July 15, 2024

Submitted Electronically

The Honorable Michael S. Regan, Administrator
U.S Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Climate Change Division, Office of Atmospheric Programs (MC-6207A), Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Docket No. EPA-HQ-OAR-2023-0234

Dear Administrator Regan:

The American Petroleum Institute (API) and the American Exploration & Production Council (AXPC) (collectively "Industry Trades") hereby submit this petition for changes to the Final Rule entitled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (89 FR 42062, May 14, 2024) due to the immediate infeasibility and accuracy concerns related to data collection and accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry.

The Industry Trades recognize the Environmental Protection Agency's (EPA's) significant efforts to finalize this highly complex and technical rule and support its aim of increased accuracy and transparency in emissions reporting. However, several critical issues remain that must be addressed and revised as they do not improve the accuracy of GHG emissions reporting, provide transparency, nor reflect realities of the industry and its evolving operating practices. Accurately reporting GHG emissions and continually improving the accuracy of GHG reporting are both common objectives of the EPA and our industry, and we look forward to continuing constructive engagement with EPA on the Final Rule.

API and AXPC jointly submit this petition for convenience and efficiency. API and AXPC each respectively reserve their individual rights in submitting this request.

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 Greenhouse Gas Reporting Program (GHGRP). API has worked with both EPA and industry for more than two decades to develop methodologies for estimating GHG 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 GHG emissions are continually evolving.

AXPC is a national trade association representing 33 leading 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, their 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.

Thank you for your prompt consideration of this request. We look forward to continuing constructive engagement with EPA to ensure the Final Rule is cost-effective, technically feasible, and accomplishes our shared goal of accurate emissions accounting. Please do not hesitate to contact us or API’s Jose Godoy (Godoyj@api.org) if you or your staff have any questions.

Sincerely,

Aaron Padilla
Vice President, Corporate Policy
American Petroleum Institute

Wendy Kirchoff
Senior Vice President of Policy
American Exploration & Production Council

EXECUTIVE SUMMARY

The Industry Trades support the inclusion of empirical data and increased attention on improving data accuracy in the EPA's Final Amendments of Subpart W (Final Rule) of the GHGRP codified at 40 C.F.R. Part 98 (89 Fed. Reg. 42062, May 14, 2024). Several issues remain within the Final Rule that require further attention.

Allowance for the use of empirical data is particularly important across Subpart W emissions sources given that reported emissions will form the basis of assessed methane fees pursuant to the Waste Emissions Charge (WEC) implemented under the Inflation Reduction Act (IRA). As such, the requested changes described below may prevent a potentially significant financial impact on the Industry Trades' membership as a result of inaccurate emissions reporting requirements. Therefore, the Industry Trades request immediate changes to the provisions listed herein to address inaccurate and impractical compliance and reporting obligations.

The Industry Trades' highest areas of concern with the Final Amendments of Subpart W are the following:

- **Flare stacks.** The tiers for destruction efficiency in the Final Rule should be revised in recognition of relevant data and the difference between upstream and downstream operations. For flare stack emission calculations, the three tiers of default destruction and combustion efficiencies in the Final Rule do not properly factor in all available empirical data. In addition, the top tier relies on complying with requirements that are specific to petroleum refineries, which is flawed considering those requirements are technically inappropriate for flares in upstream operations. Refer to Comment I.
- **Other large release events (OLRE)**. The finalized provisions for OLRE create an undue administrative burden that does not increase accuracy and may lead to confusion and reporting errors. EPA must simplify the methodology to focus OLRE on sources not reported elsewhere per § 98.233. At a minimum, there are numerous clarifications required if named sources are retained to increase clarity to reporters. Refer to Comment II.
- **Combustion emissions.** The Final Rule retains reporting emissions from stationary combustion sources for certain industry segments under Subpart W, inappropriately linking these emissions to the WEC. Emissions derived from the combustion of fuel are not "waste" and should be excluded from methane fee calculations. EPA can transparently make this change by moving all combustion from petroleum and natural gas systems to Subpart C, which is the subpart codified for emissions from stationary combustion sources. EPA's only justification for retaining combustion for certain segments under Subpart W is centered on the composition of gas (i.e., pipeline quality gas versus process or fuel gas). We note that methodologies to calculate various fuel compositions could be moved to Subpart C and applied to all industries that may combust process gas. Refer to Comment III.

The Industry Trades are committed to working with EPA to make sensible changes to the rule that further improve accuracy in GHG emissions quantified and reported, while also reducing the administrative reporting burden for reporters.

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While the Industry Trades understand the time constraints under which this rulemaking occurred, the Final Rule does not fully implement the directives of Clean Air Act (CAA) Section § 136(h) to revise Subpart W to allow for the use of empirical data in greenhouse gas (GHG) emissions. The following overarching issues were identified in the Final Rule that appear in many of our comments on the various source categories.

- The Greenhouse Gas Reporting Rule (GHGRP) is a reporting rule and should allow best available monitoring data by allowing the use of empirical data consistently across emission sources. The use of empirical data for estimating emissions is paramount.
- As a framework for quantifying and reporting emissions, Subpart W should provide emission estimation methods and incorporate existing compliance programs that are applicable to the oil and natural gas industry segments defined in § 98.230 to inform source category calculation methodologies. EPA is inappropriately incorporating reference to regulations that are not applicable to industry segments reporting under Subpart W (e.g., NESHAP CC). These requirements are not suitable for inclusion in this rulemaking and should not exceed that of the EPA's New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review ("Methane Rule" or "NSPS OOOOb/c"), which EPA develops based on specific criteria for identifying cost-effective measures that are appropriate for the industry segment.

Since the Final Rule has two sets of revisions; one set effective July 15, 2024, for Reporting Year (RY) 2024, and another set effective January 1, 2025, for RY 2025, our comments are intended to apply to one or both sets of revisions, as applicable.

I. Flare Stacks

The Final Rule has three tiers of destruction and combustion efficiencies for flare emission calculations [§ 98.233(n)]. These tiers are based on the flawed application of refinery requirements to upstream and midstream operations, ignored available data, and improperly applied study data. The flare tiers should be revised as follows:

1) The Tier 1 references to NESHAP CC should be removed since refinery requirements are operationally infeasible and economically unreasonable to implement for upstream flares.
2) The Tier 2 destruction efficiency should be revised to 98% based on data submitted during the comment period and should apply to flares that follow NSPS OOOOb/c.

3) The Tier 3 destruction efficiency should be revised to 95% based on the complete results from the Plant et al. study.

Furthermore, **operators should be allowed to determine a destruction or combustion efficiency above Tier 1 (e.g., greater than 98%) using performance testing with standard or alternative test methods**. All together, these revisions to the flare requirements would be more aligned with the directives in CAA § 136(h) that reported emissions be based on empirical data. Appropriate flare efficiency is an important issue that industry is prioritizing and fully supporting to ensure accurate emission reporting.

1. The Tier 1 efficiency references NESHAP CC, an emission standard applying to petroleum refineries, which is operationally and economically infeasible to implement for upstream flares. NESHAP CC should be removed from the tiered approach for flare efficiencies under Subpart W.

Tier 1 efficiency requirements for flares are especially problematic since they reference testing and monitoring regulations for flares subject to National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR Part 63, Subpart CC) (NESHAP CC). These requirements are technically infeasible and economically unreasonable to implement for flares in upstream and midstream operations; therefore, NESHAP CC must be removed from the tiered default destruction and combustion efficiencies for flares.

The provisions outlined in Tier 1 are based on the presumption that flares being used at a petroleum refinery would operate under the same conditions as those found in upstream oil and gas operations. Industry Trades explained in our respective comments[1] submitted October 2, 2023, on the proposed rule that such a presumption is invalid. API's comments also included testing data from over 100 flares that demonstrated mean and median destruction efficiencies of more than 98% (see pages 35-36 and Annex D). None of these flares were subject to NESHAP CC requirements, which strongly suggests compliance with NESHAP CC is not a prerequisite to achieving +98% destruction efficiency (DRE).

On page 522 of EPA's Response to Comment, EPA reiterated the incorrect premise that *"the proper operation of a flare is not sector dependent."* This presumption is categorically false as a flare or other control device must be designed and operated based on site process conditions including the flow streams and compositions it is designed to control. As such, upstream and downstream flares vary widely in design and operation as summarized in Table 1.

As Table 1 describes, the design conditions that drive compliance assurance requirements of NESHAP CC simply do not exist in the upstream industry segment making the application of those monitoring requirements inappropriate and unnecessary. As a reporting rule, Subpart W should not force upstream flares to comply with inappropriate refinery requirements from NESHAP CC to

[1] https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0234-0402; https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0234-0295.

claim a 98% destruction efficiency for reporting emissions, as testing routinely shows flares meet +98% destruction efficiency without complying with NESHAP CC. Upstream flares should comply with regulations designed for the upstream industry segment, such as the New Source Performance Standards for Crude Oil and Natural Gas Facilities or air permit conditions that reference 40 CFR § 60.18. These upstream-specific regulations adequately and appropriately address proper flare operation to claim a 98% destruction efficiency as discussed below in more detail.

Table 1. Comparison of Relevant Characteristics of Upstream versus Petroleum Refinery Flares

Parameter	Upstream/Midstream Operations	Refinery Operations	*Why it matters?*
Staffing and Flare Count	• Upstream sites are not staffed 24 hours per day, nor are many midstream sites. • Upstream and midstream operations consist of hundreds of thousands of geographically dispersed flares, many located in remote locations.	• Refineries are staffed all hours of the day, every day. • A typical large refinery has fewer than twenty flares, all located at the facility.	• *The refinery flare provisions are onerous and require significant monitoring and personnel resources for compliance. These personnel and resources are available on site at a refinery.* • *Maintaining the monitoring equipment alone requires significant human resources for a single refinery.*
Flow Rate	• Intermittent flows from storage tanks, liquids unloading operations, associated gas, and certain controllers and pumps cause vapor flows to vary from zero to very high rates and vice-versa in a short space of time. • Flare gas recovery and compression systems are typically not installed due to limited infrastructure and secondary markets to distribute recovered gas in remote locations. • Upstream flare flows can be reliably quantified using engineering calculations.	• Process gas flows from multiple process units are typically routed to flare gas recovery and compression to minimize the quantity of gas flared.	• *Upstream flare flows can be reliably quantified using engineering calculations.*
Gas composition	• Upstream and midstream operations have highly variable, intermittent flow rates to flares, with limited variability of gas compositions. • There is a small number of streams routed to flare (often only one stream), and the composition of each stream is relatively consistent over time. For example, a well pad site often has two flares, one for handling low-pressure streams like tank	• Potentially hundreds of unique process streams are routed to a refinery flare header. • Composition of refinery streams is highly variable. • Crude oil feedstocks are processed through multiple units to derive multiple products and intermediates. • Refineries routinely use inerts in their processes (e.g., clearing equipment	• *Applying refinery flare vent gas composition monitoring is unnecessary in the midstream/upstream context because the vent gas stream composition is relatively constant.*

Parameter	Upstream/Midstream Operations	Refinery Operations	*Why it matters?*
	vapors and another for handling any higher pressure streams. • The composition of the producing zone remains relatively constant over time. • Upstream operations perform physical separations, not multiple chemical processing steps. • There are limited scenarios in Upstream operations where inert gases are added to the process (for example, enhanced oil recovery and amine treating). • Please review the sample NHV data showing the limited variability of composition in Appendix 1.	for service, tank blanketing, etc.) which is reflected in the flare gas composition.	
Pilot	• Automatic ignition systems to initiate combustion in the flame zone (e.g., electronic spark ignition) are common in upstream applications. • Natural gas or refinery fuel gas is not readily available in upstream to supply constant pilot flame. • Reducing the unnecessary continuous combustion of pilot gas is an environmental benefit. • While many upstream and midstream flares will have continuous burning pilots necessitated by NSPS OOOOb and EG OOOOc compliance, many will not, especially lower emitting sources that will not be subject to either rule.	• Multiple refinery regulations require the constant presence of a pilot flame to demonstrate compliance, resulting in increased GHG emissions. • Natural gas or refinery fuel gas is readily available to supply constant pilot flame needed for standard, constant flow to flare.	• *Continuous burning pilot is an emissions source that can be eliminated effectively by installing automatic ignitors. Further automatic ignitors are less prone to be affected by high winds and inclement weather. For these reasons, a separate regulatory requirement should not mandate a continuous burning pilot, nor should operators be required to install and operate one.*

2. The Tier 2 destruction efficiency should be revised to 98% based on datasets submitted during the comment period. Tier 2 should apply to flares that comply with NSPS OOOOb, EG OOOOc, or a legally and practicably enforceable permit.[2]

The Final Rule retains a Tier 2 destruction efficiency of 95% that applies to flares (including enclosed combustion devices based on EPA's definition of flare under Subpart W) that comply with NSPS OOOOb or EG OOOOc. NSPS OOOOb and EG OOOOc establish a *minimum* destruction efficiency. Using the minimum 95% control standard for this tier is inappropriate as it would overestimate actual methane emissions from flare stacks reported under Subpart W.

During the comment period, additional data were submitted for EPA consideration in evaluating the proposed Tiers. API submitted testing data from over 100 flares that demonstrated mean and median destruction efficiencies of more than 98%.[3] EPA also did not consider performance test data submitted by manufacturers or operators pursuant to compliance with NSPS OOOOa that also establish destruction efficiencies above 95%. EPA simply failed to adequately consider all relevant and valid empirical data. Numerous states, such as Texas, New Mexico, and Oklahoma, have permit requirements and/or guidance on proper control device operation.[4,5,6,7] Some of these state permitting programs refer to 40 CFR § 60.18 for proper flare operation. Flares designed and operated according to 40 CFR § 60.18 specifications have also been tested and shown to achieve a minimum of 98% destruction efficiency. While EPA considers 40 CFR § 60.18 to be inadequate for 98% destruction efficiency for flares at petroleum refineries (e.g., over-assisting the flare lowered destruction efficiency), these issues do not exist at the typical upstream flare based on the operating conditions summarized in Table 1 (i.e., assisted flares are less common).

We reiterate that flares in upstream operations should be subject to regulations designed for the upstream industry segment, such as the NSPS OOOOb/c or air permit conditions that reference 40 CFR § 60.18. These upstream-specific regulations adequately and appropriately address proper flare operation to claim a 98% destruction efficiency. We note the testing data previously submitted by API contained flares that operate under existing requirements (see Comment 3), and implementation of NSPS OOOOb and EG OOOOc will only enhance these results making the application of 95% DRE for these flares illogical. **Therefore, flares following the requirements**

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[2] Including an approved state plan or applicable Federal plan in part 62 of this chapter.
[3] https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0234-0402. *See* pages 35-36 and Annex D of comments.
[4] Texas permit requirements found at 30 TAC §§ 106.352(e)(11), 106.352(m) – Table 8, 106.492, 116.620(a)(12), and Air Quality Standard Permit for Oil and Gas Handling and Production Facilities – paragraph (e)(11) and Table 8 (https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf).
[5] Oklahoma Air Quality General Permit to Construct/Operate Oil & Gas Facilities – Appendix A (https://www.deq.ok.gov/wp-content/uploads/air-division/GP_oil_and_gas_facilities_permit.pdf).
[6] New Mexico Air Quality Bureau General Construction Permit for Oil and Gas Facilities – Section A207 (https://www.env.nm.gov/wp-content/uploads/sites/2/2018/06/GCP-Oil-Gas-Final-002.pdf).
[7] Texas Commission on Environmental Quality (TCEQ). Control Device Requirements Charts for Oil and Gas Handling and Production Facilities.
https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf

specified in NSPS OOOOb, EG OOOOc[8] or a legally and practicably enforceable state permit (including references to 40 CFR § 60.18) are appropriate and sufficient to support a revised Tier 2 destruction efficiency of 98%.

3. The Tier 3 efficiency was based on a sample of results from an inadequate analysis of a research-based study that was not designed to include the needed rigor for policy development, and EPA ignored other publicly available information and data. At a minimum, the Tier 3 destruction efficiency should be updated to 95%, which is consistent with the outcomes of the same study's complete dataset.

The Final Rule has a Tier 3 default destruction efficiency of 92% based on the mean observed flare DRE for the Permian Basin from the Plant et al study.[9] The Proposed Rule did not clearly explain the basis for the 92% DRE but simply stated: *"[t]his value is based on the low end of the range of empirical results observed in testing over an extensive area in three of the most active basins in the United States (U.S.) in Plant et al."*[10] Only in the Final Rule, did EPA clarify the basis:

> *"However, the 92 percent destruction efficiency for Tier 3 is based on the mean observed flare DRE for the Permian basin rounded up from 91.7 percent to 92 percent; it is not based on the reported overall average total effective DRE of 91.1 percent... We have determined that the average observed destruction efficiency of 92 percent is a reasonable combustion efficiency for Subpart W sources that are not monitoring as specified under Tier 1 or Tier 2 because the overall average in the empirical results likely included many facilities with higher performing flares that would likely comply with one of those tiers and thus should be excluded from the calculation of the average for Tier 3 flares."*[11]

By obfuscating the basis for the Tier 3 DRE, EPA did not clearly explain a key aspect of the Proposed Rule and therefore did not allow for proper notice and comment. At the very least, the average flare DRE of 95% across all three major basins (as previously claimed by EPA) in the study should be used for Tier 3.

EPA selected a subset of the data from a research paper that was only looking at a subset of flares, chose the data from one basin instead of the average from all three, and ignored other published datasets around flare efficiency without explanation. The Permian Basin was arbitrarily selected to represent a nationwide default Tier 3 efficiency based on the incorrect assumption that the other two basins in the study (Bakken and Eagle Ford) would have more flares that would meet either Tier 1 or 2 requirements. EPA did not explain why flares in Bakken or Eagle Ford would operate differently than those in Permian Basin, and the study did not have information on monitoring associated with any of the observed flares. EPA's selection of certain data to determine these Tiers is arbitrary and capricious.

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[8] 40 CFR part 60, subparts OOOOb and OOOOc.
[9] Plant et al., Science 377, 1566–1571 (2022).
[10] 88 FR 50334.
[11] 89 FR 42146.

As noted above, it is operationally and economically infeasible for flares in the upstream industry segment to comply with NESHAP CC, so no flares would have been included in the study that follows Tier 1. Furthermore, at the time of the study publication (September 2022), the Supplemental Proposal for NSPS OOOOb/c had not been published, so the specific regulatory language for flare monitoring requirements in NSPS OOOOb/c were unknown. Industry has also submitted extensive comments on issues with the NSPS OOOOb/c flare and control device monitoring requirements; therefore, Tier 2 flares were not included in the Plant et al. dataset. Rather, at the time of the study (flights were stated to occur in 2020 and 2021), the flares in these regions were subject to the monitoring requirements under applicable state permitting programs as summarized in Table 2. These requirements largely reference procedures in § 60.18 and allow the use of auto igniters. When reviewing the results of the Plant et al. study, flares in these regions following the requirements noted in Table 2 still achieved 95% DRE on average as shown in Figure 1.

Table 2: Summary of Applicable Flare Monitoring Requirements at the Time of Plant et al. Study

State	Basin(s)	Summary of Flare Monitoring Requirements	Citation(s)
North Dakota	Bakken	Flare must meet the requirements of 40 CFR § 60.18 requirements for visible emissions, minimum NHV, maximum tip velocity, and pilot flame monitoring. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. Daily checks by an operator to verify the existence of a visible flame or to verify proper operation of the igniter may be used in lieu of a physical device. A minimum of a visual check of a flare for opacity should be done whenever an operator is on site. For flares in the High Efficiency Program, follow the monitoring requirements for the device outlined in the approval memos.	NDDH, Division of Air Quality, Bakken Pool Oil and Gas Production Facilities, Air Pollution Control Permitting & Compliance Guidance[12] NDEQ, High Efficiency Program[13]
Texas	Eagle Ford, Permian	Flare must meet 40 CFR § 60.18 requirements for minimum NHV, maximum tip velocity, and pilot flame monitoring. Flare must be equipped with a continuous pilot monitored continuously by a thermocouple or an infrared monitor or with an automatic ignition system that ensures ignition when waste gas is present. Monitors must be accurate and calibrated at a frequency in accordance with manufacturer specifications.	30 TAC §§ 106.352(e)(11), 106.352(m) – Table 8, 106.492, 116.620(a)(12), and Air Quality Standard Permit for Oil and Gas Handling and Production Facilities[14] – paragraph (e)(11) and Table 8; TCEQ Control Device Requirements Charts for Oil and Gas Handling and Production Facilities[15]

[12] https://deq.nd.gov/publications/AQ/policy/PC/20110502_OilGas_Permitting_Guidance.pdf
[13] https://deq.nd.gov/AQ/oilgas/HighEffProgram.aspx
[14] https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf
[15] https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf

State	Basin(s)	Summary of Flare Monitoring Requirements	Citation(s)
New Mexico	Permian	For flares with a continuous pilot or an auto igniter, the presence of a flare pilot flame shall be continuously monitored using a thermocouple equipped with a continuous recorder and alarm, or any other equivalent device. For manually ignited flares, the presence of a flame shall be monitored using visual observation during each flaring event. Flow monitoring using a gas flow meter and flow totalizer is required for high pressure flaring; monitoring for low pressure flaring is satisfied by the parametric monitoring of the equipment controlled by the flare. For all high-pressure flares, the flow meter, totalizer, and if used, the inline monitor shall be operated, calibrated, and maintained as specified by the manufacturer or equivalent. Method 22 observations must be conducted if any visible emissions are observed. An annual gas analysis must measure the H_2S content, VOC content, and NHV of gas being sent to the flare.	New Mexico Air Quality Bureau General Construction Permit for Oil and Gas Facilities[16] – Section A207

Figure 1. Excerpt of the Study Results from Plant et al.

Table 1. Basin-level flare effective CH_4 destruction removal efficiency.

Region	Observed flare DRE		Unlit flares (%)	Total effective DRE*	
	Mean (%)	95% CI		Mean (%)	95% CI
Eagle Ford	96.5	95.4, 97.4	4.1†	92.4	91.3, 93.3
Bakken	97.3	96.9, 97.6	3.2	94.1	93.7, 94.4
Permian	91.7	90.5, 92.8	4.9	86.8	85.6, 87.9
Average	95.2	94.3, 95.9	4.1	91.1	90.2, 91.8

*Combines observed unlit flare statistics and DRE of lit flares work) and Permian surveys [Lyon *et al.* (*33*)]

†Average of unlit flare rate observed in the Bakken (this

[16] https://www.env.nm.gov/wp-content/uploads/sites/2/2018/06/GCP-Oil-Gas-Final-002.pdf

Lastly, the study did not have the statistical and scientific rigor to support significant regulatory actions. Specifically, some major issues with the study are as follows:

- The methodology used by the authors to estimate flared gas volume has bias and a large uncertainty. Specifically, Plant et al. used Visible Infrared Imaging Radiometer Suite (VIIRS) as part of their selection criteria for flares and the methodology to estimate flared gas volume. VIIRS does not measure methane concentrations, but rather temperature and radiant heat from flares at a resolution of 750m. VIIRS is only able to collect data on flares that are detectable from space (i.e. flares with larger flow rates and larger flame size). These larger flares would not be representative of all flares in the upstream industry segment as noted in Table 1. Furthermore, the dwell time of VIIRS on a flaring site is a fraction of a second. This temporal sampling has the potential to decrease the accuracy of flared gas estimates for upstream flares with variable flow and flared gas volumes as noted by Elvidge et al.[17] The authors of Plant et al. study point out approximately 50% uncertainty of flared gas volumes with a 95% confidence. The only study used to discuss and contextualize this level of bias is from Brandt et al.[18] Another study that looked at flares located offshore and explicitly notes; *"We cannot comment, based on these results, on the accuracy of land-based flaring estimates, as the physics of observation may differ between land and ocean-based observations."*
- The study does not include enclosed combustion devices or thermal oxidizers, which are also included in the definition of flare under Subpart W. It is inappropriate to apply data specific to open tip flares visible from space to enclosed combustors and thermal oxidizers as these are fundamentally different types of equipment.
- The authors assumed lit flares corresponded to detected CO_2 and CH_4 emissions and unlit flares to only detected CH_4 emissions. This simplistic approach could have incorrectly attributed other emission sources to the flares, such as blowdowns that would have registered as methane when the site was being surveyed.
- EPA elected to use a detection and statistical methodology based solely on one particular study, and the methodology is not even allowed by EPA for operator use in their own measured and reported inventories.

Given the many issues with the use of Plant et al. study, EPA's claim that they based Tier 3 on the Plant et al. data from all three basins in the original rule proposal, and the presence of other available data on flare performance, EPA should, at a minimum, revise the Tier 3 destruction efficiency to 95%.

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[17] Elvidge, C.D.; Zhizhin, M.; Baugh, K.; Hsu, F.-C.; Ghosh, T. Methods for Global Survey of Natural Gas Flaring from Visible Infrared Imaging Radiometer Suite Data. *Energies* **2016**, *9*, 14. https://doi.org/10.3390/en9010014

[18] Adam R Brandt 2020 Environ. Res. Commun. 2 051006

4. EPA should allow both standard and alternative test methods to prove a destruction or combustion efficiency for flares above Tier 1.

The Final Rule allows directly measured combustion efficiency to be used for flares instead of the default tiers only in the case of an approved alternative test method and associated monitoring [§ 98.233(n)(v)]. The alternative test method must directly measure combustion efficiency rather than net heating value or other measurement of proper flare operation.

For flare emission calculations, EPA should allow directly measured combustion and/or destruction efficiency based on any approved standard or alternative test methods with appropriate monitoring requirements as discussed above. EPA has unreasonably limited the conditions under which a DRE above 98% may be used. Operators should be able to use a DRE above 98% (or a combustion efficiency above 96.5%) based on a performance test using a standard or alternative test method coupled with appropriate monitoring requirements to assure proper flare operation. Allowing the use of directly measured combustion or destruction efficiency would be more aligned with the directives in CAA § 136(h) that reported emissions be based on empirical data.

5. The alternative test methods in § 98.233(n)(1)(iv) should be expanded to include EPA OTM-56 to allow for more flexibility.

The Final Rule lists EPA OTM-52 as an alternative test method for flares in § 98.233(n)(1)(iv) and allows other alternative test methods approved in accordance with § 60.5412b(d) or applicable approved state or federal plan for EG OOOOc. The alternative test methods should be expanded to include EPA OTM-56 for additional flexibility in demonstrating higher combustion efficiency. The inclusion of EPA OTM-56 with appropriate monitoring requirements would provide an immediate option for operators rather than waiting for alternative test method approval under NSPS OOOOb/c.

6. The pilot flame monitoring requirements should be amended from “once every five minutes” to “once every hour” given the technical difficulty to utilize vast datasets for reporting.

Starting with RY 2025, the Final Rule requires continuous monitoring for a pilot or combustion flame at least once every five minutes [§ 98.233(n)(2)(i)] for Tier 1 or 2 destruction efficiencies for flare emission calculations. Given the thousands of flares reported in Subpart W and the technical difficulty to update infrastructure and use large datasets for reporting, the monitoring frequency should be revised to once every hour or as otherwise required by an applicable regulation (e.g., NSPS OOOOb/c). For example, an operator with 1,000 flares with continuous monitors (e.g., thermocouples) would be required to use over 100 million records to calculate the fraction of feed gas sent to unlit flares using a five-minute interval. This amount of data is overly burdensome and would not increase accuracy given the large sample size. Conversely, the number of records decreases to 8.76 million if required to pull pilot flame monitoring data once every hour. The data storage requirements for storing monitoring data at 5-minute intervals for thousands of flares also adds costs and disincentivizes the use of continuous pilot flame monitors.

For flares already connected to SCADA, infrastructure in the form of communication towers, facility-level data storage, and increase in central processing unit capacity would have to be put in place to reliably meet the 5-minute requirement as written in the rule. Additionally, for flares not subject to pilot flame monitoring requirements, installing and connecting continuous monitors to a SCADA, or similar data acquisition system, may not be possible since telecommunications are currently unavailable in many remote areas. Installing new telecommunications in such remote areas also requires approval by various federal agencies (e.g., Federal Trade Commission, Federal Aviation Administration, Bureau of Land Management), which requires additional time for permits and addressing rights-of-way issues with private landowners. In these instances, the Final Rule allows for flares to be monitored once per month for sites that do not have thermocouples or similar devices (and once per week for sites where thermocouples or similar devices are broken). Therefore, it is reasonable to limit the data pulled from monitors to once per hour given the periodicity allowed for visual inspections.

7. EPA should remove the phrase "is present at all times" from the flare pilot flame monitoring requirements since the emission calculations already account for periods when flow is sent to an unlit flare and it is more common for Industry to use auto ignitors.

For flare emission calculations, the Final Rule requires that continuous pilot or combustion flame monitors be "capable of detecting that the pilot or combustion flame is present at all times" [§ 98.233(n)(2)(i)]. The phrase "is present at all times" is unnecessary and should be removed from these requirements since the Final Rule already accounts for periods when flow is sent to an unlit flare. This phrase implies a compliance requirement for a continuously burning pilot or combustion flame. As a reporting rule, Subpart W should not specify compliance requirements but instead focus on accurate reporting of GHG emissions based on available data. An operator can evaluate when flow is sent to an unlit flare based on the available pilot flame and flow monitoring data without the implied requirement for a continuous pilot or combustion flame.

Given the intermittent nature of upstream oil and gas operations, flow to a flare is not steady state; as such, many flares are equipped with an automatic ignition system rather than a continuous pilot. An automatic ignition system allows for a pilot or combustion flame only when needed to control emissions. A continuous pilot flame creates the environmental disbenefit of burning more fuel and generating additional, unnecessary emissions when no vent streams are sent to the control device. At sites without sufficient fuel gas or sites with sour gas, a continuous pilot flame requires propane or other supplemental fuel.

II. Other Large Release Events

EPA has created an untenable framework that could lead to confusion and potential double counting of emissions, which we do not believe EPA has adequately addressed. To improve initial OLRE implementation within Subpart W and to promote innovation and use of advanced monitoring technologies that are rapidly evolving, the Industry Trades request that EPA reconsider the framework finalized in § 98.233(y) as detailed in these comments.

8. Source category emission sources should be bound solely to the empirically based emission calculation methodologies and engineering estimates already captured in § 98.233 and OLRE should be retained only for true sources of emissions that are not yet captured in the Final Rule.

As API stated in its previous comments on the proposed rule,[19] an instantaneous emission detection of 100 kg/hr of methane (or 0.1 metric tons methane/hour) is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple emission sources already captured under Subpart W may have transient large emission rates (e.g. liquid unloading, drilling and completions, etc.). Because some oil and gas emissions are variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate, merely provides information regarding potential observations of a single moment in time.

The emission estimation methods set forth by this Final Rule for named source categories already consider steady-state and upset conditions by nature of monitoring operating parameters for some sources. Therefore, chasing fluctuations over an arbitrary threshold for named sources is overly burdensome and unlikely to yield different results. In these instances, operators will be pursuing data to confirm where to report emissions which may not be vastly different from existing methods. This difference in emissions is de minimis when considered on a per event or per device basis and does not improve accuracy in annual inventories.

Reporters should only determine if the emission event is already captured under the source category using the empirically based calculation methodologies under the Final Rule. This would reduce clerical errors from having to parse out emissions from one category to another as well as meet the original intent of OLRE when originally proposed on June 21, 2022.[20] **Operators should not report named emissions sources under OLRE given the rule's focus on disaggregation to more appropriately attribute emissions to each source.**

9. If EPA retains named source categories under OLRE, under (y)(1)(ii) EPA must clarify the approach for determining the delta is the comparison using the applicable methods under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) versus the calculations using the methodology described in y(2) through (5).

In EPA's Response to Comment, EPA states:

> *"…for sources that have source-specific emission calculations, the emission would be reported according to the provisions for that source, unless the source-specific method understates emissions by more than the threshold defining another large release event. In that exception, the proposed rule stated that the emissions would be reported on a per event basis as another large release event and that the emissions from that event would be excluded from the source-specific calculations and this has been further clarified in the*

[19] https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0234-0402.
[20] 87 FR 36982: https://www.govinfo.gov/content/pkg/FR-2022-06-21/pdf/2022-09660.pdf.

final rule. We agree that double counting those emissions should be avoided and the proposed language achieved that end."[21]

The above explanation is far from straightforward and it is currently unclear how operators should approach the assessment from an OLRE triggering detection. EPA's description is also inherently circular as many of the finalized amendments for other named source categories include use of direct measurement by using a flow meter or conducting other measurements or inspections.

As stated above, EPA should remove named source categories from OLRE. **If EPA retains named source categories under OLRE, EPA must clarify the approach for determining the delta is the comparison using the applicable methods under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) versus the calculations using the methodology described in (y)(2) through (5).**

10. If EPA retains named source categories under OLRE, the criteria specified in § 98.233(y)(1)(ii) must be amended to more appropriately limit when an operator must make these additional assessments for emission allocations.

As we have described immediately above, emission sources already captured elsewhere in § 98.233 should be removed from definition of OLRE as it could lead to an increase in administrative burden. As noted previously, for named source categories, operators will need to pursue data to confirm where to report emissions. Problematically, the result of this added burden is that the result of reported OLRE emissions may not be vastly different than what would be reported using existing methods for those sources. This is especially true given the holistic scope of the final amendments where many emissions sources now have options to perform direct measurement and/or monitoring to improve the accuracy of reported emissions for that source category.

While we agree that the criteria for OLRE should align with the Super Emitter Program (SEP) for sources not already captured under Subpart W, when assessing calculations from typical process emissions like those sources quantified under § 98.233, the threshold must be reasonable when assessing the delta in potential emissions versus other calculation methods that are prescribed elsewhere in the rule. For example, if the OLRE event is determined to be from an unlit flare, the methodology under § 98.233(n) already accounts for time periods when the flare is unlit which presents an unneeded administrative burden to quantify the delta between OLRE and the methods under § 98.233(n). Another example is during well liquid unloading, the initial flow rate initially may begin at a rate 100 kg/hr for the first minute but the total release from the event could be more aligned to an average of 20 kg/hr for the entire unloading event and should remain under its own source category as quantified using the average or measured flow rates per § 98.233(f). In summary, blowdowns are not the only emissions sources with a potentially high-rate, short duration.

Therefore, at a minimum, to alleviate the number of times this assessment could result in clerical errors of allocating where emissions should be reported (increasing the likelihood of double counting emissions), while still promoting the use of advanced monitoring technologies, we believe EPA should update the criteria in § 98.233(y)(1)(ii) to be for events that

[21] Comment 1 in Section 3.4 of EPA's Response to Public Comments.

meet the criteria of 100 kg/hr for at least 1 hour (e.g. continuous 60 minutes) for the referenced source categories.

11. EPA should clarify that "*facility-funded monitoring or measurement data"* in § 98.233(y) is limited to alternate technologies that have been approved by EPA for operator usage under Alternative Test Method for Methane Detection Technology [§ 60.5398b(d)].

Emission measurement technology is rapidly expanding, but many technologies available for commercial deployment are still being evaluated by operators to understand how the technologies work and the best protocols to apply to both the deployment of the technology and the evaluation of the data received. Industry sees much promise in the use of alternate technology and believes the technologies will continue to evolve to a point where direct measurements can be leveraged for emissions reporting across all named emission reporting (see Comment V).

Many technologies can currently identify if large emission rates are occurring or not which can help time bound emission events, but not all technologies can consistently provide accurate quantified emission rates due to varying degrees in the uncertainty of the measured emission rates based on how the technology is used. In other words, through pilot testing of technologies, operators learn the rigor of any quantification algorithm and evaluate how to best utilize and implement the remote sensing equipment for their assets.

We also note that while EPA limited provisions in § 98.233(y)(2)(iv) that establishes how an operator may assess the start time of a potential OLRE to include technologies with a minimum probability of detection; *"[…] at a 90 percent probability of detection as demonstrated by controlled release tests,"* there are no such criteria established for "facility-funded monitoring or measurement" for identifying when/if there is a likely an OLRE for assessment when compared to other prescribed calculation methods.

Therefore, EPA should clarify that when determining the instance of potential OLRE from facility-funded monitoring or measurement data, the approved technologies are limited to those implemented under the NSPS OOOOb alternative technology requirements or those approved for usage by third parties under the SEP. This is especially important if EPA retains named emissions sources categories under OLRE as noted previously in these comments. At a minimum, the same limitation on technology allowed for use when assessing the start time should apply to facility funded programs to increase the likelihood that OLRE assessments are based on valid data compared to current methodologies related to named sources.

12. Audio, Visual, and Olfactory (AVO) inspections should be allowed to determine the start and end point of an emission event. OLRE events are meant to center on the largest emissions sources, which could be identified using AVO.

In the provisions for OLRE that discuss how an operator may determine the start time of an emission event, EPA added the following clause to § 98.233(y)(2)(iv) that was not included in the proposal:

> *"Audio, visual, and olfactory inspections are considered monitoring surveys if and only if the event was identified via an audio, visual, and olfactory inspection."*

It is common practice in the oil and gas industry for operators to conduct AVO inspections to determine if there are any equipment defects which could lead to emissions or other unintended releases. If an operator receives information that indicates an OLRE might be occurring, the AVO records of equipment inspections indicating no emissions releases, should be sufficient to time bound an event because an instantaneous rate of 100 kg/hr would likely be identified by way of AVO.

We support inclusion of AVO inspection records as another means of available information for understanding the duration of OLRE. EPA should expand the use of AVO inspection records in determining the start time of a release for any potential OLRE and not only those that have been identified by AVO. Operators should be able to use all available data, including AVO records, to understand and time bound potential OLRE regardless of the detection methodology used for identification.

13. The provisions finalized in § 98.233(y)(2)(i) should be amended to remove the single root cause and retain each individual emission source as appropriate unless for reasons of fire, explosion or other emergency.

In the Final Rule, EPA finalized the following additional provision in § 98.233(y)(2)(i) that was not proposed, and therefore, we did not have the opportunity to provide previous comment:

> *"For events that have releases from multiple release points but have a common root cause (e.g., over-pressuring of a system causes releases from multiple pressure relief devices), you must report the event as a single other large release event considering the cumulative volume of gas released across all release points."*

This provision to determine the single root cause for multiple emission sources should be removed and each individual emission source should be reported separately. Otherwise, the number of OLRE will be arbitrarily inflated, which reduces and undermines the data accuracy. Furthermore, this approach to aggregate point sources directly conflicts with the other disaggregation that EPA has finalized in the Final Rule and does not help verify emissions. Rather, it inappropriately places emphasis on the use of third-party data collected from remote technology. As an example, there may be an uncontrolled tank battery where emissions from the facility are observed via a flyover or satellite with low spatial resolution sensor to be 120 kg/hr but after an investigative analysis it is determined each tank was associated with only 40 kg/hr of emissions during the flyover. In this example, it would be incorrect to attribute these emissions under OLRE at 120 kg/hr and the emissions should continue to be reported under 'hydrocarbon liquids and produced water storage tanks' where these emissions would be accurately captured for the year.

The Industry Trades believe EPA should provide a pathway to utilize advanced technologies to better inform emissions (see Comment 18). However, the approach should be considered holistically and not only with respect to aggregating individual point sources under OLRE.

14. Reporting in 98.236(y)(11) should be centered on emissions only. The regulatory actions that stem from the SEP are handled directly under SEP.

Within the reporting section, EPA includes compliance assurance level reporting requirements related to measurements detected by third parties under SEP pursuant to § 60.5371b.

As an emission reporting rule, EPA should be seeking information related to emissions so only events that are "other large release events" should be reported. It is inappropriate for EPA to require the reporting of additional compliance information related to the SEP that are not OLREs, as that compliance reporting is driven through a separate regulatory authority. As such, § 98.236(y)(11) should be removed from the reporting requirements for OLRE.

III. Combustion Emissions

15. Emissions from stationary combustion should be reported under Subpart C, consistent with how all other industries report emissions from Stationary Fuel Combustion Sources under Part 98.

Industry Trades' comments, along with numerous other industry comments, requested that EPA align emissions from combustion sources from onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution with emissions reported from combustion sources across all other subparts of the GHGRP by moving those emissions to Subpart C, which is the Subpart EPA codified under Part 98 for General Stationary Fuel Combustion Sources. Emissions from stationary combustion are derived from the use of fuel to power equipment often including the beneficial use gas[22] to reduce "waste" (e.g. or otherwise vented emissions). These emissions are decidedly different from venting, flaring, or fugitive emissions sources and are more appropriately reported under Subpart C across the entire oil and natural gas value chain.

Further, given the interconnection of the WEC and emissions reported under Subpart W, it is unclear why the EPA continues to retain the reporting of combustion emissions inconsistent with respect to certain segments of the oil and gas industry and in comparison, to all other emitting sectors of the U.S. economy that report to the GHGRP. While we recognize emissions from stationary combustion from the three industry segments listed above have always been included under Subpart W, the implication of this historical, arbitrary allocation has important new consequences today when reviewing the bigger picture of the methane regulatory framework that has been implemented in the last two years with respect to oil and gas operations.

Indeed, there is precedent established throughout rulemaking records that establish that emissions from process/operations are not properly classified as "waste." This is a critical

[22] Pipeline quality gas, field gas, process vent gas, or a blend containing field gas or process vent gas

distinction since Subpart W is the reporting framework that Congress has established as basis for the WEC.

NSPS OOOOb/c also include specific compliance pathways for operators that could increase emissions from combustion. Specifically, EPA is phasing out the use of natural gas driven pneumatic controllers to a zero-bleed standard which could necessitate conversion to instrument air driven systems that could be run by a natural gas generator in locations where electricity is unavailable. In the preamble to the Final Rule, EPA asserts that the use of generators to power process controllers creates a net benefit from secondary impacts (89 FR 16926). Another example is the requirements to manage associated gas from oil wells, which includes two compliance options; 1) to recover the gas for use as an onsite fuel source, and 2) to use recovered gas for another useful purpose that a purchased fuel or raw material would serve. Both options may generate some methane emissions from combustion; however, EPA made the BSER determination that these options are equivalent to capturing the gas and routing it to a sales line. While the emission reduction would show up under respective emission sources from these compliance actions, the combustion emissions generated from following the compliance directives would still be subject to the WEC.

While we would agree that emissions from combustion sources should be reported to the GHGRP, it is important that combustion related emissions not be treated as "waste" since this would potentially penalize operators for using the fuel they produce. In addition, operators could be penalized for complying with requirements of NSPS OOOOb/c through the inclusion of those emissions in Subpart W and by extension the WEC (e.g., for sources where venting is minimized such as methane from process controllers, but combustion increases from use of a natural gas driven instrument air system, it is unclear how EPA plans to reconcile the compliance related exemptions).

In the 2024 TSD for the Final Rule,[23] EPA continues to justify retaining combustion emissions under subpart based on whether the gas is of; 1) pipeline quality specification and has a minimum higher heating value of 950 BTU/scf, or 2) if the fuel is natural gas that does not meet these criteria, field gas, process vent gas, or a blend containing field gas or process vent gas. We note the methodologies to calculate emissions with respect to this distinction could be moved in their entirety to Subpart C where they belong and could apply to all applicable industries. Additionally, the analysis EPA conducted in the TSD comparing the methods under Subpart C and Subpart W only shows the inherent uncertainty of any emission factor developed for any gas constituent published in any quantification protocol.

The lack of consistency and transparency in the GHGRP for combustion related emissions is arbitrary and appears to hyperfocus on an emission stream that is not derived from waste but subjecting these emissions to a waste fee assessment. The allocation of combustion emissions under Subpart C would strengthen the accuracy of emissions reporting in the GHGRP. Additionally, the methodology under Subpart W does not impact how combustion emissions are quantified, but only how they get reported under the regulation. **Therefore, for consistency and transparency in**

[23] https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0453

emissions reported from sources of stationary combustion using fuels and to better align emissions reported under Subpart W to how Congress intended the WEC to function, combustion emissions should be reported under Subpart C.

16. The list of approved testing methods for measuring methane slip should be amended to include ASTM D6348-03 to be consistent with other stack testing provisions.

The Final Rule lists three test methods for measuring methane slip from engines or turbines during a performance test [§ 98.234(i)]:

- EPA Method 18,
- EPA Method 320, and
- ASTM D6348-12 (Reapproved 2020).

The ASTM method does not align with the performance testing provisions in 40 CFR 60, Subpart JJJJ (NSPS JJJJ) and 40 CFR 63, Subpart ZZZZ (MACT ZZZZ), which still list a previous version of the ASTM Method, ASTM D6348-03 [Table 2 to Subpart JJJJ of Part 60 and Table 4 to Subpart ZZZZ of Part 63].

This inconsistency could prevent operators from utilizing NSPS JJJJ or MACT ZZZZ performance tests for Subpart W reporting or require duplicative testing; a NSPS JJJJ or MACT ZZZZ performance test using ASTM D6348-03 and a separate Subpart W performance test using ASTM D6348-12.

While we acknowledge EPA's notation that this method is outdated (FR 89 42181), it is currently one of the methods operators must use for compliance with the engine rules (i.e., NSPS JJJJ or MACT ZZZZ). Until EPA amends test references under the engine rules, EPA should allow operators to leverage data collected under other EPA regulations, as applicable. To better align the test methods in the Final Rule with existing NSPS JJJJ and MACT ZZZZ requirements, EPA should add ASTM D6348-03 to the list of approved test methods for methane slip at least until such time that NSPS JJJJ and MACT ZZZZ are updated to include ASTM D6348-12. As noted in the Final Rule preamble [89 FR 42216], EPA currently allows ASTM D6348-03 under other Part 98 subparts including Subparts I (Electronics Manufacturing), V (Nitric Acid Production), and OO (Fluorinated Gas Production).

17. EPA should clarify that performance tests from the most recent test year can be used for methane emissions from reciprocating natural gas engines and natural gas turbines.

Section 98.233(z)(4)(i) appears to be clear that when multiple tests are conducted during a reporting year, the average is to be used. It is not clear if a test is performed prior to a reporting year whether that test result is required to be used or can voluntarily be used. One common scenario is a state requirement for a test after startup may have occurred in year 1. To achieve the most realistic methane emissions in year 2 and beyond, the GHGRP reporter should use this test in subsequent years rather than using the Subpart W default values.

IV. Allowing Use of Representative Samples Rather Than 100% Population Measurement

Consistent with the directives in CAA § 136(h) that reported emissions be based on empirical data, the use of observed data should be leveraged for all emissions sources to more accurately report emissions. Congress recognizes that empirical data have merit, and EPA can and should expand their use. For example, EPA should allow for the development of emission factors based on sufficient facility-specific measurements to be considered statistically representative, which is the same approach EPA used to derive default emission factors included in Subpart W.

Such an approach is also allowed in other voluntary measurement frameworks commonly utilized within the oil and natural gas sector.

Development of representative emission factors is an appropriate use of empirical data for a basin, similar facility types, sources which combust fuel with similar composition, and like-kind equipment.

While the EPA included methodologies to develop representative emissions factors and some sources are already allowed to utilize a similar approach (e.g., as-found compressor measurements, mud degassing, equipment leaks under § 98.233(q)), there are numerous instances where EPA falls short of truly allowing the use of empirical data to derive component-specific representative emission factors including:

- Flares of the same design and model that are performance tested or have manufacturer guarantees
- Engines of a similar size and type that are stack tested
- Crank case vents that are measured
- Pneumatic devices (see also Comment VI)
- Pneumatic pumps
- Rod packing vents subject to NSPS provisions versus those that are not subject (located at a well site) or not yet subject (specific to onshore production and onshore gathering and boosting only)

V. Alternative Technology Approval

18. EPA should allow for efficient approval of alternative emissions measurement technologies and methods for all emission sources.

As advanced technology matures, EPA should provide a pathway to leverage data collected by providing an onramp for operators to use alternative emissions measurement technologies to estimate GHG emissions across emissions sources. As it stands, EPA would require lengthy notice-and-comment rulemaking to approve the use of alternative technology.[24] Failing to incorporate a way for operators to use new and more efficient and accurate technology as they evolve stands to chill the development and adoption of such technology.

We recognize that EPA must evaluate alternative emissions measurement technologies before allowing operators to use them for compliance purposes, but requiring notice-and-comment rulemaking is unnecessary. There is precedent for this kind of efficient process in other CAA programs. In these other programs, EPA routinely approves alternative test methods without notice-and-comment rulemaking.[25,26] These alternative test method approval procedures exist, in part, to allow use of new and improved test methods. EPA reasons, "[a]s pollution controls improve and emissions decrease, it may be necessary or desirable to utilize newer methods with advantages such as lower detection limits."[27] The same logic should apply here. We simply ask for the ability to request efficient approval of GHG emissions measurement technology, as exists in these other programs. Opening this door would allow for and encourage development, and consequently widespread use, of new and improved measurement technologies.

A rulemaking barrier to widespread adoption of these new technologies will significantly l slow their growth and scale. As EPA suggests in the Final Rule a party must first petition EPA for rulemaking, EPA must consider (likely for months or longer) whether to initiate rulemaking, and then EPA must draft a proposal. Then, at least 9 to 12 months will pass before finalizing an amendment that would allow use of the new technology. In other words, EPA is setting up a potentially years-long barrier to adoption of improved technologies and without a founded basis.

While we note that current technologies do not have the precision required to estimate emissions from direct measurements, there are other pathways or protocols that can be developed that leverage data from these technologies and included within § 98.234 without a notice and comment rulemaking. Industry Trades look forward to continuing dialogue and working with EPA on how best to develop these protocols and promote the use of advanced technology with respect to reliable emission quantification across emissions sources.

VI. Pneumatic Devices

19. Under Method 3, the methodology to conduct screening on intermittent devices in onshore production and gathering and boosting must be amended to allow for a more workable program based on relevant empirical data.

In the proposed rule, EPA had offered a calculation pathway for intermittent devices that included sampling the population of pneumatic devices for the facility and applying the data collected to be applied to the population not monitored.[28] In the Final Rule, EPA has amended this provision for

[24] *See* 89 FR 42062, 42173.
[25] *See* 40 CFR §§ 60.8, 61.13(h)(1)(ii), 63.7(e).
[26] *See* Notice of Broadly Applicable Alternative Test Methods, 72 FR 4257, 4258 (Jan. 30, 2007).
[27] *Id.*
[28] 88 FR 50383.

monitoring intermittent devices to apply only to sites that conducted the monitoring, essentially removing the use of empirical data to inform the results.

Extrapolation would not lead to a material decrease in accuracy given the sample size for monitoring would be relatively large for most operators. EPA should revert to including the proposed methodology as written within the proposed rule that allows operators the ability to sample 20% of their intermittent bleed devices and extrapolate the results of the leaking/no leaking factors to the rest of the population.

Developing a sampling protocol is consistent with EPA's approach retained under Method 2 for certain continuous bleed devices still in operation in certain industry segments. Utilizing representative sampling is a common practice to determine overall efficiencies and would be more aligned with the directives in CAA § 136(h) that reported emissions be based on empirical data. In fact, most of the factors promulgated by EPA were determined by studies using statistical sampling. EPA's disallowance of this methodology for pneumatics is arbitrary and capricious.

20. For calendar year 2024 data, EPA must clarify that they intended for operators to have the ability to use OGI based on amendments to cross references in § 98.234(a) that are not effective until January 1, 2025.

The Final Rule amendments for Calculation Methodology 3 that are effective July 15, 2024, covering calendar year 2024 appear to inadvertently refer to the same citations in § 98.234 as the amendments finalized for RY 2025; however, the associated amendments to § 98.234 that reorder the OGI requirements are not effective until January 1, 2025. Specifically, the provisions in effect for calendar year 2024 point to § 98.234(a)(1) through (3), which are linked to OGI using the alternate work practice at 60.18, Method 21 and use of infrared laser beams. The same cross references effective January 1, 2025, include OGI using § 60.5397a and Appendix K.

We believe the provision finalized § 98.233(a)(3)(ii)(A) for the 2024 calendar year is a typographical error, and EPA should clarify that they intended operators to have the ability to use provisions currently in effect for 2024 at § 98.234 (a)(1) through (6).

21. Clarification is required for Calculation Method 2 during emergency and other unintended situations for controllers designed to be zero bleed.

For Calculation Method 2, EPA should add a specific exclusion for zero-bleed pneumatic devices which vent by exception, such as wellhead emergency shut down devices, from the requirement to measure emissions provided no emissions are detected from the device in normal operating (non-venting) conditions using Method 21, OGI, or AVO.

As it stands, operators would be required to force the zero-bleed pneumatic to actuate for 15 minutes to measure the emission rate. This is an environmental disbenefit and would require hundreds of thousands of devices to be measured needlessly. If EPA chooses to exclude these devices and emissions are not detected from the pneumatic device using Method 21, AVO or OGI, then no emissions must be measured or reported from the device except for those emissions associated with the actuation of the device as determined from company actuation records. If emissions are detected via Method 21, OGI, or AVO, emission quantification would be required in addition to engineering calculations with company records for those instances where the pneumatic device actuated.

VII. Hydrocarbon Liquids and Produced Water Storage Tanks

22. For Calculation Method 1 for hydrocarbon liquids and produced water storage tanks, EPA should clarify that measured input parameters, including sampled composition, can be representative of the facility (i.e., basin) and are not required for each individual tank or site.

The Final Rule imposes the following requirements for hydrocarbon liquids and produced water storage tanks emissions calculations:

- Calculation Method 1 (flash emissions modeling software) must be used to calculate GHG emissions if such software is used for compliance with federal or state regulations, air permit requirements, or annual inventory reporting.
- If Calculation Method 1 is used, the following parameters must be measured if required as a model input:
  - Well, separator, or non-separator equipment temperature and pressure must be measured at least annually, and
  - Liquid composition must be sampled within 6 months of startup or by January 1, 2030, whichever is later, and at least once every five years thereafter.

These requirements virtually eliminate Calculation Methods 2 and 3 and imply that a site-specific model run must be performed annually since modeling software is typically used for compliance with federal or state regulations, air permit requirements, or annual inventory reporting. **EPA must continue to allow representative input parameters for Calculation Method 1 for hydrocarbon liquids and produced water tanks.** Annual site-specific model runs will cause resourcing issues, both in terms of measurement/sampling and calculations, without greatly increasing the accuracy of reported emissions since model runs for other purposes frequently use representative operating conditions and samples, as was previously allowed under Subpart W and is currently used by state permitting and compliance programs. States, including Texas, Oklahoma, and New Mexico, already have representative sampling guidelines[29,30] and allow the use of representative sampling for air permitting and emissions inventories.[31]

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[29] Texas Commission on Environmental Quality, Representative Analysis Criteria (Revised February 2012). https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/rep-analysis-criteria.pdf Accessed June 13, 2024.

[30] https://www.deq.ok.gov/wp-content/uploads/air-division/PG_Representative_Sample_Guidance_and_Flowchart.pdf

[31] New Mexico Environment Department, Emissions Inventory Guidance Document, Appendix C (Updated February 6, 2024). https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2024/02/AEIRGuidancedoc02062024.pdf Accessed June 13, 2024.

If only site-specific model runs are allowed under Subpart W, then the following will be required based on over 182,000 atmospheric tanks reported for RY 2022 (the number of reported tanks is expected to at least double with the inclusion of produced water tanks):

- Tens to hundreds of thousands of measurements (well, separator, or non-separator equipment temperature and pressure) will need to be taken annually,
- Tens to hundreds of thousands of liquid samples (composition, API gravity, and RVP) will need to be taken and analyzed every 5 years, and
- Tens to hundreds of thousands of model runs will need to be updated annually.

This number of annual measurements and model runs will put a significant burden on operators and their contractors. Also, this number of liquid composition samples, even over a 5-year period, may strain or potentially exceed existing laboratory capacity; SPL highlighted the potential for NHV sampling under NSPS OOOOb to exceed existing laboratory capacity in its March 19, 2024, letter to EPA, which is included as Appendix 2.

23. Tank sensors that are not connected to SCADA should not be required to be used to determine periods when thief hatches are open.

The Final Rule requires that thief hatch sensors or tank pressure sensors are to be used to determine periods when the thief hatch is open on a controlled atmospheric pressure storage tank [§ 98.233(j)(7)]. This requirement should be revised such that thief hatch sensors and tank pressure sensors that are not connected to a SCADA or similar data acquisition system, are not required to be used to determine periods when thief hatches are open. Requiring the use of data from unconnected sensors is impractical since logging such data would require operators to take manual readings periodically. Connecting existing sensors to SCADA is expensive or technically infeasible since telecommunications are currently unavailable in many remote areas. Installing new telecommunications in such areas for SCADA requires permitting and approval by various federal agencies (e.g., Federal Trade Commission, Federal Aviation Administration, Bureau of Land Management). **For these reasons, only data from thief hatch sensors or tank pressure sensors that are connected to SCADA should be required to be used to determine periods when thief hatches are open.** The monitoring and QA/QC requirements under § 98.234 and Subpart A should also be adjusted as needed for consistency.

24. EPA should provide a 2-year on-ramp that allows visual inspection of storage tanks equipped with pressure monitors.

As written in the Final Rule, EPA requires operators who have pressure sensors on their storage tanks (and no thief hatch sensor) to use the pressure sensor data to determine if the thief hatches are open and report emissions resulting from open thief hatches using a 0% capture efficiency.[32] If

[32] 40 CFR § 98.233(j)(4)(i)(C), (j)(7).

an operator does not have pressure or thief hatch sensors on their storage tanks, they may conduct periodic visual inspections of their tanks to determine if the thief hatch is open.[33]

Where operators have equipped storage tanks with pressure sensors, they need time to implement the IT systems necessary to properly interpret and record data for reporting. Additionally, pressure sensors may not be connected to data transmittal systems (see discussion immediately above in Comment), meaning operators must connect the sensors to those systems if they exist, install transmittal systems, or implement processes to manually collect locally stored data. All these activities will take significant time and resources. We appreciate the ability to use pressure sensor data, but the option was not in the proposal meaning operators have had only a few months to begin implementation. Additional time is needed.

We request that EPA allow for a 2-year on-ramp period that gives operators who use pressure sensors on their storage tanks the option to conduct periodic visual thief hatch inspections in lieu of using pressure sensor data. Operators could use pressure sensor data to estimate emissions during this period but would not be required to. This would afford operators the necessary time to understand the pressure sensor data and establish accurate pressure thresholds for open thief hatches on a system-by-system basis.

25. EPA should not require annual AVO inspections on controlled tank thief hatches that are unsafe to monitor.

As written in the Final Rule, EPA requires operators to conduct at minimum an annual inspection for open thief hatches via AVO. Many storage tanks contain sour gas that prevents an AVO inspection from being performed safely. NSPS OOOOa/b contain provisions to develop a separate program and frequency of inspections for unsafe-to-monitor equipment. Subpart W should be revised to similarly allow alternatives for unsafe-to-monitor conditions.

VIII. Blowdown Vent Stacks

26. EPA must continue to allow the use of best available data when determining the temperature and pressure of all blowdowns.

In both sets of finalized amendments covering both RY 2024 and RY 2025, EPA has limited the use of best available data when determining inputs to equations W-14A and W-14B for temperature and pressure. Specifically, EPA is only allowing use of best available data with respect to emergency blowdowns located within a limited subset of industry segments.

In limiting the use of best available data to only certain segments for emergency situations, EPA states their reasoning to "*allow engineering estimates based on best available information when*

[33] *Id*. § 98.233(j)(7).

determining temperature and pressure for emergency blowdowns, is due to the geographically dispersed nature of the facilities in this industry segment." [34]

This reasoning is flawed because the reality is such that in an emergency (such as a fire or explosion), regardless of which segment the blowdown might occur, operators will need the ability to reference the best available data to determine the temperature or pressure. In the example of a fire, the temperature or pressure gauges could be ruined. Emergency blowdowns in every industry segment should be allowed to use the best available data in emergency situations (i.e., onshore gas processing).

Additionally, as other commenters noted to EPA on the proposed rule,[35] it is untenable to require direct measurement of every potential blowdown point as it would potentially require installation of thousands of temperature and pressure gauges throughout the oil and gas value chain. Based on review of data submitted from 2018-2022, there were over 300,000 thousand blowdowns reported for the onshore gathering and boosting segment as shown in Table 3.

Table 3. Count of Blowdowns Reported pursuant to 40 CFR Part 98 between 2018-2022 for the Onshore petroleum and natural gas gathering and boosting source category. [36]

Count of Blowdowns Reported by Type	Calendar Year				
	2018	2019	2020	2021	2022
Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)]	**349,970**	**341,464**	**414,308**	**374,016**	**367,275**
All other equipment with a physical volume greater than or equal 50 cubic feet	24,959	32,214	27,537	19,100	13,825
Compressors	227,696	216,614	259,131	232,589	258,553
Facility piping	2,428	1,698	13,798	12,722	1,721
Pig launchers and receivers	67,775	67,001	96,126	89,414	82,339
Pipeline venting	9,591	9,034	3,370	13,230	3,827
Scrubbers/strainers	3,063	2,780	3,490	3,745	4,687

In the Response to Comments, EPA's only rationale was that *"The EPA considers expanding the use of engineering estimates rather than measurements to blowdowns other than emergency blowdowns to be contrary to the directives in CAA section 136(h), including ensuring accuracy in total emissions reported."* We do not agree with EPA's rationale based on the practicality of acquiring the necessary gauging to directly conduct measurements for every blowdown event. Through use of best available data, operators could review data of nearby equipment that is

[34] 98 FR 42088
[35] Page 443 of EPA's Response to Comments: EPA-HQ-OAR-2023-0234-0456
[36] Query was executed on Jun 17, 2024, 12:55 PM: https://enviro.epa.gov/query-builder/query-search/ac18881a-6727-4215-964a-8c593de5e155

operating at relatively the same pressure and/or temperature to assess the most likely actual conditions of when the blowdown took place. This approach does not undermine the validity of the estimated emissions reported as the temperature and pressure estimated based on best available data is assumed to be representative of the emissions event. **Therefore, EPA should continue to allow the use of best available data including the use of engineering estimates when determining the temperature and pressure of all blowdown events when direct measurement of these parameters is unavailable.**

27. Reporting blowdown emissions that occur midfield to the closest facility or the site that had the largest portion of emissions is an arbitrary allocation and emissions should be reported from pipelines at the State level consistent with the definition of a gathering pipeline site finalized in § 98.238.

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting emissions arbitrarily to "*either the nearest wellpad or gathering and boosting site upstream from the blowdown event or the well-pad or gathering and boosting site that represented the largest portion of the emissions for the blowdown event"* is not only challenging but an inaccurate depiction of where and how these emissions occur. In many cases, the closest well or compressor station could be miles away and have no connection to the reason or cause for the blowdown.

The Industry Trades previously recommended that EPA allow these types of blowdown events to be aggregated by county, which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA). In EPA's Response to our comment, EPA stated,

> *"Regarding the concern with reporting a site for mid-field pipeline blowdowns or other similar circumstances, in the final provisions, the EPA has provided guidance in 40 CFR 98.236(i)(1) and (2) to assist with these kinds of determinations. The final provisions direct reporters to associate the blowdown with either the nearest wellpad or gathering and boosting site upstream from the blowdown event or the well-pad or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate. This approach for reporting is more appropriate for the final rule than a county-based approach because very little data will be reported on a county (or sub-basin) basis with the changes in reporting levels described in section III.D. of this preamble. Further, it is similar to the established approach for assigning blowdowns and emissions to an equipment or event type when a blowdown event results in emissions from multiple equipment or event types."*

While EPA's approach to Subpart W reporting is evolving to have fewer data points reported at a county level, arbitrarily assigning emissions to site locations is inaccurate and the opposite of transparent when reporting all emission sources within a basin. Gathering pipelines exist to transfer production between site locations (i.e. well pads and gathering and boosting sites), and pig launchers and receivers typically exist along pipelines. These sources would not necessarily have any connection to the closest "site" nor have any cause to associate emissions to such a site or facility. For example, pig launchers and receivers may occur simply for safe maintenance of the gathering line and not due to any other reason that would link the emissions to a site identifier.

EPA also does not appear to have contemplated fully how the reporting requirements relate to how EPA has defined *Gathering pipeline site to* mean:

> *[…]all the gathering pipelines within a single state. A gathering pipeline site is a type of gathering and boosting site for purposes of this subpart."*

We continue to believe there are a subset of emissions that cannot be disaggregated without arbitrary allocation creating an additional administrative burden to perform these assignments. **Based on the new definitions that EPA has finalized defining gathering pipeline sites, the Industry Trades request that EPA provide clarification that blowdowns for pipelines should be reported at the State level since a gathering pipeline site means all gathering pipelines in a state and this also extends to pig launchers and receivers that exist along the pipeline.**

IX. Equipment Leaks

28. EPA should allow operators of gathering pipelines to conduct periodic leak surveys as an alternative to applying the default leak factor.

The Final Rule requires operators of gathering pipelines to estimate GHG emissions using a default population emission factor (derived from a combination of leak rate and count) multiplied by the length of pipeline, among other things.[37] This methodology assumes every gathering pipeline will have the same number of leaks, at the same leak rate, for every mile of pipeline while operating, regardless of whether it is monitored periodically for leaks. EPA should allow operators to conduct periodic leak surveys and apply a default leak rate factor to detected leaks to estimate gathering pipeline GHG emissions.

EPA's default population emission factor for gathering pipelines incorporates an assumed default leak rate and count. EPA based the default population emission factor on two studies. For the default leak rate, EPA relied on the 2015 Lamb *et al.* study.[38] EPA chose not to use another recent study by Yu *et al.*, published in 2022,[39] because it relied on aerial measurements rather than ground-based leak measurements and did not specify the pipeline material.[40]

Both the 2015 Lamb *et al.* and the 2022 Yu *et al.* studies found that pipeline leaks have highly skewed emissions data distribution driven by a few large leaks. Consequently, the finalized gathering pipeline default assumed leak rate for the default population emission factor skews in

[37] 40 CFR § 98.233(r).
[38] 89 FR 42176.
[39] Jevan Yu et al., Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin, Env't Sci. Tech. Letters (2022), https://pubs.acs.org/doi/full/10.1021/acs.estlett.2c00380.
[40] *See* 89 FR 42090; U.S. EPA, Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems, 111 (June 2023) (hereafter "Proposal's Technical Support Document").

favor of large leaks, which assumes each gathering pipeline would have large leaks. We are not convinced this is true, and these large leaks are exactly the type that operators would find through advanced monitoring, like a flyover. Moreover, the Lamb *et al.* study was a study of distribution pipelines, not gathering pipelines. Distribution pipelines are not necessarily representative of gathering pipelines. For example, distribution pipelines may operate at higher pressures which, in turn, may result in more expected leaks.

For the assumed leak count (leaks per mile of pipeline) in the default population emission factor, EPA relied on a GRI/EPA study that is almost 30 years old.[41] Operation methods and monitoring have changed over the past 30 years, and this study may not accurately reflect current-day leak counts. For example, many operators conduct voluntary leak surveys that were less common 30 years ago, meaning today's gathering pipelines are likely to have fewer leaks than those in the study.

Therefore, EPA should allow operators to periodically screen gathering pipelines for leaks using advanced measurement techniques (just as the Lamb and Yu studies did). If the survey finds no leaks, the operator will report zero emissions. If the survey finds a leak, we recommend that the operator estimate and report emissions from the leak using the average methane leak rate (scf/hr/leak) from Table 12-2 of the Proposal's Technical Support Document.

Absent our approach, Subpart W provides no incentive for leak surveys because operators would not be able to use empirical data to report lower gathering pipeline emissions, even on a system that is demonstrated to be leak-free. Allowing our recommended approach would be consistent with, if not required by, Congress' clear directive to EPA under CAA Section 136(h) to allow operators to "submit empirical emissions data" in furtherance of the goal of achieving an emissions inventory reflective of actual emissions.

29. For components surveyed per § 98.233(q), the methodology to determine leak duration should be revised with more representative assumptions, including an option that utilizes the date the component is repaired.

For equipment leak surveys, the Final Rule [§ 98.233(q)] retains the previous methodology for determining leak duration that does not consider repair data. Since this rulemaking was supposed to allow operators to use empirical data in calculating GHG emissions in accordance with CAA § 136(h), EPA should revise the leak duration to end with repair as confirmed by re-monitoring of the component. Repair information is empirical data that indicates the component is no longer leaking. The Final Rule requires the use of leak data from NSPS OOOOa/b/c surveys but does not allow the corresponding repair data to be used to limit duration. While NSPS OOOOa/b/c allows components to be placed on delay of repair, the repair date would still be used under this approach.

[41] *Id.*

EPA should compare its previous "model" facility analysis[42] with actual survey and repair data from NSPS OOOOa reports. In this analysis, EPA compares four options for leak duration based on estimated emissions from two model facilities with identical leak profiles but different semiannual survey dates.

- Facility 1 – June 30 and November 30
- Facility 2 – January 31 and May 31

Option 3 in this analysis considered repair date to end leak duration but appeared to underestimate emissions from Facility 2, which conducted two semiannual surveys early in the year. The Industry Trades note that Facility 2 would have to conduct an additional survey by December 31 (7 months from May 31) if subject to NSPS OOOOa. This additional survey or a later second survey date (e.g., June 30 instead of May 31) would increase the estimated emissions for Facility 2 under Option 3. Additionally, EPA's previous analysis did not include quarterly surveys as now required by NSPS OOOOb/c; more frequent surveys lead to shorter periods where no leaks are assumed to be present. Quarterly surveys under NSPS OOOOb/c must be conducted at least 60 days apart, and repairs must be completed within 60 days except as provided by delay of repair requirements.

EPA should also update the leak duration to allow a mid-period duration assumption since it is a more reasonable assumption than the entire period from the previous survey. On average, leaks would occur around the mid-point between surveys with some leaks occurring before and some occurring after the mid-point. EPA previously did not consider a mid-period duration assumption since *"it adds a level of complexity to the calculations."*[43] However, this approach only requires operators to track repair information to determine whether to use half the period or the entire period between surveys. In other words, leak duration would start at the mid-point from the previous survey and end with the repair date. Many operators are already required to track component repair under NSPS OOOOa/b. While this complexity would increase the burden on reporters, EPA should allow operators to use this more complex option since it would be a more reasonable assumption for leak start. **In conclusion, EPA should revise the leak duration to start at the mid-point from the previous survey and end with the repair date since it would be more reasonable and empirically based; in the case of delay of repair, the leak duration would continue through subsequent surveys until repair.**

30. EPA should not implement an enhancement or undetected leak "k" factor without more recent study data.

For equipment leak surveys, the Final Rule includes an adjustment factor for undetected leaks, or "k" factor, for each detection method [§ 98.233(q)]. Since the "k" factor was developed from a

[42] EPA–HQ–OAR–2015–0764-0066, "Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule".
[43] EPA-HQ-OAR-2015-0764-0067

single study with data collected from 2015,[44,45] which occurred before NSPS OOOOa compliance, it does not include the approximately 8 years of OGI experience and learnings gained from those surveys. EPA should not implement a "k" factor without more recent study data.

The study data are roughly 9 years old and do not include the experience from thousands of NSPS OOOOa surveys. EPA did not fully justify why such dated information reflects the current comparative performance of various leak detection methods nationwide. The agency's additional analysis in the Final TSD is mostly circular since the study data was used for inputs, derivation of the leaker and "k" factors, and results validation.

Furthermore, grossing up individual component emission factors is an illogical approach to account for undetected leaks. Various leak detection methods have inherent limitations that are beyond an operator's control (e.g., accessibility of components, different leak definitions, etc.). 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 as part of the National Inventory process, rather on an individual component and operator basis. If the "k" factor approach remains, EPA should allow operators to develop a facility-specific "k" factor based on representative data in accordance with CAA § 136(h). In conclusion, the "k" factor approach is inappropriate, and EPA should consider more recent study data before implementing an undetected leak adjustment factor or at a minimum, allow operators to derive facility-specific "k" factors based on representative data.

31. Given the limited number of data points from which the OGI leaker factors were derived, EPA should derive separate leaker factors for compressor vs. non-compressor components in "gas service".

The Final Rule contains new leaker emission factors for onshore production and onshore gathering and boosting [Table W-2 to Subpart W of Part 98]. As shown in Table 9-2 of the Final Rule TSD,[46] 8 out of the 13 leaker emission factors for OGI were derived with less than the 50 measurements required for an operator to derive a facility-specific leaker factor.[47]

Given the limited data from which the OGI leakers were derived, EPA could and should derive separate leaker factors for compressor versus non-compressor components in "gas service" to avoid overestimating emissions from more common, non-compressor components. Distinguishing between compressor and non-compressor components has long been utilized by EPA and even included for other industry segments in the Final Rule.

[44] Pacsi, A. P., *et al.* "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States.'' Elem Sci Anth, 7: 29, available at https://doi.org/10.1525/elementa.368. 2019

[45] The study took 324 leak measurements at 65 sites in 4 basins between June 2015 and December 2015.

[46] https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0453

[47] In fact, the entire set of "oil service" emission factors were derived from only 37 measurements with three components having no measurements at all.

X. Dehydrators

32. EPA should continue to allow feed natural gas water content to a glycol dehydrator to be based on a technically sound assumption of saturated gas.

The Final Rule requires that the feed natural gas water content to a glycol dehydrator be measured annually if Calculation Method 1 is used [§ 98.233(e)(1)(ii)]. Rather than requiring an annual measurement, EPA should continue to allow feed natural gas water content to be based on a technically sound assumption of saturated gas. EPA did not respond to comments on the Proposed Rule that feed natural gas water content is not typically measured and is calculated by the process simulation software with a technically sound assumption of saturated gas. Both the current and Final Rule acknowledge that saturated gas is a technically sound assumption since it is allowed if only dry natural gas composition is available [§ 98.233(e)(1)(xi)(B)]. Furthermore, EPA did not qualify the anticipated impact on emissions estimated from assuming saturated feed versus a measured content (which would be less than saturated) and the additional expense for reporters has not been adequately justified by EPA to show how this would improve reporting accuracy.

In a 2015 National Oil and Gas Emission Inventory Workgroup,[48] EPA also acknowledged that the wet gas water content is "normally saturated." Therefore, requiring annual measurements for the feed natural gas water content does not increase the accuracy of reported emissions and does not support or compliment any other state or federal regulatory compliance program. Given the long standing and technically sound assumption of saturated gas and the thousands of annual samples required if Calculation Method 1 is used (e.g., greater than 6,700 dehydrators reported under Calculation Method 1 for RY 2022), EPA should remove the annual measurement requirement for feed natural gas water content and continue to allow the parameter to be based on the conservative default of saturated gas.

XI. Other Reporting Topics

33. EPA should clarify that operators may use common industry practices to determine liquid throughput and changes in ownership (i.e., "sales").

The Final Rule amends facility level reporting at 98.236(aa) from the use of best available data to the following:

> *"Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using <u>a flow meter that meets the requirements of § 98.234(b) for quantities that are sent to sale</u> or <u>through the facility and determined by using best available data for other quantities</u>. If a quantity required to be reported is zero, you must report zero as the value."*

[48] GLYCalc and E&P TANK, National O&G Emission Inventory Workgroup, March 12, 2015. https://vibe.cira.colostate.edu/ogec/docs/meetings/2015-03-12/NationalOGEmissionWorkGroup_031215_GLYCalc_EPTank4.pdf Accessed June 14, 2024.

The above language is confusing as far as to what can be determined by best available data versus what must be metered. Furthermore, it is common practice to use tank gauging, for example, to monitor liquid levels including for changes in ownership (i.e., sales). The requirement by EPA to utilize a flow meter only will require hundreds or thousands of flow meters to be installed, which is economically infeasible given the number of tanks that are gauged in remote areas that do not have access to telecommunications. EPA should amend this requirement to allow for accepted industry practices when determining liquid throughput.

XII. Compressors

34. Compressor Measurements under Subpart W should allow calculation pathways that align with the compliance driven provisions under NSPS OOOOb/c.

Under NSPS OOOOb/c, EPA has allowed a compliance pathway for operators to change the compressor's rod packing annually in lieu of conducting measurements. Under 98.233(p)(11), it appears the measurements are still required for purposes of reporting emissions under Subpart W, even if annual replacement is occurring. For operators performing this work practice option, EPA should clarify that use of the default emission factors is allowed for all compressor sources related to that compressor including emissions from the rod packing, blowdown vents, and isolation valves. In absence of this clarification, Subpart W directly conflicts with the finalized requirements of NSPS OOOOb/c making this compliance option irrelevant.

Additionally, while we appreciate EPA not requiring annual measurements in each operating mode, the requirements still require clarification. Specifically, for compressors following NSPS OOOOb and conducting annual measurements on rod packing vents, it is unclear how the reporter emission factor for non-operating and standby compressor modes would be determined for the first few years of implementation as most measurements will likely be done in operating mode based on provisions for NSPS OOOOb. If there are no measurements conducted in these modes, EPA should allow an option to use the default emission factor (a method that is already provided in the rule in Table W-2[49]) to provide a methodology to estimate emissions appropriately from the blowdown vent and isolation valve.

[49] From preamble: "The edits also clarify that the default leaker emission factors for the open-ended line (OEL) component type includes the blowdown valve and isolation valve leaks when using the population count emission factor approach specified in 40 CFR 98.233(o)(10)(iv) or (p)(10)(iv). "

Appendix 1

Industry Trades NHV Data submitted to EPA

3/18/2024

ohn Beath Environmental, LLC

triving to make something better every day

Operator Survey: Net Heating Value

American Petroleum Institute

AMERICAN EXPLORATION & PRODUCTION COUNCIL

NHV Survey – Overview and Results

; February and early March 2024, the
can Petroleum Institute (API) and American
ation and Production Council (AXPC)
cted an operator survey of the Net Heating
(NHV) of low-pressure (LP) gas streams that
be sent to a control device.

tent of this data collection was to
stand the distribution of NHV and how it
s the Environmental Protection Agency's
) understanding of the NHV monitoring (or
ate sampling demonstration) requirements
ntrol devices in the final rule "Standards of
mance for New, Reconstructed, and
ed Sources and Emissions Guidelines for
g Sources: Oil and Natural Gas Sector
e Review."

nply with antitrust guidelines the survey
inded, and data was gathered and complied
ird-party consultant.

Dataset represents:

- Over 22,000 total data points
- 18 operators
- ~4,300 sources
- ~4,200 sites
- 12 basins (99% from 5 basins)
- 11 years (95% within last 3 years)

Results of Survey and Analysis:

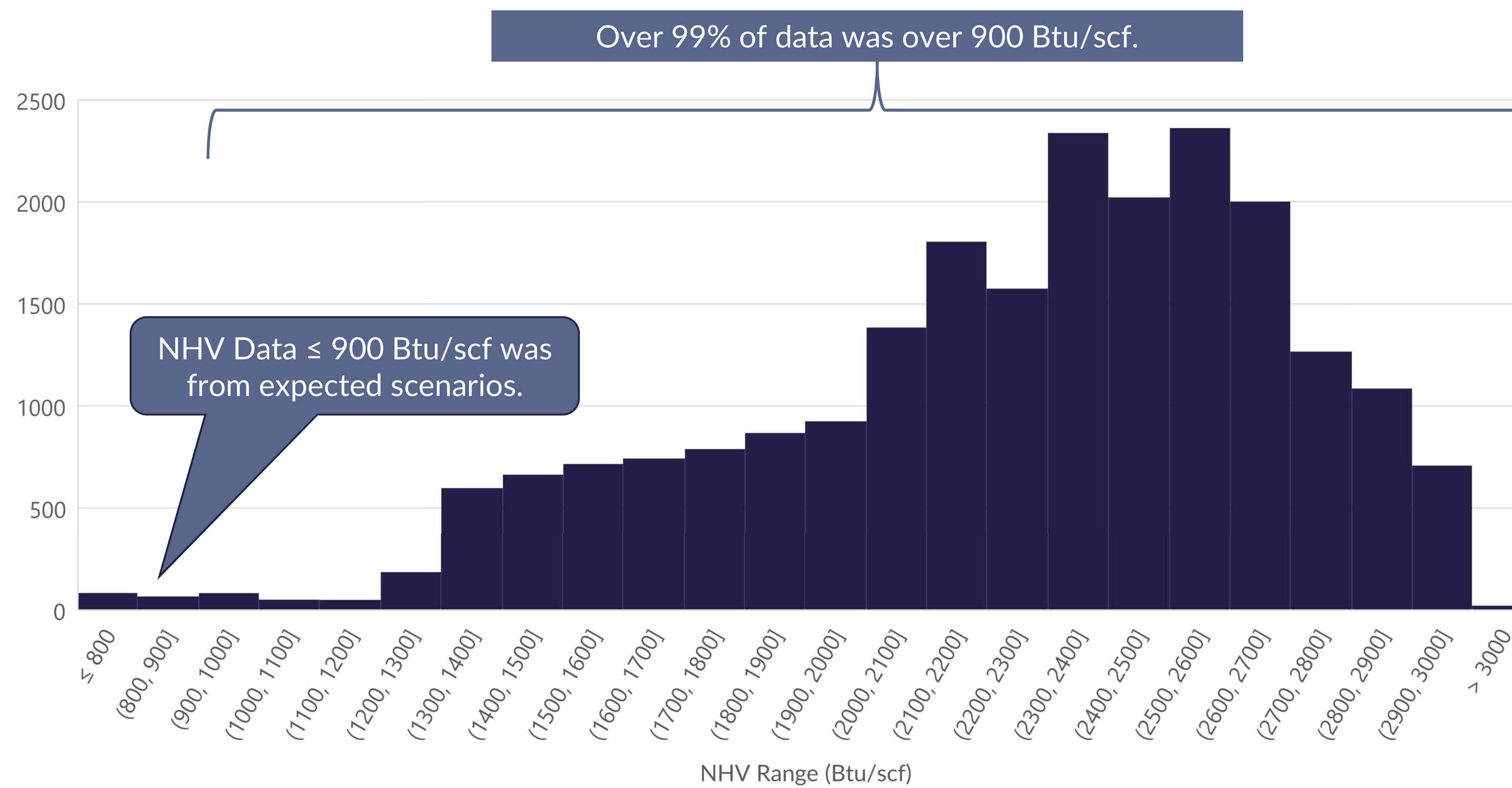
- >99.5% of data ≥ 800 Btu/scf and
- >99.9% of data ≥300 Btu/scf.
- Results appear consistent across basins.
- While some data shows variability, the NHV was above 800 Btu/scf.
- **Survey supports limiting control device NHV monitoring or alternate demonstration requirem to sites where inerts are added.**

NHV Survey – **Results**

Item	LP NHV
lumber of Operators	18
lumber of Basins	12
ata Points	22,396
stimated Sites	4,238
stimated Sources	4,299
verage NHV (Btu/scf)	2,241
ledian NHV (Btu/scf)	2,325
tandard Deviation (Btu/scf)	452
IHV ≥ 800 Btu/scf (%)	99.6%
IHV ≥ 300 Btu/scf (%)	>99.9%
IHV ≥ 200 Btu/scf (%)	>99.9%

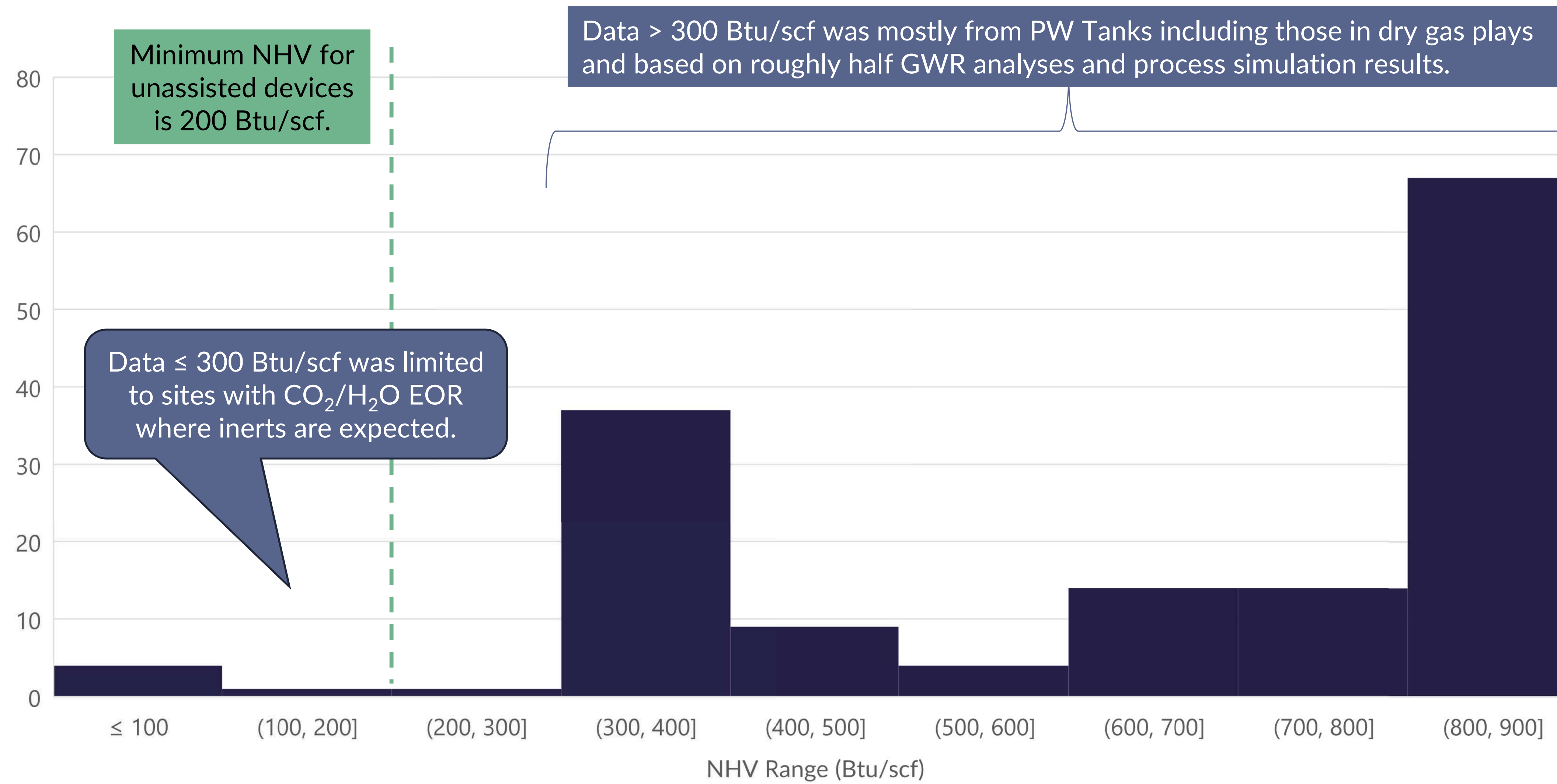
- **95% of data was assessed within the last 3 years.**
- **Basis for NHV**
  - 92% - Compositional Analysis with Process Simulation Results
  - 8% - Compositional Analysis
- **Data Points per Source**
  - Average = 5.2
  - Median = 2
- **99% of Data Cover 5 Basins**
  - Permian = 37%
  - Anadarko = 23%
  - Gulf Coast (Eagleford) = 17%
  - Williston (Bakken) = 12%
  - Powder River = 10%

NHV Survey – LP NHV Data



NHV Survey – LP NHV Data ≤ 900 Btu/scf

xcept for some EOR sites, data was still above the minimum NHV requirement for control devices other than ressure-assisted devices. Given the low vent stream pressure, pressure-assisted devices are unlikely to be used fo ontrol in this situation. In these instances, lower NHV was from anticipated operations.



NHV Survey – LP NHV Results by Basin

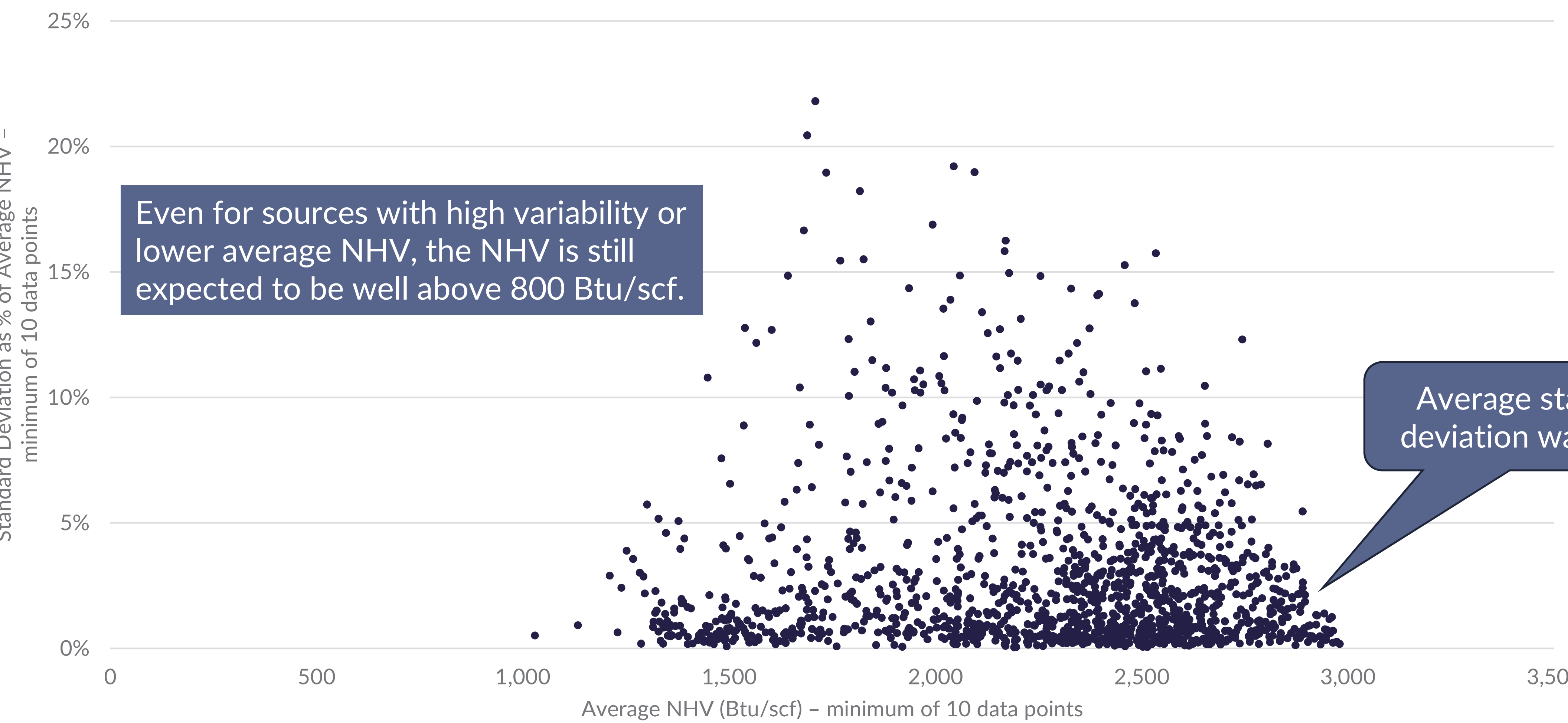
IHV data appears consistent across various basins – generally within a standard deviation of each ther and well above 800 Btu/scf.

	LP NHV						
Basin – AAPG Geologic Province*	Data Points	Average NHV (Btu/scf)	Median NHV (Btu/scf)	Standard Deviation (Btu/scf)	≥ 800 Btu/scf	≥ 300 Btu/scf	≥ 200 Btu/s
rmian Basin (430)	8,211	2,044	2,056	425	99.7%	99.9%	99.
adarko Basin (360)	5,116	2,417	2,412	281	100.0%	100.0%	100.
lf Coast Basin (220)	3,917	2,096	2,112	422	100.0%	100.0%	100.
lliston Basin (395)	2,697	2,477	2,527	241	100.0%	100.0%	100.
wder River Basin (515)	2,133	2,718	2,760	237	100.0%	100.0%	100.
Basins	**22,396**	**2,241**	**2,325**	**452**	**99.6%**	**>99.9%**	**>99.**

ote:
Basins with less than 1,000 data points are not shown individually but are included in “All Basins”.

NHV Survey – LP NHV Variation

- Over 1,400 sources with at least 10 data points were examined for variability.
- While some sources had a standard deviation > 20% of the average NHV, they were well above 800 Btu/scf.



HV Conclusions

ta support a fit-for-purpose approach to NHV demonstration in only the specific scenarios/processes in which re added.

ddition to being unsupported by the data, the final rule's requirements are infeasible.

- Insufficient time to comply
- Insufficient lab/service provider capacity to process sampling for all sites
- Demonstration offramp shares same challenges as the standard
- Sampling/testing equipment not designed to operate in low temperatures or with all types of gas

ommendations

- **Limit NHV demonstration to "inert added" scenarios**
- **Allow 180 days allowed to conduct sampling**
- **Accommodate intermittency by clarifying 1-hour sample can be the collection of 4 15-minute samples**
- **Allow samples to be gathered from a representative point**

Appendix 2

March 19, 2024 Letter from SPL, Inc. to EPA

24 Waterway Ave, Suite 375
The Woodlands, TX 77380
(720)-683-8633

To: Michael S. Regan
EPA Administrator
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Date: March 19th, 2024

Mr. Regan,

On behalf of SPL, Inc and our many customers in the oil and gas industry, I submit this letter to you regarding the recently published 40 CFR Part 60 "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for existing Sources: Oil and Natural Gas Sector Climate Review". I write to provide specific commentary regarding the 60-day compliance mandate § 60.5370b for control devices § 60.5417b(d).

SPL is the largest laboratory in the United States specializing in the analysis of hydrocarbon products, processing more than 225,000 natural gas samples each year. In recent months, we have received countless inquiries from our customers seeking guidance on how to determine the net heating value of their vent gases. Speaking from our direct experience analyzing 1,000s of vent gas samples from every major oil and gas producing region of the United States annually, it would be exceptionally uncommon for the heating value of vent gas to fall below the threshold the EPA has set. Should the EPA not reconsider this requirement, we at SPL believe compliance with the rule as written is possible, but not within the timeframe required to comply. Below, we submit several concerns that the EPA should consider before enforcing any mandate on the oil and gas companies related to this requirement.

- Vent gases are exceptionally heavy gases (relative to air) that are typically depleted with respect to lighter hydrocarbon molecules such as methane and ethane, and enriched in molecules like propane, butane and pentane. As a result, these heavy gases have a lower vapor pressure (relative to a methane-enriched sales gas for example) and therefore don't "flash" from the liquid hydrocarbon stream until the final stage of separation. Whereas the net heating value of methane is 909.4 Btu/ft^3, the net heating value of propane, n-butane and n-pentane is 2,315 Btu/ft^3, 3,000 Btu/ft^3 and 3,707 Btu/ft^3 respectively (source: GPA 2145). Therefore, unless there is a source of inert gas diluting the vent gas stream (sources of inert gas could be added by design, or, due to leaking equipment), there should be no compositional reason the net heating value of that gas would be under the threshold set by the EPA. Speaking directly to SPL's experience, any vent gas sample falling below the EPA's threshold would have been significantly diluted by an inert gas.

- The amount of additional natural gas samples this requirement will result in is vastly greater than the capacity that laboratories have to collect and process such samples in the 60-day window. For example, a producer with 70 devices subject to net heating value determination would mean that they will produce 1960 samples in a 14-day period (assuming each location has both a high- and low-pressure flare). This testing increase from one customer alone, when considered with the volumes generated in the 60-day period nationally, would far exceed the analytical capacities of US laboratories performing the analysis. For SPL specifically, 1960 samples in 14 days would exceed the monthly throughput of most of our regional laboratories. There are not enough gas chromatographs, sample cylinders, and human resources to make compliance within 60-days a possibility.

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- The EPA is requiring “the minimum time of collection for each individual sample be at least one hour”. This requirement goes against the traditional norms for the collection of natural gas samples and therefore will require all sampling entities to deploy alternative strategies that are not widely available at the moment. Proper sample collection techniques are paramount to ensure a representative sample is analyzed by the laboratory. Typical methods for the collection of natural gas samples call for spot sampling techniques that procure gas on very short (seconds to minutes) timescales. The one-hour requirement set forth in the regulation will require the composite sampling techniques typically used in custody-transfer applications (and elsewhere) to be adapted to a more rugged and transportable set up to meet compliance. Again, this requirement can be achieved, but not within the current scope of 60 days. Alternatively, sample collection methods such as those referenced in GPA 2166-22 should be considered permissible by the EPA to eliminate this bottleneck all together.

- The description of the sample canister provided in the regulation suggests the EPA will require Summa Canisters for vent gas collection. Summa canisters present several logistical hurdles that make compliance with § 60.5417b(d) difficult because they are expensive, large, and are not designed for applications such this. Summa cannisters were designed primarily for atmospheric gas sampling. In order to collect 1-hour samples by summa cannister, restrictive flow metering devices will be required. These devices primarily rely on restrictive orifice to meter the gas into the summa cannister. The potentially wet and dirty nature of flare gas will rapidly foul these devices resulting in errors in collection and potential contamination bias. Instead, for operators and laboratories to meet sample demand in a reasonable manner, single cavity stainless steel constant volume cylinders should be allowed for sample collection so long as they are maintained according to the requirements set forth in 43 CFR 3175 (Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas).

- The analytical method for the compositional analysis of vent gas samples, ASTM D1945, from which net heating value is then calculated, is not widely available. The industry standard for determination of heating value is GPA 2261, however, we understand that certain components of the natural gas the EPA desires, including helium, oxygen and hydrogen, are not standard components of GPA 2261 analyses. Therefore, laboratories across the US will require additional time for method development of ASTM D1945 to have the capacity readily available to our customers. Part of this method development may require additional equipment and/or modification for existing equipment that cannot be achieved in the 60-day timeframe.

SPL supports the efforts of the administration to curb GHG as it is a common goal shared with the oil and gas industry. However, we urge the EPA to extend the time for compliance past the current 60-day period and to alter the sampling techniques to the more applicable industry standards set forth by GPA Midstream and the American Petroleum Institute.

Sincerely,

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