streamline blowdown reporting to reduce the burden without affecting accuracy.

EPA is proposing to require site-level details regarding blowdowns. The Industry Trades recommend streamlining this source category by allowing reporters to aggregate events by type at each facility. Aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. For example, EPA should allow blowdown emissions to be reported by site, but aggregated by activity (i.e., all blowdown types would be reported in aggregate rather than line-by-line for each blowdown event).

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting a site could be challenging. The Industry Trades recommend allowing these types of blowdown events to be aggregated by county (without segment ID), which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA).

As discussed in the ‘Other Large Release Events’ comments, there is a significant probability of double counting between blowdowns and ‘Other Large Release Events’ due to the low emission rate threshold proposed for the ‘other large release events’ source.

The Industry Trades are also concerned that, due to the low hourly emission rate threshold specified by EPA for the “Other Large Release Events” category, these events could be inadvertently counted in both this blowdown category as well as “Other Large Release Events” - resulting in significant double counting. EPA should clarify that any emission event that triggers the “Other Large Release Events” threshold but belongs under a reportable emissions source category (e.g., blowdowns) should be reported within its associated source category, not under “Other Large Release Events.” The Industry Trades have elaborated on this point in the “Other Large Release Events” section of this letter.

3.6 Storage Tanks

3.6.1 Produced Water Tanks

Requiring estimation of emissions from produced water tanks is burdensome and unnecessary due to the low expected emissions of methane based on solubility limits.

Methane emissions from produced water tanks are expected to be low due to solubility limitations of methane in water. A study conducted by Idaho State University²² to quantify the solubility of methane in produced water found that the solubility of methane was in a range between 1 and 12 scf/barrel at pressures ranging from around 100 to 2,000 psi and temperatures ranging from 200 to 300°F. While the study did not publish results for lower temperature ranges, the authors state that the solubility decreases with decreasing temperature and/or pressure. The solubility of methane in produced water is also expected to be lower in the presence of other hydrocarbon gases, such as ethane, per the study authors. The Idaho State University methane solubility study results are aligned with the produced water emission factors published in the 2021 API Compendium (Table 6-26): the Idaho State University study value at around 1000 psi, 200°F and 13 % salinity (4.2 scf/bbl.) equates to around 0.08 tonne CH₄/1,000 bbl which compares to 0.0536 tonne CH₄/1,000 bbl (at 1000 psi, 10% salinity) from Table 6-26 of the API Compendium. Since the methane emissions from a produced water tank would be lower than the

²² Blount, C. *et al*, *Solubility of Methane in Water Under Natural Conditions*, Idaho State University Department of Geology, June 1982, <https://www.osti.gov/servlets/purl/5281520>.

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solubility limit (i.e., emissions are based on the partial pressure of methane in the tank headspace, which is lowered when other hydrocarbons are present), the Idaho State University study corroborates the API Compendium emission factors for produced water tanks.

If EPA opts to keep produced water tanks in the GHGRP, the Industry Trades recommend allowing operators to assume that water tanks contain 1% of the oil content. Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance²³ describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank. The Industry Trades recommend that EPA allow operators to assume that 1% of the oil content is in the produced water tanks which is a conservative estimation given that the guidance is intended to capture VOC emissions, and it is unlikely (as described above) that significant methane remains in the produced water.

The Industry Trades note that EPA provides a stuck dump valve emission factor for water tanks if method 1 or 2 is used, but no factor is provided for tanks using method 3.

3.6.2 Thief Hatches

EPA should allow improperly seated thief hatches to be treated as an “other” component under equipment leaks. The proposed capture efficiency of zero percent for storage tanks with an improperly seated thief hatch is inaccurate and would significantly overestimate emissions.

EPA has proposed a 100 percent reduction in VRU capture efficiency and flare destruction efficiency for both hydrocarbon and produced water storage tanks with open and improperly seated thief hatches. This proposed reduction in capture efficiency is inaccurate and would significantly overestimate methane emissions. The Industry Trades propose a bifurcated approach to reporting emissions from thief hatches where improperly seated thief hatches would be treated as a fugitive emission reported under equipment leaks, and open thief hatches would result in a zero percent capture efficiency for control devices.

Thief hatches are safety devices that relieve positive and negative pressure in atmospheric storage tanks to prevent structural damage. Thief hatches accomplish this by using weights or springs that allow the thief hatch valve to open at given pressure and vacuum settings. The thief hatch valve then reseats after the tank pressure or vacuum has dissipated. Thief hatch valves are designed to seat with minimal leakage under their pressure setting. For example, Enardo 660s, a common thief hatch in the upstream oil and gas industry, conforms to API 2000 Venting Atmospheric and Low-Pressure Storage Tanks Standard to not leak more than 5 SCFH at 75-90% of the thief hatch valve’s pressure setpoint. Many of Enardo’s valves can achieve smaller leak rates at 90% of the pressure setpoint. LaMot’s L12 series thief hatches, another common type found at upstream oil and gas facilities, will not leak more than 1 SCFH at 90% of the pressure setpoint. These leak rates are a fraction of the gas produced in tanks. For example, the reduction in capture efficiency ranges from 0.5% to 2.5% given these leak rates for tanks with a relatively small throughput of 100 bbl./day and average GOR of 48 scfs/bbl given the above leak rates. Improperly seated thief hatches are technically closed but leak around the seat due to either grime on the valve gasket or an inadequate seal, similar to valves that leak into open-ended lines. Improperly seated thief hatches do not result in a zero percent capture efficiency because they are still able to

²³ [produced-water.pdf \(texas.gov\)](#).

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maintain positive pressure on the tanks, allowing gases to be routed to the control device. The leakage from an improperly seated thief hatch is significantly lower than from a partially open thief hatch.

EPA's proposal to assume zero percent capture efficiency from improperly seated thief hatches that are leaking as opposed to venting gas will grossly overstate methane emissions. Instead, the Industry Trades propose that improperly seated thief hatches be considered and reported as a fugitive emissions component (under the "other" fugitive component category).

A zero percent capture efficiency as proposed by EPA would be used for thief hatches that are observed above their setpoint using pressure transmitters and confirmed open or found open during inspections. The Industry Trades believe that this bifurcated approach of accounting for improperly seated thief hatches as equipment leaks, and assuming open thief hatches result in a zero percent capture efficiency would be a more accurate representation of emissions from thief hatches.

EPA should allow engineering estimates of the open thief hatch volumetric flow for tank batteries with a common vent line.

For many tank batteries, vent lines for multiple tanks are combined in a common vent line header that is routed to a control device. If one thief hatch is found open, the entire tank battery should not be assumed to have open thief hatches with a resultant zero percent capture efficiency. The Industry Trades suggest that EPA allow for use of engineering estimates, e.g., modeled volumes, in this case to report the emissions from the tank battery's open thief hatch.

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

EPA proposes thief hatch sensors or visual inspections as the monitoring options for detecting open thief hatches on controlled storage tanks. The Industry Trades recommend that EPA allow Tank Emission Monitoring Systems (TEMS) or other parametric monitoring in addition to thief hatch sensors. For example, many companies utilize a pressure transmitter or similar device to determine if a thief hatch is venting as they are more accurate.

Similarly, EPA should expand the visual inspections to allow other monitoring techniques (audio and olfactory in addition to visual, OGI, and alternative screening technology) due to potential safety issues with a strictly visual inspection of thief hatches. Since thief hatches are located on the top of the tanks, a visual inspection may require personnel to climb to the top of the tanks with potential vapor exposure (e.g., H₂S). Therefore, more remote monitoring techniques should be allowed to monitor for open thief hatches on controlled tanks.

Thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. As such, EPA should allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (e.g., TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

EPA is proposing that an open thief hatch without a thief hatch sensor is to be considered open since the last required inspection, which is proposed at least annually or more frequently if subject to AVO surveys under NSPS OOOOb or EG OOOOc. The Industry Trades recommend that EPA allow an operator to

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assume the thief hatch has been open since the last credible inspection (e.g., routine operator inspection) and not solely based on the last required thief hatch inspection. Proposed NSPS OOOOb and EG OOOOc (and earlier versions of the NSPS) do not require thief hatch sensors but instead require routine inspections of closed vent systems and covers for applicable storage vessels in addition to routine site surveys of fugitive emissions components. These inspections and additional monitoring would offer more frequent opportunities for operators to identify open thief hatches on a routine basis.

Emissions from an open thief hatch should be reported for the year in which it was discovered.

EPA is also seeking comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. The Industry Trades suggest that the reporting for an open thief hatch be limited to the calendar year in which the open thief hatch is discovered. If the thief hatch is open over a period that started prior to the start of the reporting year, then the total duration should be reported in the year in which it was discovered to avoid re-submittal of prior year reports. To expand on this point, the Industry Trades propose that any episodic GHG emissions be reported solely in the reporting year in which it was discovered.

3.6.3 Atmospheric Storage Tank Exclusions

The Industry Trades recommend that emergency use storage tanks and process tanks not be subject to reporting.

The Industry Trades also recommend that EPA specify that some tanks are not subject to reporting under this program. Some facilities contain tanks which are used only rarely for off spec oil and should be excluded from the definition of storage vessel. These process vessels are rated significantly higher than atmospheric and do not have similar venting risks as atmospheric storage tanks. The expected GHG emissions from these emergency use storage tanks would be minimal. At the state level, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.^{24,25}

Likewise, process tanks like those that recirculate liquids for processing should also be excluded. Storage tank regulations, including proposed NSPS OOOOb and EG OOOOc, have historically excluded process vessels or tanks. In short, any tank which is not expressly used as a primary storage vessel for hydrocarbon liquids and produced water (if included as proposed) in the normal operation of a production or gathering and boosting facility should be excluded. Therefore, the Industry Trades offer the following redline of the proposed definition of atmospheric pressure storage tank:

²⁴ CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

²⁵ The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

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Atmospheric pressure storage tank means a vessel ~~(excluding sumps)~~ operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof. For the purposes of this subpart, the following are not considered atmospheric pressure storage tanks:

- Sumps;
- Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and
- Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.

3.6.4 Gas-liquid Separator Liquid Dump Valves

The start date for a stuck separator dump valve should be based on best available monitoring data.

Like the above comment on open thief hatch monitoring, EPA should allow the start date for a stuck gas-liquid separator liquid dump valve to be based on the best monitoring data available (TEMS, other parametric monitoring, alternative screening technology, routine operator inspections, etc.) rather than solely the date of the last required annual visual dump valve inspection. This flexibility will allow operators to calculate storage tank emissions more accurately.

3.6.5 Addressing EPA's Request for Comments

Industry Trades recommend adding GOR analyses as an allowable calculation methodology.

EPA is seeking comments on whether adding a laboratory measurement of the GOR from a pressurized liquid sample is an appropriate calculation methodology for atmospheric storage tanks. The Industry Trades are supportive of adding this GOR method to calculate emissions from storage tanks and emphasize that these samples do not need to be taken on a site-by-site basis to be representative.

3.7 Associated Gas Venting and Flaring

EPA is proposing to require reporting of associated gas venting and flaring on a site-by-site basis. The Industry Trades recommend that EPA keep emissions and associated data rolled up to the basin-level (or county-level, as required by other regulatory programs, such as PHMSA).

EPA is seeking comment on whether to continue to require reporting of GOR, produced oil volume, gas to sales volume, etc. The Industry Trades are in support of no longer requiring these reporting elements, unless required by the WEC. In general, the Industry Trades support efforts to streamline the data reporting process, particularly when the reported elements are not used to calculate emissions.

3.8 Flares

It is critical to the Industry Trades that the GHGRP does not directly include monitoring, measuring and sampling requirements for flares in order to avoid conflicting or duplicative requirements. Instead, the GHGRP should refer to data available through other applicable federal air quality regulatory programs. The Industry Trades request that EPA should ensure consistency across programs. This will help ensure

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that the requirements in the GHGRP are fully harmonized with any potential requirements under other federal air quality programs.

The Industry Trades support more accurate approaches for destruction efficiency for estimating flare emissions; however, the **tiers as proposed should be amended** (specific comments below). Further, while it is sensible to allow for the use of available empirical data and appropriate to define multiple estimation methods based on different types of available information, **monitoring requirements that are repeated in Subpart W rather than referencing the applicable regulation, especially those that exceed NPS 0000b and EG 0000c requirements, which are defined in those rules, should not be included in Subpart W**. Further, flare estimating methods should be appropriate to the equipment and designs deployed within the segment (e.g., small, mostly unassisted, distributed flares) rather than arbitrarily under a rubric designed for a specific compliance assurance matter from a very different set of facilities and designs (refining and chemical manufacturing). Finally, flared emissions should be reported at the facility level rather than at the individual well pad or site, and especially not with attribution to the flare gas source.

With the Industry Trade's recommendations, the Industry Trades generally support EPA's focus on pilot flame monitoring as unlit flares can be large sources of methane emissions from flares. However, the proposed rule's requirements to continuously measure or monitor flow volumes, as well as use continuous gas analyzers or pull quarterly samples for gas compositions would result in little benefit to accuracy while posing significant costs and safety risks. Further, the Industry Trades disagree with EPA's proposed three-tier destruction efficiency (see Comment under Section 3.8.4 below).

3.8.1 Flow Measurement

3.8.1.1 EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

The Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices. The proposed flare metering requirements are infeasible, burdensome and may lead to inaccuracies for most flares in production and gathering and boosting operations. Furthermore, EPA did not address the need to measure flare flow in the proposed rule's TSD. Likewise, the proposed parametric monitoring does not provide a more accurate or cost-effective alternative to metering. **EPA should retain the current Subpart W language stating that, "...If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."**²⁶

Proposed Flare Measurement Methods are Inaccurate and Infeasible for Low Pressure Flares

The proposed flare flow measurement methods are inaccurate, as well as infeasible, for low pressure flares in production and gathering and boosting operations.

The primary streams that are routed to flare at typical oil and gas facilities include:

²⁶ Current § 98.233(n)(1)

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- Low-flow pilot, purge, sweep, and/or auxiliary gas used to ensure flares are lit, operating safely, and have optimal destruction efficiencies;
- Low- pressure gas that is intermittent and turbulent from tank flashing, working, and breathing losses;
- Mid- pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales that has intermittent and turbulent flow; and
- High pressure separator gas flaring in areas with stranded gas pipeline take-away loss that has intermittent flow and is decreasing across the country.

Most meters are unable to accurately measure the flow of low-volume, low-pressure, intermittent, and turbulent streams.

In addition to the concerns surrounding the metering of each individual stream, the Industry Trades are concerned with EPA's application of flow meters or parametric monitoring across every upstream application. EPA's requirement to use continuous flow measurement devices or parametric monitoring for low-pressure flares and purge/sweep/auxiliary gas streams is technically infeasible. Meters require steady pressure and flow to accurately measure flow rates. Most meters are unable to accurately measure low pressure and flow conditions found in purge/sweep/auxiliary gas and storage tank streams, or variable flows affecting several streams, such as tanks due to production slugs or when separators dump fluids, sporadic flaring of associated natural gas, and high-pressure equipment blowdowns. Furthermore, the flare volumes rapidly decline from the initial production of the well and become more sporadic. Metering the scenarios described is challenging, and industry needs a flexible array of options to ensure proper combustion and accurate reporting. The incorrect application of meters or parametric monitoring devices can lead to inaccurate flare volumes relative to using process simulations, engineering estimates, and indirect measurement allowed under the current rule. **The Industry Trades recommend the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.** The industry utilizes reliable process simulation and engineering calculations which are often more accurate than metering low pressure, low flow, and highly variable streams within the upstream oil and gas industry. The Agency and industry rely on process simulation and engineering calculations in permitting, designing and maintaining facilities for safety and environmental reasons, and have made great strides in the accuracy of these approaches in recent decades. Additionally, the GHGRP allows process simulation to estimate composition and volume of gas for emissions (e.g., tank flash gas, dehydrators, etc.) that are not going to flare so the same methods should be allowed for gas streams that do go to flare. As such, it does not make sense to expend significant capital and operational resources to install continuous monitoring when engineering estimates are more reliable and allowed for uncontrolled sources (e.g., storage tank vents and dehydrators). Interestingly, EPA couples burdensome, although potentially less accurate, measurement technology for flow with default destruction efficiencies, without allowance for measurement or performance test data; this would negate any possible improvements in flare emissions accuracy.

In Colorado, the Air Pollution Control Division (APCD) recognized that flow meters have low accuracy at low vapor volumes by first approving a variance in 2022 to their flow meter requirements and more recently amending their Regulation 7 rule language in 2023 to include pressure actuators as an alternative to flow meters. Pressure actuators are an example of a solution implemented to ensure

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combustion. For reporting purposes, engineering estimates and simulation software based on site specific information (e.g., GOR and liquid throughput) are more accurate to generate emissions reporting information for flares in the production and gathering and boosting operations. It is important that the EPA understands that proper combustion and accurate reporting go hand in hand and should be viewed holistically so that operators are efficiently managing both concerns.

Meters available in the market and widely used in upstream oil and gas applications include differential pressure meters (e.g., orifice plate and v-cones), thermal mass meters, and ultrasonic meters. Differential pressure meters work by measuring the upstream and downstream pressure from a plate or cone with an orifice that allows gas to pass through. The amount of differential pressure can be increased or decreased for any given flow rate by selecting plates or cones with smaller and larger orifices. The flow of the gas passing through the meter can be inferred by the differential pressure between both points. The ratio of minimum and maximum capacities of meters, known as the turndown ratio, typically should not exceed 4:1 for differential pressure. This causes three primary considerations for differential pressure meters: first, they are inaccurate in low-pressure conditions; second, they are unable to accurately measure variable flow rates given their relatively tight turndown ratio (Zhang & Wang, 2021);²⁷ and lastly, they are sensitive to liquid and debris clogging the orifice causing an artificial increase in differential pressure and inaccurate high flow volume measurements. The relationship between low-pressure conditions, tight turndowns, and sensitivity to operating conditions is exacerbated by the fact that smaller orifices must be selected for lower pressures, causing even tighter turndown ratios that are more inaccurate with variable rates, and increasing the likelihood of clogging. Orifices can also become blown out by sudden increases in flow volume or debris, which causes a decrease in differential pressure and inaccurate low flow volume measurements. This makes differential pressure meters technically infeasible to measure purge, sweep and auxiliary gas lines that operate at low pressures, tank vent lines that operate at near atmospheric conditions, and high-pressure gas lines that are more variable than the turndown ratio of these meters.

Thermal mass meters operate on the principle of thermal dispersion, which states that the amount of heat absorbed by a fluid is proportional to its mass flow. These meters work by either comparing heat loss between two elements, or by measuring the amount of energy that must be expended to heat gas to a certain setpoint. Similar to differential pressure meters, thermal mass meters cannot accurately detect lower flow rates due to the unmeasurably small differences in temperature between the two elements or energy required to heat gas for low flow volumes. As noted in Kerr-McGee's letter to Colorado Department of Public Health & Environment Air Pollution Control Division (APCD) dated April 12th, 2022²⁸, the turndown ratio of thermal mass meters is typically 33:1, which means the meter is unreliable until 3% of the meter's maximum flowrate of 1,180 thousand standard cubic feet per day (MCFD) is achieved. Additional information regarding this comment can be found in Annex C of this letter. This also makes thermal mass meters technically infeasible to measure pilot/purge gas lines and tank vent lines as these streams do not meet the minimum flowrates required for thermal mass meters due to their low rates and declining production over time. In addition to issues with low flow rates, thermal mass meters are highly susceptible to entrained mist, liquid, or particles that can affect the

²⁷ Zhang, Y and Wang, J. *Review of metering and gas measurements in high-volume shale gas wells*, *Journal of Petroleum Exploration and Production Technology*, 12:1561-1594, December 2021, <https://doi.org/10.1007/s13202-021-01395-9>.

²⁸ APCD-PHS-EX-035.

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thermal properties of the gas being measured (API, 2021).²⁹ For example, the specific heat capacity of propane increases from 1.67 kJ/Kg-K in the gaseous phase to 2.4 kJ/Kg-K in the liquid phase. Thermal mass meters can measure dry gas in steady flow conditions above their minimum capacity, which makes them suitable for select flare scenarios depending on facility design and process. However, they do not have the level of accuracy required to form any basis for the methane fee.

Ultrasonic meters operate on the principle of doppler shift by measuring the time it takes for sound to travel from an ultrasonic signal transmitter to a receiver upstream and downstream of gas flow. Generally, ultrasonic meters do not work well in low flow conditions because of the unmeasurably small doppler shift that occurs at lower velocities. Thus, they are technically infeasible to accurately measure low pressure pilot/purge gas and storage tank streams. They are also sensitive to mist, liquids, or particulates that may block the receiver from receiving the ultrasonic signal, but not as much as differential pressure or thermal mass meters. They are also sensitive to surrounding equipment that may produce vibrations or sounds near the same frequency as the ultrasonic signal. For more information, refer to *API Manual of Petroleum Measurement Standards*, Chapter 14.10.³⁰

It is important to note that meters can only be used when facilities have a dedicated high-pressure flare as opposed to a single control device (i.e., a flare that controls tanks, associated natural gas (ANG), and potentially other sources). Ultrasonic meters are also economically infeasible given they can cost \$20,000 to \$30,000 each to purchase, and additional capital required for installation and labor. API commented on this in our comments on NSPS OOOOb and EG OOOOc Supplemental Proposal, submitted on February 13, 2023, and included in Annex C of this letter. Furthermore, this does not include the cost to install SCADA communications systems that can cost up to \$100,000 per facility for unconnected remote locations.

[Proposed Parametric Monitoring Does Not Provide a More Accurate Alternative](#)

The proposed alternative of parametric monitoring does not provide a more accurate or cost-effective alternative to metering.

Based on operator experience, field testing programs comparing parametric monitoring and metered flare volumes have shown that parametric monitoring over-estimates flow volumes. Implementing parametric monitoring to estimate flow is complex and requires detailed data on the appropriate flow orifice diameter, installing additional instrumentation to monitor temperature and pressure difference across the orifice, as well as the need to install SCADA communication systems at remote locations and analytical software to estimate flow rate. The requirement to either install meters or parametric monitoring systems is burdensome and unnecessary considering that the main contribution to GHG emissions from flaring is unlit flares, which are addressed separately in the proposed rule.

For all the reasons stated above, **the Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations** that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.

²⁹ American Petroleum Institute (API), *Manual of Petroleum Measurement Standards, Chapter 14.10, Natural Gas Fluids Measurement – Measurement of Flow to Flares*, Second Edition, December 2021.

³⁰ Ibid.

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3.8.1.2 Proposed Flare Flow Measurement and Monitoring Requirements are Overly Burdensome

The cost and burden associated with measuring every stream is significant and understated by EPA.

Continuously measuring flow volumes or utilizing parametric monitoring devices for each source that routes gas to a flare will be extremely burdensome while failing to result in more accurate emissions reporting. Many operators have thousands of flares that would be affected, requiring either new meters or parametric monitoring devices. The majority of flares would require at least two gas streams to be monitored - the main vent line or "waste gas" stream and the purge/sweep/auxiliary gas stream. The cost and burden impact of monitoring – at a minimum – must include:

- Minimum of 2 or more specialized meters, or parametric monitoring systems
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the run for the meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

The capital and operational costs to continuously monitor flare volumes using meters or parametric monitoring devices, as proposed, would result in significant costs to reporters that were not adequately addressed in the proposed rule's burden assessment. EPA did not explain the cost estimates in Table A-3 of "Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," and we note that significant contributions to cost and burden were likely not included in the analysis based upon the magnitude of the estimate. As important, however, is the unjustified acceleration of installation of equipment that is already anticipated over the course of the next few years.

Paradoxically, this increased capital and operational cost can lead to flare volumes becoming less accurate than using the methodology under the current rule, as described below.

The requirement to continuously monitor at least two streams for thousands of flares at remote locations across the upstream oil and gas industry would require significant capital and operational expenditure with little benefit given the legitimate concerns regarding meter accuracy. As noted above, continuous monitoring flare flow volume would require costly specialized meters. As such, the Industry Trades believe EPA has underestimated the capital cost burden for purchase and installation of continuous parameter monitoring systems. The Industry Trades provided the Office of Management and Budget (OMB) this comment in response to Docket ID EPA-HQ-OAR-2023-0234.

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3.8.1.3 *Proposed Timeline for Flow Measurement or Monitoring is Unrealistic*

If EPA does not continue to allow process simulation and engineering calculation for flare flow volumes, we are concerned about EPA's proposed requirements to expedite the installation of additional continuous monitoring systems on flares.

The deployment of new continuous metering or parametric monitoring equipment can pose significant challenges. This is particularly true for extensive oil and natural gas production sites and midstream assets, as they often lack SCADA systems or comparable infrastructure. This deficiency limits the connectivity of in-field instrumentation and access to a data historian. Additionally, the absence of necessary infrastructure, such as electricity and data infrastructure including Wi-Fi and even cellular coverage, further diminishes any cost-effective means for installing new instruments.

Existing supply chain delays would only be exacerbated by requiring flow meters on flares as proposed. Operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for flow meters; these timelines are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. These timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. These supply chain challenges for flow meters and other equipment were documented in a blinded operator survey submitted to EPA on September 20th (and included in Annex E of this letter).

As noted in API's previous comments on NSPS OOOOb and EG OOOOc:³¹ "In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk. Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap." Like the supply chain delays, finalization of NSPS OOOOb and the potential need for flow meters under Subpart W would only exacerbate current installation timelines. Instead of requiring all flare stack emissions to install flow measurement by January 1, 2025 (less than 18 months between the proposed rule and the applicability date and likely less than 12 months from final rule) the proposed revisions should allow operators to transition to measurement data as it becomes available through the implementation of NSPS OOOOb or EG OOOOc, which will incorporate practicable implementation schedules for monitoring requirements.

3.8.2 Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **Double counting of emissions during periods of time when the flare is unlit should be avoided.** Because operators will identify discrete periods of time where the flare is operating with 0% combustion efficiency and report emissions accordingly, this volume of emissions should not be included in destruction/combustion efficiency (more in section 3.8.4 below).

³¹ Comment 5.2. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428>

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2. Monitoring for the presence of a pilot flame or combustion flame using a device capable of detecting that the pilot or combustion flare is present should **only be required for periods of time where there is flow of regulated material** going to the flare rather than “at all times.”
 - (i) It is illogical to track the length of time a flare is both unlit and there is zero flow because it has no impact on the estimated emissions.
 - (ii) Additionally, automatic ignition systems have been deployed by many operators and include a flame monitoring device. Since these devices include a flame monitoring device, they would satisfy the obligation, where EPA affirms the requirements for monitoring only apply during periods of flare flow. To reduce emissions or in areas where supplemental gas is needed because the well does not produce gas or enough gas, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare or the valve to the flare is closed. Some state rules, such as in New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA’s Supplemental Proposal “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources” Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).
3. **Additional monitoring flexibility will improve accuracy of reporting and should be afforded to the pilot monitoring.** The Industry Trades recommend either removing the sentence in 40 CFR 98.233(n)(2), stating “if you continuously monitor, then periods when the flare are unlit must be determined based on those data” or revising it to allow redundant and/or additional parametric monitoring or visual inspection to be used. This is because monitoring device malfunctions are not uncommon for thermocouples (or equivalent devices) resulting in false readings; however, other monitored parameters can confirm that the pilot is, indeed, lit even if the monitoring device errantly indicates the pilot is unlit. For example, operators that have flares with multiple thermocouples to monitor flame temperature report that the readings can be widely variable and have observed that the presence of a flame can be indicated by a single thermocouple within the installed group. There are also cases where a pilot has malfunctioned, but visual inspection using site visits or cameras on location reveal a robustly lit combustion flame. In extreme weather conditions, such as in Alaska, Wyoming, or North Dakota, the thermocouple reading will be affected by the ambient temperature and wind conditions. So, where a monitoring device indicates the absence of a pilot flame or combustion flame, an operator should have the option to confirm that finding through other means and eliminate that period from the log of time in which the flare is unlit if supported by other data.
4. As an alternative to thermocouple monitoring, the Industry Trades recommend that visual inspections can be performed using cameras on location.

The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA’s Supplemental Proposal “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources” Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).

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3.8.3 Gas Composition Requirements

Similar to the discussion regarding requirements for flow monitoring in this letter, the Industry Trades **urge EPA to retain the option “to use the appropriate gas composition for each stream of hydrocarbons going to the flare” in the absence of a continuous composition analyzer.** The proposed requirements to either use a continuous composition analyzer or take quarterly samples are both unnecessary (source flow composition is relatively stable at oil and gas facilities) and potentially conflict with the specific requirements and implementation timing of compliance assurance requirements in NSPS OOOOb and EG OOOOc.

EPA should provide an option to use process models for flared gas, which is how most compositions are currently being determined and with reasonable accuracy.

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA’s requirement that quarterly gas samples be pulled for each stream that goes to flare has no basis and was not addressed in the proposed rule’s TSD. The proposed requirement to install a continuous gas analyzer or take quarterly samples of the inlet gas to every flare is unreasonable and burdensome for several reasons.

1. **The gas composition is relatively stable over time rendering more frequent characterization of low value.** Flare gas composition in oil and gas operations is relatively stable and will not change significantly over time. As discussed above, the primary streams going to flare at typical oil and gas facilities include:
 - Pilot, purge, sweep, and/or auxiliary gas;
 - Low-pressure gas from tank flash, working, and breathing losses;
 - Mid-pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales; and
 - High-pressure separator flaring in areas with stranded gas pipeline take-away loss which is intermittent and decreasing across the country.^{32,33}

EPA also recognized that the gas composition could be stable by proposing an alternate net heating value demonstration in NSPS OOOOb and EG OOOOc³⁴. While Industry Trades commented that this demonstration should be simplified due to the relatively stable and generally sufficient heating value of the gas streams, its inclusion in the compliance assurance requirements of NSPS OOOOb and EG OOOOc recognizes that the gas streams could be demonstrated to be stable.

2. **EPA has not justified the costs related to the installation of continuous composition analyzers or quarterly sampling, and go beyond NSPS OOOOb and EG OOOOc compliance assurance requirements.** Installation of a continuous monitor for each stream or quarterly sampling will be

³² <https://www.api.org/news-policy-and-issues/blog/2022/05/24/reports-us-among-world-leaders-in-reducing-flaring>.

³³ <https://www.hartenergy.com/exclusives/us-reduces-flaring-and-flaring-intensity-world-bank-says-204724>.

³⁴ Proposed § 60.5417b(d)(1)(viii)(C)(1) to (5).

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extremely costly for installation, data gathering and management, calibration and maintenance or sampling and analysis for the thousands of flares impacted. Costs for continuous monitors include:

- Monitor(s) (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the continuous analyzer
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the monitor
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

For quarterly sampling, the associated costs include:

- Minimum of 2 sample ports (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting of the flare line for the sample ports
- Cost of gathering the samples each quarter
- Cost of analyzing the samples every quarter
- Data management system
- Data review and analytics
- Data entry for calculations

Flare systems in upstream operations are not designed for sampling, meaning that physical modifications to install sampling ports would be required to enable samples to be taken, which is costly and not always technically feasible. Also, installing sampling ports, meters/instrumentation, or continuous gas analyzers would require production to be shut down, which would be logistically challenging and generally result in flaring to accommodate causing more emissions.

As noted in API's comments on NSPS OOOOb:³⁵ "Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of \$164,000 to \$245,000." The estimated cost per gas sample was "\$1,500 to \$2,000 including shipping and analysis." Therefore, the annual cost for quarterly sampling could easily exceed \$10 million for an operator considering 4 samples per year per stream, at least 2 streams per site, and a thousand or more sites to sample annually.

³⁵ Comment 5.6.4. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428>.

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Finally, a continuous compositional monitor or quarterly sampling goes beyond the continuous net heating value (NHV) monitoring or NHV demonstration required under proposed NSPS OOOOb and EG OOOOc. As stated at the beginning of this section, Subpart W must not impose monitoring requirements beyond other applicable regulations. While a continuous compositional monitor could be used for NHV monitoring, compositional analyzers (e.g., gas chromatographs) are more expensive than NHV monitoring devices (e.g., calorimeters). Given the relatively stable composition of gas streams and cost for compositional monitoring, Subpart W should simply reference NSPS OOOOb and EG OOOOc monitoring requirement as they relate to methane destruction efficiency (see comments below) and not impose additional composition monitoring requirements.

3.8.3.1 Supply Chain Constraints

As noted above for flow meters, operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for monitoring equipment for flares; these delays are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. Requiring compositional monitoring under Subpart W would further exacerbate the existing supply chain constraints with minimal benefit to reported GHG emissions.

3.8.3.2 Technical Feasibility Issues

Additionally, it is technically infeasible to pull gas samples from low pressure flares. A positive pressure is required to pull gas samples from flare lines. Low pressure flare vent lines operate at near atmospheric conditions, which would either take hours to collect a large enough sample (i.e., fill a bag with enough gas) to send to laboratory for analysis or require a gas chromatograph equipped with a pump to be brought on location. Requiring a gas chromatograph to pull quarterly gas samples is economically infeasible.. Process simulation would be a more accurate representation of tank gas. It would be equally difficult to pull samples for mid- and high-pressure flaring given the intermittent nature of these events. A more accurate representation of high-pressure gas composition, as well as pilot/purge gas, would be sales gas composition which is ultimately what is being combusted at the flare. Finally, as stated above, EPA does not address why this frequency in sampling is being proposed in either the Technical Support Document or the preamble.

3.8.4 Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

3.8.4.1 NESHAP CC Requirements Are Not Applicable to Subpart W Flares

The reference to and requirements from refinery NESHAP CC are not applicable for Tier 1 reporting under Subpart W.

EPA should remove any tier requirement related to NESHAP CC for refineries because the characteristics of the flare designs, operating conditions, and composition variability are not representative of, and in fact quite dissimilar from, petroleum and natural gas systems flares.

The Industry Trades believe the reference to NESHAP CC which applies to petroleum refineries is inappropriate. There are numerous ways in which refinery and chemical manufacturing flares and flare gas differ from that of upstream and midstream.

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- Flare gas composition and flows span large ranges: Refinery flares receive flare gas of highly variable composition and of varying levels of heat content. Refinery flares can be dedicated to one or more related process units but are quite often very large and in service to many different process units, or even operate as a single interconnected system. Resultantly, the range of flows and composition to the flare is highly variable over a matter of hours. The heating value of the streams is typically much higher in upstream and midstream with the high-pressure gas being primarily natural gas and the gas from secondary separators, heater treaters and vapor recovery towers having a higher heating value greater than 2000 btu/scf. Except for the minority of wells that produce inert gases, where the composition of that production is known, flare gas streams are always highly combustible.
- Because refinery and petrochemical manufacturing flares combust gases with greater propensity to produce smoke (e.g., concentrations of olefins, diolefins, and aromatics) and thus are generally designed with an emphasis on smoke control, often including one or more steam addition systems, there is a documented risk of “over-steaming” for these flares. Less frequently, refinery and chemical manufacturing flares are air assisted, and even more rarely, unassisted. The reverse trend is true for upstream and midstream flares, where steam assist is the exception to the norm. Utilities to support steam assist are generally not available, upstream flares are less likely to need commensurate smoke suppression systems, and upstream and midstream flares are much smaller and dedicated units.
- While upstream operations are also actively seeking to reduce flaring, Refinery and chemical manufacturing flares also often have an obligation to flare gas minimization. Accordingly, any routine flaring that exceeds the flare gas recovery capacity of the facility results in flaring at extremely high turn-down conditions for the flare. High turn-down (<0.1% of flare capacity) at a steam-assisted flares presented the perfect storm for degraded combustion efficiency, which drove the enforcement initiative, subsequent ICR testing, and ultimately rulemaking to address this specific conditions. This condition does not exist in the up- and midstream segments.

3.8.4.2 EPA Should Allow Direct Measurement and Performance Testing for Flare Methane Destruction Efficiency

Direct measurement and performance testing by manufacturers or operators should be accepted as an optional demonstration of even greater destruction efficiency beyond 98%.

The Industry Trades request that EPA allow directly measured data, as well as NSPS performance testing by manufacturers or operators, as a more accurate approach to quantify an individual flare’s methane destruction efficiency. Whether or not a flare is monitored pursuant to NESHAP CC or NSPS OOOOb has no actual bearing on the flare combustion efficiency values. Even if a flare meets the monitoring requirements of either rule, it does not necessarily follow that the actual flare combustion efficiency is at the respective values. For example, flow volume values may indicate flow exceeding minimum or maximum flows which is an indicator of potential suboptimal combustion efficiency. Additionally, if all monitored flare values are within performance standards, the flare combustion efficiency could be higher than the specified combustion efficiency for the specified tier. As is standard practice with GHG estimation methodologies, the timing and values of detections, measurements, and parametric data—not whether monitoring requirements are met—determine emission rates, such as flare combustion efficiency. Thus, the Industry Trades recommend that EPA supplement the tiered monitoring approach to

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flare combustion efficiency reporting to include directly measured data or NSPS performance testing by manufacturers or operators.

Some operators are deploying emergent technologies to directly measure combustion efficiency (or the closely related destruction efficiency) for flares, such as Providence Photonics Mantis and Mantis light (additional information regarding this technology is available in Annex D). Many operators, either through state or permit requirements, or voluntarily, conduct more traditional stack testing to assure high combustion efficiency of enclosed combustors, which also meet the definition of “flare” in Subpart W. Both of those testing methodologies provide the most accurate estimate of any particular flare and should be allowed as an option.

EPA should also allow for the use of the recently finalized “Other Test Method (OTM 52): *Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities*,”³⁶ using Portable Analyzers to determine destruction or combustion efficiency.

These approaches would further support technology development and allow for flexibility in using advanced and evolving technologies. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program ([REMEDY | arpa-e.energy.gov](https://arpa-e.energy.gov)) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in flares. If technology development from this 3-year, \$35 million research program is successful, the ability to use a higher flaring efficiency value in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.8.4.3 Requirements for Proposed Tier 2 Support 98% Methane Destruction Efficiency

The compliance assurance provisions in NSPS OOOOb and EG OOOOc, as proposed under Tier 2, are sufficient to ensure 98% methane destruction efficiency.

The underlying goals of the flare compliance assurance provisions in part 63 subpart CC flare requirements was to supplement the provisions in 60.18 to specifically protect against over steaming, especially in concert with lower heat content flare gas by transitioning the compliance point from heat content of flare gas to heat content reaching the combustion zone, which would account for inert gases introduced to the flare gas within the variable gas composition in manufacturing settings, and account for the impact of steam on the combustion zone. In the absence of those conditions, 60.18 provisions continue to provide a reasonable assurance of high combustion efficiency.

Further, a recent study on flare destruction and removal efficiency (DRE) conducted in the Permian Basin by members of the Industry Trades indicates that over 85% of flares have a destruction efficiency above 98% (refer to comment below in Section 3.8.4.4). Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. These findings support a 98% combustion efficiency default for Tier 2, especially considering the enhanced monitoring requirements aligned with NSPS OOOOb rule requirements.

³⁶ https://www.epa.gov/system/files/documents/2023-09/otm-52_method-for-determination-of-combustion-efficiency-from-enclosed-combustors_clean_8_31_2023-004.pdf.

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3.8.4.4 Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed ‘combustion efficiency’ in Tier 3 reporting is based upon errant analysis in the Plant *et al* study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

The Plant *et al* published study results state that ‘the majority of flares function close to expected performance, with DRE values near 98%.³⁷ The study concluded that approximately **95% methane destruction efficiency was the average across the basins in the study without accounting for unlit flares**. Since Subpart W already requires the monitoring of and segregation of periods where flares are unlit, it is not appropriate to *also* include that condition in an average destruction efficiency assumption. The average observed DRE across the three regions of study is 95.2% and the average total effective DRE after accounting for unlit flares is 91.1%.³⁸ The lower ‘combustion efficiency’ proposed by EPA is not aligned with the methane destruction efficiency findings from the Plant *et al* study, and represents the inclusion of unlit flares, **meaning that the unlit flare contribution would effectively be double counted since unlit flares are reported separately**. Therefore, 95% methane destruction efficiency would be more appropriate for Tier 3 as supported by the study referenced by EPA (rather than 92%). This 95% destruction efficiency would be aligned with NSPS OOOO and OOOOa control requirements; requiring a Tier 3 efficiency of 92% would not be aligned with other applicable requirements.

Furthermore, in the Plant *et al* study, investigators did not have access to operational data, including flow information, for any of the observed flares. Resultantly, extrapolation of the observations to a regional emission factor inherently assumes that the set of flares observed well represented the population of flares in terms of size, design, and most importantly, flow rates. In the case of refinery and petrochemical plant flare combustion efficiency studies, it was found that flares most at risk for reduced combustion efficiency were those operating at high turndown (low flow) conditions. Low flows also result in reduced exit velocity, where higher exit velocities are more protective against cross-winds. Therefore, it is quite plausible that the majority of the flares encountered in the Plant *et al* study that were operating at reduced combustion efficiencies were flares at low flows. However, the authors applied the destruction efficiencies by *count* of flares to regional flare gas estimates from the Visible Infrared Imaging Radiometer Suite (VIIRS), which inherently incorporates an assumption that flare gas was evenly distributed among the observed flares and that flare turndown was not correlated to combustion efficiency degradation.

Validity of the Plant *et al* Study Data is Questionable

The validity of the Plant *et al* study data as the sole underlying basis for quantifying flare methane destruction efficiency is questionable.

There are several limitations of the Plant *et al* study, most of which are raised by the authors themselves within the study and quoted below. These limitations raise questions about the study validity as a basis for establishing a 3-tier combustion efficiency framework and a presumptive Tier 3 value of 92%. These include:

³⁷ <https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf>.

³⁸ *Ibid*.

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- The study design did not disclose how the flight-path test method (i.e., ‘shifting racetrack’ pattern) was validated, for example, using a well-characterized source of CO₂ and CH₄ or a test flare having known input flow rates, combustion characteristics, and dispersion behavior. Without documentation of method validation using a model source, peer reviewers were, and end-users are, unable to determine how the field sampling techniques were calibrated, and the appropriateness of the error correction / statistical treatment applied to the collected information to address test method-induced artifacts.
 - There were no data presented on the vertical or horizontal dispersion effects or on the ability of the sampling technique to discern the presence of imperfect distribution of CH₄, CO₂ or other components within the sampled plumes. In fact, in the Supplementary Materials³⁹ the authors noted that (emphasis added), “In real-time, the concentration reading of CO₂ was monitored to look for an intercept (i.e., peak) of the *relatively narrow flare combustion plume as the aircraft transected downwind. If an intercept was not identified on the first downwind pass, the flight team adjusted altitude, using the visual flare as a guide.*” This statement confirms that each sample event would likely have employed a unique flight path, introducing an inconsistency across individual runs in the dataset.
 - The sampling scenario was challenging. As noted in the Supplementary Materials⁴⁰, “In real-time, the concentration reading of CO₂ was monitored to look for an intercept (i.e., peak) of the *relatively narrow flare combustion plume as the aircraft transected downwind.*” No information was available to readers to determine the parameters of each flight path. Using publicly available information for the aircraft and assuming a circular flight path, the estimated dwell time of the aircraft in the plume during each pass was likely extremely short. The Scientific Aviation Mooney aircraft have a cruise speed of 170 knots (or higher)⁴¹ with stall speeds of 50-60 knots^{42,43} according to various sources. At a speed of 130 knots⁴⁴ in a 6500ft diameter circular flight pattern, and assuming a 10° sample window (570ft), the dwell time in the sample window is less than 2.5 seconds. Even with a wide 22.5° sample window (1275 ft), the dwell time in the sample window is just 5.5 seconds. Higher air speeds would shorten the dwell times.
 - The study acknowledged that the log-normal curve-fitting technique used likely leads to overweighting the importance of the outlying data, thus magnifying the influence of tails even though the authors noted that the median observed DRE values were close to 98%. Also, the authors could not explain the outlying, tail-defining observations collected (emphasis added), “Investigations into possible drivers of reduced DRE... did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets *cannot explain most of the observed flare CH₄ DRE variability.*” Also, the authors did not solicit input from operators about operating conditions that could explain the observed
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data. Given the influence of the low DRE datapoints, further scrutiny as to their validity and possible exclusion from the dataset should have been made.

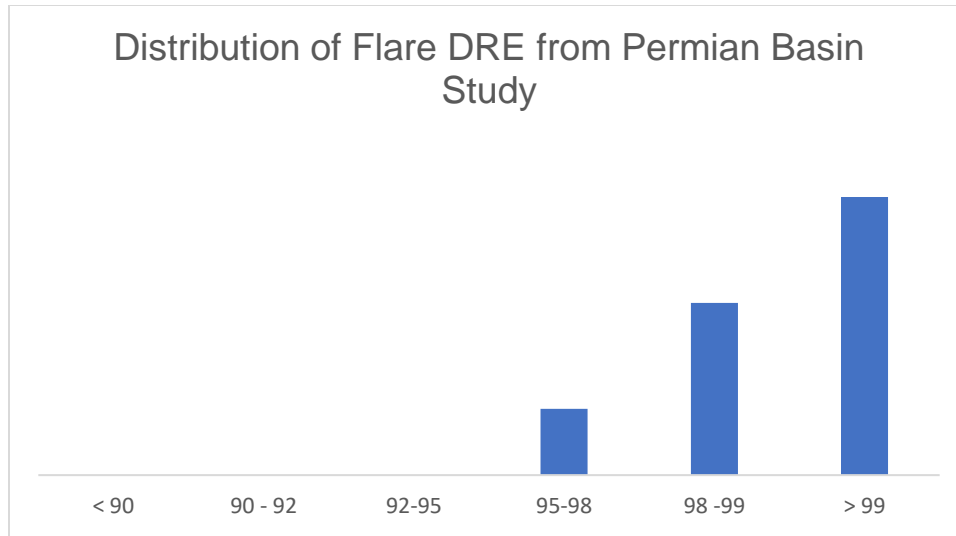
- The Plant *et al* study did not provide information on the rate, duration and variability of the gas being flared at each location, nor what activity precipitated the flaring, such as: flowback from a single well, emergency operations during drilling or a workover, a lightning strike that shut down control systems, a gas compressor failure, malfunction of a tank or separator liquid level or other controller, on a well pad co-located with the flare or at a central gathering and boosting facility, upset at a gas treating unit co-located with the flare, shut-in of a downstream gas plant forcing gas to be flared from multiple upstream sources etc. Absent this information, it is impossible to determine what separated high-performing flares, from those that exhibited low DREs and whether the low-performing flares represent the effect of transient anomalies that cannot be assumed to be present basin-wide for extended periods of time.
- The use of “bootstrapping sampling” to extend to basin-scale the data from the limited sample set collected via aircraft sampling magnifies the weaknesses discussed above and should not be the basis for a regulatory change. The Plant *et al* study authors combined contributions of both observed inefficient **performance (i.e., CH₄ DRE) and the prevalence of unlit flares into a total effective DRE.** This was done by randomly resampling (with replacement) the observed DRE distributions and applying those efficiencies to the population of flares seen in VIIRS within each basin. Essentially, this manipulation of the data multiplied the small observed dataset many times over. Then the authors ***inferred the uncertainty*** (emphasis added) of basin-average estimates to derive 95% confidence intervals. This approach does not support the use of the word “found” in the following statement made in the preamble: **“Plant *et al.* ... *found* average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin.”**

Member-Provided Data Supports a Destruction Efficiency Well Over 95%

Additional flare destruction efficiency data provided by Industry Trade members indicate that all but two flares out of 132 tested achieve a destruction efficiency of over 95%, with the majority (nearly 90%) achieving a destruction efficiency greater than 98%.

In September 2023, API members conducted a flare study on 39 flares throughout the Permian Basin using Providence Photonics Mantis. Due to the limited timeframe in which to prepare comments, this study was limited to 39 flares; however, the study found that 85% of flares achieved a destruction efficiency greater than 98%. All flares achieved a destruction efficiency greater than 95%, as shown in the Figure below.

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Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, and one measurement in the Permian, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. All but two flares out of 92 tested had a destruction efficiency above 95% (i.e., 94.85% and 90.52 %, respectively). The table below summarizes the distribution of methane destruction efficiencies calculated from member-provided flare testing in both the Permian and Bakken basins:

Basin	Number of Flares Tested	Mean Flare Destruction Efficiency, %	Median Flare Destruction Efficiency, %
Permian	40	98.82	99.05
Bakken	92	99.27	99.69
Combined	132	99.14	99.50

As shown, the median flare destruction efficiency for the combined dataset of 132 flares tested from the Permian and Bakken was 99.5%. **These studies further reinforce that the Tier 3 destruction efficiency should be a minimum of 95%. Arguably, the Tier 3 destruction efficiency should be considerably higher than 95% based on the test data from members, as the data supports a destruction efficiency closer to 98%.** Please see Annex D for a summary of the test results.

3.8.5 Completion Combustion Devices Should not be Subject to Proposed 98.233(n) Requirements for completion combustion devices used during completions with hydraulic fracturing should not be required to have the same monitoring provisions as flares under 98.233(n).

For completions with hydraulic fracturing in 98.233(g), EPA has proposed operators to follow the requirements listed in 98.233(n), which include extensive monitoring requirements. Under existing air quality regulations and proposed NSPS OOOOb, combustion of emissions that cannot be routed to sales, such as for wildcat or delineation wells, are combusted using a completion combustion device. This equipment has a separate definition and compliance assurance requirements from typical control devices based under NSPS due to the temporary use of these devices during a completion event. The proposed requirements under 98.233(n) are inappropriate and EPA should, at a minimum, have

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appropriate provisions that allow engineering estimates for completion combustion events. Completion combustion devices must be equipped with a reliable continuous pilot flame under NSPS.

3.8.6 Disaggregation of Flare Emissions

When data is not available to allow disaggregated reporting by individual sources controlled by a flare, EPA should allow aggregated emissions reporting by flare.

The Industry Trades understand that EPA wishes to allocate all individual sources controlled by a flare back to the contributing source. The Industry Trades support maintaining the ability to report emissions aggregated by flare when more accurate data is not available. As addressed in the “Flares” section of this document, metering individual sources may not result in more accurate data. Allowing the flexibility to continue reporting flare sources aggregated will give companies the ability to report the most accurate data available given a particular facility’s operational design. However, it is important to note that EPA has not stated a clear benefit from requiring the disaggregation of sources, and therefore a true cost/benefit analysis cannot be determined.

3.9 Centrifugal and Reciprocating Compressor Venting

3.9.1 Measurements in Not-Operating-Depressurized Mode

The Industry Trades support EPA’s efforts to increase the accuracy of reported information for venting from centrifugal and reciprocating compressors by allowing direct measurement, but measurement should not be required in Subpart W if not required in other regulatory programs. Additionally, Subpart W should not force operators to measure emissions in a not-operating depressurized mode.

EPA’s proposed expansion from an emission factor to measurement approach for onshore production and gathering and boosting will further improve the quality of reported emissions across the segments. The Industry Trades support the expanded assortment of measurement methodologies and appreciate EPA’s use of data from other programs (e.g., proposed NSPS OOOOb and EG OOOOc) for emissions calculations under subpart W, however there are numerous issues with the proposal. Although the compressor measurement provisions have been expanded from the gas processing reporting source category to include onshore production and gathering and boosting, there are unique differences that should be accounted for within the proposed requirements. The Industry Trades have provided suggested edits to account for these differences.

EPA is proposing to require that onshore production and gathering and boosting operators shall measure at least one-third of their reciprocating and centrifugal compressors subject to NSPS OOOOb in not-operating-depressurized mode each year. The Industry Trades do not support this requirement for several technical, safety and practical reasons. The Industry Trades recommend that EPA align with proposed NSPS OOOOb and EG OOOOc and limit the measurements to the rod packing for reciprocating compressors and dry seal vents for centrifugal compressors. Testing the compressors in a not-operating depressurized mode is unnecessary and very difficult to implement for the following reasons:

- Forcing a unit into a not-operating depressurized mode will result in unnecessary venting of methane emissions to the atmosphere and could pose an unnecessary safety risk to the testing personnel or others at the site. Operations in upstream production and gathering and boosting segments are characterized by stable operation with full utilization of installed compression capacity. In order to measure emissions in not-operating depressurized mode, a forced

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blowdown event leading to significant methane emissions would be required for these compressors.

- As a practical matter, it would be very difficult if not virtually impossible for an operator to know at which point during the year to force units into a not-operating-depressurized mode in order to reach a prescriptive annual target. Additionally, the number of units change on a frequent basis due to acquisitions/divestitures, such that the number that would constitute “one-third” changes from month to month. Compressors are also added and removed throughout the year to address operation needs from the wells and gathering system based on production rates.
- In the dynamic operations of upstream and midstream oil and gas, shutting down a compressor for the sole purpose of measuring the venting could result in shut-in and blowdown of other process equipment resulting in additional methane emissions, as well as costly prolonged downtime of a facility. Taking a compressor off-line in production and gathering and boosting segments would result in shutting in a well(s), which can be problematic to restart and regain stable operation. As anecdotal evidence, our members have noted these tests take upwards of three weeks at their 10 gas plants with 140+ compressors. Extending this requirement to upstream facilities that are geographically spread across hundreds of miles would be extensive due to the thousands of compressors in use. The gas plant measurements are streamlined due to the units being co-located and the designed redundancy in place.
- Additionally, due to the integrated nature of the upstream/midstream environment, shutting down compression would not only have an effect on that company, but would additionally impact other companies that are connected to the system (i.e., shutting a compressor down would cause high pressure issues for the upstream operator and low-pressure issues for the downstream operator potentially resulting in additional flare and/or vented emissions for additional companies.
- Methane emissions from compressors in not-operating depressurized mode represent the emissions across the isolation valve, with potentially high flow rates due to the extreme line pressure on the upstream, pressurized side of the valve. Many operators, especially in production and gathering and boosting segments, do not normally operate compressors in this mode due to the potentially large methane leakage and associated safety risks. Additionally, good operating practice is to leave the blowdown/depressurization valve closed when units are offline.
- Finally, many compressors serve a critical function in the electricity generation supply chain and operate with limited or no excess capacity; forcing operators to shut down units to take measurements in a not-operating depressurized mode could strain the electrical generation supply chain. In 2022, the Texas Railroad Commission (TRRC) adopted weatherization rules for natural gas facilities to protect gas flow to power generators and ensure that residents have electricity during weather emergencies. The new rule requires critical gas facilities to weatherize, to ensure sustained operation during a weather emergency. The testing requirements as described would add an additional layer of complexity with little to no emissions reporting accuracy improvements.

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3.9.2 Alignment with NSPS Protocols – Measurement of Compressor Sources

In the proposal for NSPS OOOOb, rod packing, and seal vents are the only compressor sources that require monitoring. All other compressor leaks would be captured during the fugitive emissions inspections. The Industry Trades recommend that EPA align with the monitoring and fugitive emissions requirements of NSPS and consider leaks from other sources (e.g., blowdown valve leakage) fugitive leaks. This modification would eliminate the need for specific compressor mode testing and align with other EPA regulations for other sources.

3.9.3 Emission Factor Methodology- Utilize Measurement Data Reported Under Subpart W for Onshore Production and Gathering and Boosting

EPA should utilize the vast dataset of historically reported compressor measurements in different operating modes to derive population emission factors to ease the burden of compressor measurements and reclassify leakage from isolation and blowdown valves (open-ended lines) as equipment leaks.

While we believe all leaks besides rod packing and seal vents should be captured under the fugitive emissions reporting, EPA could consider an alternative to the measurement protocol. This alternative could utilize the vast dataset of compressor measurements in different operating modes historically reported under Subpart W to derive emission factors to reduce the burden of compressor measurement requirements. Because of the large sample size of actual measurement data, methane emissions can be reasonably estimated using emission factors derived from the data reported Subpart W.

Additionally, EPA should consider the use of the historically reported Subpart W compressor leakage dataset to derive population emission factors rather than rely on the much smaller dataset from the Zimmerle *et al* study.

3.9.4 Alignment with NSPS measurement provisions should extend beyond onshore production and gathering and boosting industry segments.

Industry Trades support referring to the data made available through the provisions located at §60.5380b(a)(5) for centrifugal compressors and §60.5385b(b) and (c) for reciprocating compressors at onshore production and onshore natural gas gathering facilities, but do not support incorporating measurement requirements in Subpart W. The Industry Trades recommend that EPA should also do the same for any compressor subject the NSPS OOOOb or EG OOOOc, including those located at onshore gas processing, natural gas transmission and underground storage. Without this alignment for all compressors subject to the NSPS, many operators will be required to calibrate measurements according to two separate standards, which we do not believe was EPA's intent.

3.10 Equipment Leaks

3.10.1 Method 2- Site-Specific Leaker Emission Factors

EPA should allow more flexibility in the requirements for developing site-specific emission factors for equipment leaks.

The Industry Trades support EPA's proposal to allow for directly measured data to develop site-specific emission factors in lieu of the default leaker or population emission factors for equipment leaks. However, the Industry Trades recommend allowing more flexibility in allowing representative direct measurements rather than "site specific." For upstream operations, there can be many components that

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are representative even if they are not located at the same facility; and the same can be said for the gathering and boosting reporting segment. The Industry Trades recommend that EPA allow representative leak measurements where “representative” could mean components in gas or oil service, component types, and other considerations – but not otherwise limited to a single well pad or boosting and gathering ID.

The number of leak measurements required to develop site specific emissions factors, proposed as a minimum of 50 per component type, is arbitrary; accumulating 50 leak measurements will be difficult for less frequently used component types or operators with fewer sites. The Industry Trades recommend that EPA allow operators flexibility to determine an appropriate sample size using an appropriate statistical approach based on the complexity of the sites (based on variability of the streams at the sites) and available data and modify as more measurements are obtained. The requirement for a sample of 50 leak measurements per component type will penalize small operators with few sites, as the minimum requirement of 50 may not be possible. Further, as operators convert pneumatic systems to air or electric controllers, fewer sites will have natural gas-operated pneumatics. The Industry Trades also recommend allowing multiple years upon which operators can collect measured leak data and refine those factors as more data is available; this will ultimately be more accurate and representative of site conditions than default emission factors that were derived from larger data sets.

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3.10.2 Method 1- Default Leaker Emission Factors

The derivation of the proposed OGI leaker emission factors is unclear and values appear high relative to the underlying studies and would overstate emissions from the more prevalent non-compressor related components.

The Industry Trades support the use of data from the Pacsi *et al* study to develop the leaker emission factors. However, we are concerned about the significantly higher emission factors that EPA has derived from the Pacsi *et al* and Zimmerle *et al* studies, especially for OGI leak detection, as compared to the existing Subpart W and Pacsi *et al* leaker emission factors. When comparing the published study results from Pacsi and Zimmerle to the EPA proposed emission factors (see comparison table below), it is unclear how the proposed emission factors were derived and while a generalized description is provided in the TSD, the supporting calculations are necessary to fully understand the approach EPA has taken.

Component	EPA Proposed Emission Factors (scf/hr/component)			Pacsi et al (scf/hr/component)	Zimmerle et al, (scf/hr/component) ^a	
	OGI	Method 21 @ 10,000 ppm	Method 21 @ 500 ppm		Non-compressor components	Compressor components
Leaker EFs, Gas Service – Onshore Production & Gathering and Boosting						
Valves	16	9.6	5.5	6.0	7.1	36.9
Flanges	11	6.9	4.0	13.7	6.2	8.8
Connectors	7.9	4.9	2.8	2.8	4.7	11.9
OELs	10	6.3	3.6	8.5	3.94	
PRVs	13	7.8	4.5	1.1	10.0	18.5
Pump Seals	23	14	8.3	-	29.9	
Other	15	9.1	5.3	4.2	21.7	
Leaker EFs, Oil Service – Onshore Production & Gathering and Boosting						
Valves	9.2	5.6	3.3	4.9	7.1	36.9
Flanges	4.4	2.7	1.6	-	6.2	8.8
Connectors	9.1	5.6	3.2	1.1	4.7	11.9
OELs	2.6	1.6	0.93	-	3.94	
Pump Seals	6.0	3.7	2.2	0.23	29.9	
Other	2.9	2.2	1.0	12.7	21.7	

^aZimmerle *et al* study published results did not distinguish between gas and oil service.

As shown in the table above, the Zimmerle *et al* study data show and the study report indicates that emissions from compressor-related components have higher leak rates due to vibration. Since EPA did not distinguish between components associated with or not associated with compressors, the average emission factors proposed that appear to include compressor-related components would overstate emissions from the more prevalent non-compressor related components. The Industry Trades request that EPA critically review the derived emission factors and include compressor-related components in the breakdown of leaker emission factors, with commensurately lower emission factors for non-compressor-related components, to avoid significant overstatement of methane emissions from the higher population of non-compressor related components.

Applying gathering and boosting derived emission factors to onshore production with compressor-related component emissions included in the Subpart W emission factors would significantly overstate

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methane emission because far fewer compressors are operational in production compared to gathering and boosting operations.

The Industry Trades support efforts to properly characterize a leak by the period in which that leak is detected. This will further align subpart W with the proposed methane rule, which mandates that any leaks must be repaired as soon as practicable. To that extent, we recommend EPA amend the definition of $T_{p,z}$ in Equation W-30 to better reflect the implementation of monitoring and repair programs by acknowledging that the duration of the leak may be subject to the action of repair and verification, and not solely by a traditional survey and/or the start or end of the reporting year, similar to what the Industry Trades propose for other leak durations, thief hatch openings, etc.

We also recommend that EPA revise the approach to include other activities in addition to leak detection surveys that may offer an indication of a repaired leak. While the current proposed language refers only to a “survey”, an operator will have other clear indicators that a leak has been addressed including the repair date or other detection approach. EPA should include any other such activity on which an operator seeks to assign a repair date other than a survey as a reporting element.

3.10.3 Enhancement Factor

EPA’s ‘Enhancement Factor’ or ‘k factor’ derivation and rationale are unclear; testing of the proposed approach using the underlying study data to corroborate results should be confirmed.

EPA states in the TSD that the Pacsi *et al* study OGI captured approximately 80% of overall emissions, Method 21 (500 ppm leak detection threshold) captured 79% of emissions, and Method 21 (10,000 ppm limit) captured 65% of emissions, respectively. However, the Pacsi *et al* study is clear that even though using Method 21 identified more leaks (293 vs. 113 with OGI), the majority (67%) of additional leaks found were very small (1 scf/hr. or less). Further, both FID and OGI methods, while finding different leaking components, found a very similar total volume of emissions from leaking components at the site.

The Industry Trades disagree with EPA’s proposed “Enhancement Factor” or “k” factor. It seems that EPA has proposed the “k” factor to account for both method’s quantification differences as well as other variables, such as the percentage of emissions found by survey methods (e.g., due to accessibility of components, etc.). Applying such logic to specific emission factors for specific equipment is not appropriate as the intent seems to include both updates for a specific leak factor for an individual component as well as capturing emissions from other components that may not be otherwise detected (i.e., the remaining 20% or 21% of emissions not directly identified by OGI or M21 respectively in the Pacsi *et al* study). Grossing up individual component emission factors is not a logical approach to account for leaks not directly identified. While the Industry Trades disagree in principle with EPA’s approach, if such an approach were to be applied, it would only be appropriate on an aggregate basis. That is, if EPA were to apply such logic, doing so as part of the National Inventory process would be more appropriate than grossing up emissions from individual components or individual operators.

Additionally, and importantly, the Industry Trades have been unable to replicate the calculations EPA used to derive the “k” factors and request transparency regarding the approach and use of data relied upon by EPA prior to finalizing any rulemaking. The Industry Trades also request confirmation if EPA tested their “k” factors by applying to the M21 data in order to recalculate the emissions at site level using study data and confirm if it matches with the measured emissions.

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3.10.4 Leak Duration

The leak duration should be revised to reflect a more reasonable and representative assumption that the leak duration is half the time since the last survey.

The leak duration associated with the Method 1 leaker emission factor approach should be half the time since the last survey. Assuming that the leak duration was the entire period since the last survey is an overstatement of the leak duration, as it implies the leak occurred on the date of the last survey which is unreasonable. Since the actual time the leak started is unknown, it is more reasonably accurate to assume that, on average, that the leak would have started in the mid-point of the survey cycle. This assumption accounts for that some leaks will occur before the mid-point and some will occur after the mid-point, but that on average, it is a reasonable assumption and much more representative than the conservative assumption that the leak started at the time of the last survey.

3.10.5 Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

The Industry Trades are concerned that the Rutherford *et al* study (2021) used for the production and Gathering and Boosting emission factor development included infrequent large emitters in the derivation of the emission factors, including emissions from sources covered elsewhere and not considered fugitive components. Additionally, Rutherford *et al* didn't conduct any actual measurements of equipment leaks. The study results are a synthesis of past studies and includes storage tank emissions as fugitives. Given that EPA is now proposing to report large events as “other large releases,” the Industry Trades believe using this study will result in double-counting. The Industry Trades support the use of the Pacsi *et al* and Zimmerle *et al* studies, despite EPA’s concerns noted in the preamble regarding the smaller sample size. The Industry Trades believe the Pacsi and Zimmerle studies to be more appropriate for upstream and midstream operations.

The Industry Trades do not support the elimination of component count method 2 and request that EPA allow the use of actual component counts if it is subject to a state regulatory program that requires component counts.

3.10.6 Leak Detection at Onshore Gas Processing

Industry Trades generally support the updated definition of onshore natural gas processing that align with New Source Performance Standards as proposed in 98.230(a)(3). This update provides the regulated community with much needed alignment between regulatory programs and removed the confusion for reporting emissions under subpart W based on the previous definition included in the GHGRP.

However, the Industry Trades request that **CO₂ plants be included within the Onshore Gas Processing segment definition**, and not under the Gathering and Boosting definition.

Additionally, there are additional clarifications that are needed from EPA to the proposed equipment leak provisions as it pertains to onshore gas processing to better align with existing and proposed NSPS provisions.

The proposed use of NSPS OOOOb and EG OOOOc surveys for calculating emissions should be clarified and expanded.

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EPA has proposed the following text at 98.233(q)(1)(vi)(F) to require the use of NSPS OOOOb and OOOOc survey data in calculating emissions from equipment leaks at onshore natural gas processing plants:

For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.

Industry Trades recommend the following updates to this requirement:

- **Inclusion of alternate leak standards:** References to § 60.5400b should also include a reference to the alternate equipment leak standards in § 60.5401b to clarify that both OGI surveys conducted according to Annex K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations.
- **References to the equipment leak standards under the earlier NSPS KKK, OOOO, and OOOOa** should be included so that survey data can also be used in emission calculations. While the earlier equipment leaks standards were for VOC only as opposed to the VOC and methane under NSPS OOOOb and EG OOOOc, some components in VOC service (≥ 10 wt% VOC) may also be required to be surveyed under Subpart W (≥ 10 wt% CH₄ + CO₂), and the monitoring technique in the earlier NSPS are already included in the approved list in 98.234(a). This update would allow operators to avoid potentially duplicative surveys.
- **The inaccessible component exemption should be retained under Subpart W.**⁴⁵ For onshore gas processing, the term “Inaccessible” has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 98.234(a). This exemption is directly linked to the safety of our personnel or the technical use of monitoring equipment. Specifically, connectors that are “buried” or that are “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

⁴⁵ EPA has proposed the following language per 98.234(a): Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year. For components located in the onshore production, natural gas gathering and boosting, transmission compression and underground storage (i.e. well sites, central production facilities, or compressor stations), the language proposed aligns with those that are identified at difficult-to-monitor when using M21 per the provisions in NSPS OOOOa and proposed NSPS OOOOb/c. The difficult-to-monitor components require annual monitoring under NSPS, which are consistent with the proposed language in 98.234(a). EPA could be consistent and use the term difficult-to-monitor if that was EPA’s intent.

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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)" should not require additional leak detection provisions under subpart W.

3.10.7 Expand List of Approved Monitoring Technologies

The list of approved monitoring technologies should be expanded to include alternative periodic screening and continuous monitoring technologies.

Under proposed NSPS OOOOb and EG OOOOc⁴⁶, operators have the ability to use EPA approved alternative periodic screening or continuous monitoring technologies to satisfy the equipment leaks for well sites, centralized production facilities, and compressor stations. The Industry Trades have provided previous comments⁴⁷ on how to improve these proposed alternative technology provisions.

Furthermore, results from alternative technology surveys could not be used for Subpart W emission calculations as proposed. Therefore:

- Operators would need to conduct an annual OGI or M21 survey for Subpart W for components subject to NSPS OOOOa/b/c or for other components if they elected to not use the population emission factors. This annual survey could be beyond what is required under NSPS.
- Results from use of alternate technology under NSPS OOOOb or EG OOOOc would be reported under large emissions release if thresholds were exceeded under Subpart W.

These two consequences would disincentive the use and development of alternate leak detection technologies. Therefore, 98.234(a) should be updated to include: "Periodic screening or continuous monitoring as specified in § 60.5398b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter..."

3.10.8 Component Applicability

The Industry Trades support EPA's proposal to exempt "components in vacuum service" from the equipment leak provisions in 98.233(q) and (r). These components have been historically exempt from the NSPS leak detection standard since no fugitive leaks are expected. However, we do not support inclusion of reporting requirements that include reporting of component counts for components in vacuum service.

3.11 Other Large Release Events

The Industry Trades support inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins, and literature has demonstrated that they can have an outsized impact on total emissions. However, both the threshold and triggers for inclusion of an event based on credible information are problematic. Furthermore, in many cases it will double count emissions reported elsewhere in the regulation.

⁴⁶ Proposed § 60.5398b and § 60.5398c.

⁴⁷ The Industry Trades have provided previous comments on how to improve these proposed alternative technology provisions. See Comment 3.0. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428>
<https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-3819>

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3.11.1 Other Large Release Events Threshold

3.11.1.1 *Instantaneous Rate of 100 kg/hr is Not a Meaningful Threshold*

A threshold of an instantaneous rate of 100 kg/hr should be paired with a duration in order to ensure that the observation is, indeed, associated with a large release event. A measurement report of an instantaneous rate of 100 kg/hr should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event.

EPA explains that it “is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH₄ emissions reported by facilities to subpart W.”⁴⁸ “These revisions include proposing to add a new emissions source, referred to as “other large release events,” to capture large emission events that are not accurately accounted for using existing methods in subpart W.”⁴⁹ An “other large release event” would be defined to include any event that exceeds an instantaneous methane emissions rate of 100 kg/hr or exceeds 250 mt CO₂e for the entire event.⁵⁰

EPA further explains that the 250 mt CO₂e event-based threshold is based on a comparison to the Aliso Canyon event and other release scenarios that EPA considers to be objectively large. EPA asserts that the 100 kg/hr instantaneous emissions rate threshold is appropriate because it would “align with the super-emitter response program proposed in the NSPS OOOOb” and would “provide a means to get information for these large, shorter duration releases.”⁵¹

The proposed reporting thresholds for “other large release events” are flawed for two reasons. First, EPA fails to provide any explanation of whether the reporting thresholds are appropriate or necessary for purposes of implementing the WEC. As explained above, the key purpose of the Proposed Rule is to provide information necessary for implementing the WEC. There are obvious questions that should be asked and answered by EPA as to how the type and scope of “other large release events” that would be required to be reported under the Proposed Rule squares with implementation of the WEC. EPA’s views on the relationship between the proposed reporting thresholds and implementation of the WEC are necessary for EPA to fully assess the impact of the Proposed Rule and to allow for commenters to assess EPA’s reasoning and provide informed input.

Since oil and gas emissions are highly variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate as is typical, merely provides information regarding potential observations of far less than the represented hour in most cases. This is because an emission source with duration greater than 1 hour may have a variable rate over that hour or an emission source may resolve in far less than the hour. An instantaneous threshold of 100 kg/hr methane could result in numerous objectively small emission events (especially compared to an objectively large event release of at least 250 mtCO₂e). An emission duration, assuming perfect observation and consistent emission rate of 1, 100, or even 1,000 times the <1 minute observation period for many technologies (assume 1

⁴⁸ 88 Fed. Reg. at 50284.

⁴⁹ Id.

⁵⁰ Id. at 50296.

⁵¹ Id. at 50296-7.

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minute here), would result in emission event quantities of 0.05, 4, or 42 mtCO₂e or 0.02%, 2%, or 17% of the corresponding 250 mtCO₂e threshold. In fact, it would take nearly 5 days of a constant emission rate of 100 kg/hr to accumulate emissions of 250 mtCO₂e, of which there is no reasonable extrapolation of an instantaneous remote sensing emissions event.

Therefore, an instantaneous rate of 100 kg/hr is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple intended and accounted for emissions have transient large emission rates (blow downs, drilling completions, liquid unloadings, etc.). Such data should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event emissions.

3.11.1.2 Other Large Release Threshold Needs to be Modified

If Other Large Releases Remain in the Rule, Modify the Threshold

At a minimum, the Industry Trades recommend that EPA modify the threshold for this category in 98.233(y)(1)(i) as follows (and modifying 98.233(y)(1)(ii) as applicable):

- (i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that ~~either~~:
 - (A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ and
 - (B) Emits combined GHG across the entire event duration of 250 metric tons of CO₂e or more.

Requiring both thresholds be met would catch large releases discussed in the proposed rule's TSD, such as well blowouts, while also easing the burden on reporters to assess relatively smaller emission events, such as PSV releases that occur over a few seconds to minutes.

If EPA does not change the threshold as recommended below, the Industry Trades recommend that a duration of 100 hours be paired with the instantaneous rate of 100 kg/hr, which is commensurate with a duration at that emission rate that would result in 250 mtCO₂e of

3.11.2 Detection Technology Must be Approved by the Super-Emitter Response Program

Furthermore, the Industry Trades are requesting that EPA clarify that the rate of 100 kg/hr is determined with only advanced detection technology and third parties approved by EPA through the SERP in NSPS OOOOb and not based on presumptive calculations, models, or ground sensors which have varying levels of uncertainty. Furthermore, if industry is not approved to use the technology for compliance with OOOOa, OOOOb, or OOOOc, the technology should not be required to be used for reporting purposes under Subpart W and used to determine fees under the WEC. Requiring this will discourage voluntary monitoring by companies, discourage new technology development, and include potentially highly inaccurate data to be the basis of the WEC.

3.11.3 Other Large Release Events Duration

EPA is proposing that reporters must assume a leak duration of 182 days if the start time of an event cannot be determined based on "monitored process parameters." EPA has no basis for using 182 days.

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As noted in the proposed rule's TSD, typical durations for large releases are several hours to several days. The Industry Trades believe this 182-day assumption is derived using average leak duration data including a significant statistical outlier event⁵² that should be excluded from calculated averages, most notably because the time it took to resolve the leak was not due to lack of awareness of the leak, but rather the complexity of resolving the leak. Accordingly, the Industry Trades disagree with EPA's statement in the TSD that the duration should not be shorter than the Aliso Canyon event. Besides it being a known event, EPA is proposing a default leak duration even longer than that statistical outlier event (111 days vs. 180 days).

The Industry Trades recommend a duration of half the time since the last optical gas imaging inspection, or the time since operator inspection of the source in question (e.g., operator rounds that proactively include flare, thief hatch or other inspections), site level measurement campaign, continuous monitoring system, or other monitoring data, or a maximum of 30 days if no other data is available. The maximum duration of 30 days is a conservative estimate consistent with (a) EPA's acknowledgement in the TSD that "Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days (Chen *et al.*, 2022; Wang *et al.*, 2022)", and (b) that most well sites are expected to have operator rounds occurring more frequently than every 30 days and, further, the odds of a significant event going unnoticed by both an operator and 3rd parties (satellite, etc.) are unlikely.

Furthermore, the Industry Trades believe that additional clarification and flexibility needs to be provided for "monitored process parameters." This is particularly critical for very short emission events for which telemetry may not be available or reliable. The Industry Trades are concerned that any ambiguity around this requirement could result in vast over-reporting of emissions by assuming a duration of 182 days. Monitored process parameters are not defined in the rule, but in 98.236(y)(4) EPA says that this includes "pressure monitor, temperature monitor, other monitored process parameter (specify)." The Industry Trades recommend clarifying this by allowing reporters to use additional process parameters, such as site inspections, cameras on location, etc. that confirm the event duration.

3.11.4 Credible Information

EPA is proposing that operators must report emissions from other large release events if they have "credible information" that a large release event has occurred. The Industry Trades are concerned that requiring reporters to use all credible information, especially where credible information in this context is ill defined, may disincentivize voluntary monitoring with emergent technologies where leaks could be discovered, but may have a large range of uncertainty (generally associated quantitative emissions estimates and short observational periods of less than 1 minute). Paradoxically, the shorter duration measurements tend to have higher accuracy in quantification for the short duration and the longer duration measurements tend to have emission estimating uncertainties that can span orders of magnitude. The Industry Trades recommend that EPA define "credible information" in a way to allow operators to use regulatory-driven inspections, allow for additional parameter monitoring while accounting for telemetry malfunctions, site inspections or camera monitoring, and engineering estimates to determine if a release has occurred and is subject to reporting.

⁵² Underground storage station well blowout near Los Angeles, CA (i.e., Aliso Canyon) in 2015, event duration was 112 days as opposed to other events which were significantly shorter.

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3.11.5 3rd Party Event Reporting

In 98.236(y), EPA is proposing that reporters must report any events identified through a potential super-emitter release. The Industry Trades urge EPA to implement guardrails around what and how a third-party could report, which is particularly impactful for those subject to SERP. Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality and accuracy of those reports (including, but not limited to, data integrity, completeness, free from atmospheric interference, timing or greatly delayed notification, etc.). While the industry strives for excellence in reducing large release events, resources which would otherwise be utilized to minimize emissions could be diverted to respond to large volumes of unfounded third-party notifications which may have no basis in reality.

The proposed requirement to consider third-party release reports is beyond EPA's authority.

Additionally, the **Industry Trades request EPA to clearly define the scope of credible information that would trigger additional investigative and reporting burdens.** The Industry Trades are concerned that unqualified third-party reports developed by unqualified operators could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear guidelines on who would be qualified to provide third-party reports and the associated duration of an observation necessary to trigger investigation and reporting obligations under Subpart W.

EPA proposes that third-party reports of “other large release events” submitted under NSPSSubparts OOOOb or OOOOc must be documented and addressed under Subpart W.⁵³ **API explained in its comments on the Subpart OOOOb and OOOOc proposed rules that EPA does not have authority to allow third parties to generate information that triggers regulatory requirements for affected/designated facilities.**⁵⁴ We incorporate by reference those comments here. Because the proposed third-party reporting requirements under Subparts OOOOb and OOOOc are beyond EPA's authority, those requirements should not be finalized and, by extension, should not be referenced or incorporated into the Subpart W provisions addressing “other large release events.”

To begin, it is not possible to discern without further explanation from EPA who might constitute “another third party.” That ambiguity makes it impossible to devise and submit informed comments on this aspect of the proposed reporting requirement.

Having said that, it is possible that EPA intends “another third party” to mean an entity submitting information to an affected facility outside of the third-party reporting provisions established under NSPS Subparts OOOOb or OOOOc. If that is the case, this aspect of the Proposed Rule is inadequate because EPA fails to explain the legal basis for imposing such requirements, including why such a requirement might be a reasonable under CAA § 114. Such a requirement would, in any event, be outside of EPA's CAA § 114 authority because CAA § 114 authorizes only EPA to collect information. It does not authorize EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or

⁵³ 88 Fed. Reg. at 50433.

⁵⁴ API Comments on EPA's Proposed “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” EPA-HQ-OAR-2021-0317-2428 at 97-99.

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assertions. If EPA believes that information about “other large release events” not reported pursuant to NSPS Subparts OOOOb or OOOOc should be reported by affected facilities, EPA must initiate the information request and may not rely on reports submitted by third parties.

Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality (including data integrity, completeness, free from atmospheric interference, timing of or significant delay in notification, etc.) and accuracy of third-party reports. The Industry Trades may submit supplemental comments after the Oct. 2 deadline.

At this time, the term “credible” is not defined in this rule. The Industry Trades recommend that EPA adopt the Industry Trades recommendations for SERP, and 98.236(y) is modified to only include events which EPA deemed credible under the SERP, and modify the citation below as follows:

(y) Other large release events. You must indicate whether there were any ~~other~~ credible large release events from your facility during the reporting year and indicate whether your facility was notified of a ~~potential~~ credible super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any ~~other~~ credible large release events, you must report the total number of ~~other~~ large release events from your facility that occurred during the reporting year and, for each ~~other~~ credible large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

The Industry Trades are re-iterating our previously submitted comments regarding the credibility of those 3rd-parties reporting⁵⁵ as proposed in NSPS OOOOb. In short, the Industry Trades reiterate the importance that any third-party conducting these monitoring events should be certified by EPA to be included in the SERP.

In general, the Industry Trades are concerned that events reported under other source categories, such as “blowdowns,” thief hatches or equipment leaks could inadvertently be double counted under other large release events. The Industry Trades requests that EPA codify clear guidance on how to ensure that information reported by a 3rd party can be appropriately subtracted from events that could reasonably be reported under another category.

3.11.6 Other Concerns Regarding Other Large Release Events

The Industry Trades request that EPA remove the latitude/longitude reporting requirement proposed in 98.236(y)(11)(iii), and instead allow county-level reporting for pipeline release events (consistent with PHMSA requirements). If EPA maintains the requirement to report latitude and longitude of the release event, the Industry Trades request that EPA clarify that these events at sites other than pipeline locations may consist of a single latitude/longitude for a site (and should not include the granular latitude and longitude of the individual component).

⁵⁵ API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal letter, dated February 13, 2023. Section 1.1.

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Furthermore, remote sensing technologies generally do not distinguish between emissions sources that are transient, included sources (blow downs, liquid unloadings, crankcase venting, etc.), or unintended sources that may or may not already be identified (unlit flares, over pressurized tanks, etc.) and thus there is a risk for double counting of certain emissions. Owner/operators should exclude sources that are already otherwise accounted for under another category, and EPA should explicitly allow exclusion of observations that could be classified as large emissions events but are otherwise already accounted for in another category.

To address one of EPA's requests for comments in the preamble, the Industry Trades believe that reconciling top-down data with bottom-up data should not force reporters to revise bottom-up estimates. The values recorded by these top-down sensors require significant data processing and analytics to provide the required measurement values, including concentration or flux. Moreover, even if the concentration (or concentration-pathlength) were perfectly accurate, error is introduced in post processing to produce estimates of emission rates, and these errors vary greatly depending on both the technology deployed, but even proprietary data treatment techniques between vendors of similar technologies. Beyond these uncertainties, however, is an inherent uncertainty introduced due to the temporal misalignment between the observational data and the bottom-up reporting methods. Not only do "matching" style reconciliation exercises require high spatial resolution of bottom-up emissions estimates (disaggregation to sites or even to the equipment level), but such exercises demand high temporal resolution. Otherwise, reliable extrapolation techniques must be applied to the often short duration observations to produce longer term emissions estimates. The aggregation of these uncertainties implies that the "top-down" measurements cannot be deemed more accurate, but simply useful in that they provide a different view of emissions.

3.12 Reporting Combustion Sources in Subpart C versus Subpart W

Emissions from natural gas combustion are *not* waste emissions that should be subject to the methane fee but are a result of the end use of natural gas within the value chain; emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations.

The Industry Trades appreciate that EPA intends to provide clarity on when reporters can use subpart C calculation methodologies instead of Subpart W, including defining the applicable gas quality. However, EPA has not provided sufficient information to justify the composition threshold of natural gas in determining between use of Subpart C or Subpart W calculation methodologies. EPA, in the TSD-W, concluded that the appropriate threshold criteria for use of subpart C includes a natural gas composition of 85% CH₄, but this threshold does not appear to represent any national or basin-wide average of the composition of fuel gas. EPA must provide additional information regarding the election of the 85% CH₄ composition threshold as a criteria for use of Subpart C methodologies.

As the Industry Trades previously commented during the June 2022 proposal, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C to conform with the structure of the rule for other industries reported under the GHGRP. This would eliminate the current and proposed confusing structure that splits oil and gas combustion emissions across multiple subparts and references back and forth between the two subparts.

EPA seeks comment on "amending Subpart W to specify that all industry segments would be required to report their combustion emissions, including CH₄, under Subpart W to more accurately reflect the total

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CH₄ emissions from such facilities within the emissions reported under Subpart W.” EPA asserts that Section 136(h) of the CAA specifies that EPA must “revise the requirements of subpart W.... [to] accurately reflect **the total CH₄ emissions and waste emissions** from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, **to demonstrate the extent to which a charge under subsection (c) is owed**” (emphasis added). Methane slip emissions from combustion are *not* waste emissions that are subject to the methane fee but are a result of the end use of natural gas within the value chain. Therefore, such emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations, when they are defined under future EPA rulemaking.

The IRA includes several statements that clarify the definitions of waste with regards to methane emissions within the rule. The IRA includes provisions for exemptions based on regulatory compliance with new source performance standards and state-level implementation of existing source rules that are equivalent or greater in emissions reductions to EPA’s November 2021 Methane Rule framework. Neither the 2021 Methane Rule Framework nor the subsequent December 2022 proposal for NSPS OOOOb and EG OOOOc include source performance standards for methane slip from compressor engines. While not directly applicable to the methane fee, Section 50263 of the IRA clarifies that royalties on all extracted methane emissions on Federal lands and the Outer Continental Shelf have a stated exception for “gas used or consumed within the area of the lease, unit, or communitized area”, which clearly would exempt the routine use of fuel gas, and associated methane slip emissions, from such royalty calculations. Considering these statutory provisions of the IRA, methane slip from compressor engines should not be included within the emission calculation framework for Subpart W and the eventual methane fee calculations that EPA will define at a later date.

3.13 Methane Slip from Incomplete Natural Gas Combustion

Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.

The Industry Trades agree with the agency that the default combustion efficiency for incomplete combustion or "methane slip" should be updated. However, it is important to note that the changes to methane combustion slip emission factors are expected to result in one of the largest changes to reported methane emissions, and EPA should allow the use of performance tests to determine methane slip factors regardless of fuel type. This would critically incentivize investments in technologies to reduce methane slip and would meet the objective of using empirical data. However, EPA should include these revisions under Subpart C instead of under Subpart W.

EPA’s basis for exclusively using default equipment-specific destruction efficiencies, when the fuel does not meet at least 950 btu/scf, and contains less than 1% CO₂ and at least 85% methane by volume is flawed. We recognize that EPA tried to simplify the performance test requirement to a one-time performance test, and as such did not propose to allow performance testing because fuel types “are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions.” The Industry Trades make two comments on this assertion. First, operator experience indicates that field gas is not significantly variable year over year and EPA does not provide data to support its assertion. Second, EPA does not explain why the range of any expected variability would result in a change in

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combustion slip. Third, and most importantly, reporters commonly conduct performance testing on engines to meet NSPS JJJJ/NESHAP ZZZZ or state regulatory requirements. As such, EPA should allow reporters to use those results regardless of the fuel gas type, as well as the default equipment-specific combustion efficiency for reciprocating internal combustion engines (RICE) and gas turbines (GT), as long as the performance test results are only applied to sites with similar fuel gas quality.

To further emphasize the importance of allowing performance test data from any RICE or GT, the Zimmerle study cited by EPA is representative for natural gas compressor stations, but it does not include any smaller engines likely to be found in an upstream environment. Allowing directly measured data will both provide EPA with additional details regarding methane slip related to the smaller engines, and it will allow operators to use empirical data as aligned with EPA’s intent. Critically, this will also incentivize operational improvements to reduce methane slip from natural gas combustion. This also clears up the proposed discrepancy where EPA proposes to mandate incorporation of performance test results for some RICE and GTs, but prohibits the use of performance test results for others. Ultimately, there is no reason EPA should not allow operators to use results from periodic performance tests conducted per EPA reference methods regardless of fuel quality.

The table below summarizes the distribution of combustion efficiencies calculated from member-provided performance tests:

Horsepower	Count	Minimum Combustion Efficiency	Mean Combustion Efficiency	Median Combustion Efficiency	Maximum Combustion Efficiency
> 500 hp	76	96.16%	98.29%	99.46%	99.46%
< 500 hp	57	98.29%	99.58%	99.99%	99.99%

The above data is based on performance tests using engine horsepower, load, break-specific fuel consumption, the average grams of methane per horsepower-hour over three test runs, and the methane concentration of fuel gas. The combustion efficiencies were derived by dividing the stack test mass of methane by the mass of methane consumed in the fuel gas. The results show that minimum stack test combustion efficiency for engines greater than 500 horsepower is on par with EPA’s equipment-specific default combustion efficiency for 4 stroke lean burn engines; while the combustion efficiency for engines less than 500 horsepower is greater than EPA’s equipment-specific combustion efficiency for the same engine type. The data illustrates how smaller engines typically have favorable combustion efficiencies given they have smaller cylinder bores. The Industry Trades believe that allowing operators to develop horsepower-specific destruction efficiencies based on performance tests would lead to more accuracy while meeting EPA’s intent to measure combustion slip from internal combustion units.

EPA should also allow for flexibility to incorporate methane controls as new technologies are being developed to control methane emissions from RICE. The Industry Trades recommend that EPA add a methane control efficiency parameter to Equation W-39B to allow for flexibility of incorporating a control efficiency to enable reporters to report methane slip more accurately when methane control technologies emerge and are demonstrated to be effective.

Allowing for the use of additional approaches to calculate methane slip from compressor engines would further support technology development. For example, the Department of Energy is currently in year

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two of funding for the ARPA-E REMEDY program ([REMEDY | arpa-e.energy.gov](https://arpa-e.energy.gov)) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in natural gas fired lean burn engines. If technology development from this 3-year, \$35 million research program is successful, the ability to use updated values in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.14 Drilling Mud Degassing

In proposed Calculation Method 1, EPA is proposing to quantify drilling mud degassing by applying an emission rate derived from a representative well in the same sub-basin and at the “same approximate total depth.” The Industry Trades request clarification on how to determine the “same approximate total depth.”

EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The Industry Trades disagree with this requirement, as it is possible a mudlogging measure is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The Industry Trades recommend allowing reporters to use Methodology 2 for all active drilling. The Industry Trades also propose a third option (see next comment), in the event that some mudlogging data is available.

The proposed third option would serve as a combination of the currently proposed Method 1 and 2. As stated above, this would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. In this third option, mudlogging measurements would be used based on Method 1 for the period in which the data is available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data is not available. This method should also allow operators to account for drilling mud degassing vapors sent to a control device.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the representative well. The Industry Trades request that EPA clarify that this should be calculated based on circulating time in the hydrocarbon bearing zones only (i.e., excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

One further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

3.14.1 Proposed Calculation Method 2

EPA is proposing the following emission factors in MT CH₄ per drilling day for drilling mud degassing: 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds. The EPA based these factors on a study evaluating emissions from offshore drilling from 1977, which is both outdated, and not representative of most onshore drilling operations in the United States. Furthermore, these outdated factors are based on mud throughput, but the basis remains unclear. The Industry Trades reiterate that the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing (Section 6.2) is appropriate for the well bore and porosity conditions for onshore drilling operations as it was developed specifically for onshore operations. Use of the proposed offshore emission factors for onshore drilling operations will significantly overstate methane emissions

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from onshore production mud degassing. The Industry Trades suggest that the emission factor should be derived as a function of well dimensions to better represent mud degassing emissions. Otherwise, the Industry Trades recommends that proposed methodology 2 be revised based on drilling time in hydrocarbon hole section, and not overall event days. There can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

3.14.2 Reporting Requirements

Reporting requirements proposed in 98.236(dd) require reporting total vertical depth of the well, and the circulation time of the drilling mud within the wellbore. The Industry Trades do not support reporting this information, as EPA did not address why the information would be requested. Furthermore, total vertical depth would not provide representative information for horizontal wells and would not improve the reported data quality.

3.15 Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades believe the emission factor for this activity should be derived based on horsepower in order to be more reflective of operations in the onshore production or gathering and boosting segments, should include the ability to take credit for routing the emissions to a control device, and do not believe this emission source category should include gas turbines. The study cited in the TSD included an audit of three gas compressor stations and two natural gas storage sites⁵⁶. These facilities are expected to have a much higher vent rate than in production operations due to the larger engine size required in gas compressor stations and gas storage. Therefore, the proposed average emission factor may reflect an overestimation of this source for upstream production and many smaller gathering and boosting facilities. The Industry Trades suggest that EPA considers deriving an emission factor based on engine horsepower instead of vent count, as the vent rate is correlated with engine size rather than number of vents.

As proposed, there is no method to reflect reductions if emission controls are developed and implemented or crankcase venting is routed to a control or combustion device. The Industry Trades recommend adding this flexibility by including a control efficiency parameter in Equation W-45, which also has the added impact of incentivizing controls where feasible.

The Industry Trades also recommend that EPA provide clarification around how to account for crankcase vents which are manifolded together, as the reporting requirements are on a per-vent basis.

EPA is proposing a reporting requirement for the average operating hours for each reciprocating internal combustion engine or gas turbine. The Industry Trades recommend the removal of this “average” data; it is duplicative and requires operators to average numbers used in calculations for the sole purpose of reporting this element. The Industry Trades recommend removing this data reporting requirement or leaving the reporting requirement on a per-site basis of total operating hours.

⁵⁶ Johnson *et al.*, 2015

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Additionally, the factor prescribed by EPA is based on an API study,⁵⁷ which only represents reciprocating engines, and not natural gas turbines. The study's definition of crank case is, "The crank case on *reciprocating engines* and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft..."⁵⁸ (emphasis added). The study also only referred to reciprocating engines later in the document, "Additionally, *reciprocating engines* crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions⁵⁹" (emphasis added). There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

Natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature - the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

⁵⁷ Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf and in the docket for this rulemaking, Docket Id. No. EPA-HQ-OAR-2023-0234.

⁵⁸ Page 14 of 74 of API study.

⁵⁹ Page 40 of 74 of API study.

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The Industry Trades propose that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines.

3.16 Gathering and Boosting versus Production Site Categorization

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites." These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

The Trades appreciate that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and environmental disincentives with including "centralized oil production sites" in the gathering and boosting segment, especially when viewed through the lens of the upcoming waste emissions charge.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment. These sites perform many of the same functions as the traditional well pad only production facilities (which are included in production), but reduce the overall environmental footprint associated with oil and gas development included emissions reductions and minimizing surface use by flowing multiple wells into on pad.

Next, EPA's proposed definitions are contrary to IRA's MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production." In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production." The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production." Clearly Congress did not intend for sites associated with production, such as "centralized production sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators.

EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, *see* 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id.* § 136(f)(1), (2)

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources.

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In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, increasing GHG emissions, and increasing surface use.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to “production supportive facilities.” Many operators have migrated to more centralized production facilities in an effort to reduce the overall environmental footprint. As opposed to midstream operators that traditionally operate gathering and boosting sites downstream of a custody transfer meter that are typically large compressor stations that boost gas across an area, the sites in question are a less impactful way of separating and storing fluids from multiple wells and providing efficient compression for artificial lift. Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as “associated with a single well pad” this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners / operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the “centralized oil production facilities” (referred to in NSPS OOOOb as “centralized production facilities”) are grouped under the production segment by definition, not gathering and boosting as explained below:

Currently, in Subpart W “Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236.”

While NSPS OOOOb/c has a different name and definition of this as follows:

“Centralized production facility” means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage

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vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.”

In addition, in the Pipeline and Hazardous Material Safety Administration’s (‘PHMSA’) proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as “gathering and boosting.” Specifically, as defined in API’s Recommended Practice-80 and incorporated in 49 CFR 192:

“The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. ‘Production Operation’ means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply.”

Both the NSPS OOOOb/c and PHMSA’s name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. To mitigate confusion and create more rule alignment, the Industry Trades suggest that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal,

“as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs.” Also, the Trades note that even though EPA uses the word “gather” in the definition in Quad Ob/c, these sites are still properly defined as “part of the producing operations.”

Further, the fact that EPA has proposed the definition of “centralized production sites” as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA possibly does not understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, The Industry Trades request that EPA change both the name and definition of “centralized oil production site” in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production (not gathering and boosting) for consistency and to reflect how the industry owns and operates these facilities. The Trades also strongly recommend that EPA delete “associated with a single well pad” from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

3.17 [Need for EPA to Include Pathways for Other Types of Empirical Data](#)

For many source categories under Subpart W, the Trade Industries appreciate that EPA has included several options for operators to be able to provide empirical data, such as measurement with metering

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or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. As API shared with EPA during the NSPS OOOOb and OOOOc rulemaking, many operators have included these technologies in their voluntary methane management programs, including the use of quantitative aerial technologies at more than 8,000 sites. Many of these systems provide quantitative information that, when paired with other operational sources of data, provide empirical information about methane emissions from assets. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. **A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.**

4. Administrative Recommendations

4.1 Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

1. EPA should provide industry with a draft of the eGGRT form for review ahead of the reporting season (prior to January 1, 2026). The Industry Trades are concerned that the site-by-site reporting could cause these files to become very large and difficult to transmit and/or store.
2. EPA has not indicated how Best Available Monitoring Methods (BAMM) will be allowed for the newly proposed sources. The Industry Trades reiterates the need for ample implementation time.
3. Remove all requirements to report a count of equipment or events when there is a requirement to report on an equipment- or site-level basis. Requiring a count of an item that is already provided on a line-by-line basis does not improve the reported data quality, does not increase EPA's ability to validate the reported data, and introduces potential errors that will flag unnecessary follow between reporters and EPA.
4. Remove or automate Table AA.1.ii on Tab (aa)(1). All the required information is reported in Table AA.1.iii. By repeating this information in Table AA.1.iii, it increases the possibility of data errors while not improving data transparency.
5. Remove detailed reporting elements on Tab (aa)(1) in Table A.1.iii, as the detailed information on a well-by-well basis is already included on the respective source tabs (and proposed additional sources as part of this rulemaking):
 - a. Well venting for liquids unloading;
 - b. Completions or workovers with hydraulic fracturing;
 - c. Completions or workovers without hydraulic fracturing;

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- d. Well testing; and
 - e. Associated gas venting and flaring.
6. Miscellaneous Topics
- a. Reporting condensate separate from other hydrocarbon products will be challenging due to where and how it is separated.

5. Rule Implementation

EPA's plans to finalize the rule in August 2024, with an implementation date of January 1st, 2025. The impractical tight timeframe to implement the final rule places an unrealistic expectation on reporters, especially given that (as proposed) they will have to install new equipment and develop inspection programs to comply with the rule. The impracticality of the proposed timeline is further exacerbated by the persistent supply chain shortages operators are experiencing for critical equipment necessary to comply with the proposed NSPS OOOOb, as the Industry Trades have described to EPA.⁶⁰ Primarily, the Industry Trades reiterates its position that measurement, sampling and monitoring requirements should not be included in the GHGRP itself. However, should any measurement, sampling and monitoring requirements be codified in Subpart W for sources not required to comply with other regulatory programs, EPA should allow for a phase-in period (as it did during the first two years of Subpart W implementation) to allow for reporters to incorporate those requirements.

6. Conclusion

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed measurement, reporting, recordkeeping, and quality assurance/quality control requirements.

The Industry Trades support the goal of reducing GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter. We stand ready to respond to any questions and provide further clarifications, as needed, from EPA. Please do not hesitate to contact any of the undersigned or API's Jose Godoy, Climate & ESG Policy Advisor, at godoyj@api.org.

Sincerely,

⁶⁰ <https://www.api.org/news-policy-and-issues/letters-or-comments/2023/09/20/API-Letter-to-EPA-Administrator-Regan-on-EPA-Methane-Rule>.

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ANNEX A: API Study, “Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States.

Note: Data for this study is included separately within this docket in excel format.

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ANNEX B: API Comments on Proposed Subpart W, Submitted July 21,
2023

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ANNEX C: API Comments on EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023

Docket ID No. EPA-HQ-OAR-2023-0234
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ANNEX D: API Barnett and Bakken Mantis Field Studies

Docket ID No. EPA-HQ-OAR-2023-0234

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ANNEX E: Supply Chain Study Results Letter, Submitted September 19,
2023

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ANNEX F: API Assessment of Properly Functioning and Malfunctioning Intermittent Bleed Pneumatic Controllers

Note: Data for this analysis is included separately within this docket in pdf format