October 2, 2023

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U.S. Environmental Protection Agency
EPA Docket Center
Attention: Docket ID No. EPA-HQ-OAR-2023-0234
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Proposed Rule, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determination for Petroleum and Natural Gas Systems," 88 Fed. Reg. 50,282 (Aug. 1, 2023), Docket ID No. EPA-HQ-OAR-2023-0234

Dear Docket Clerk,

Thank you for the opportunity for GPA Midstream Association ("GPA Midstream" or "GPA") to provide comments to the U.S. Environmental Protection Agency's ("EPA" or the "Agency") proposed rule entitled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determination for Petroleum and Natural Gas Systems." 88 Fed. Reg. 50,282 (Aug. 1, 2023).

GPA Midstream has served the U.S. energy industry since 1921 and represents over 50 domestic corporate members that directly employ 55,000 employees that are engaged in the gathering, transportation, processing, treating, storage, and marketing of natural gas, natural gas liquids, crude oil and refined products, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 400,000 jobs across the U.S. economy. In 2022, GPA Midstream members operated over 250,000 miles of gas pipelines, gathered over 85 billion cubic feet per day of natural gas, and operated over 375 natural gas processing facilities that delivered pipeline quality gas into markets across a majority of the U.S. interstate and intrastate pipeline systems.

Since the initial development of the Greenhouse Gas Reporting Program ("GHGRP") in 2009, GPA has participated in every rulemaking related to Subpart C "General Stationary Fuel Combustion Sources" and Subpart W "Petroleum and Natural Gas Systems." In the proposed rule, EPA proposes to revise Subpart W and says that it is doing so to account for total methane emissions through the inclusion of new emission sources, to improve the accuracy of calculated methane emissions using empirical data through new and revised emission calculation methodologies, and to enhance the verification and transparency through increased granularity in emissions reporting. While GPA understands that EPA has a congressional mandate to revise Subpart W, EPA must fully acknowledge that these proposed changes will have significant financial implications to GPA members due to new monitoring and reporting requirements, the impact of newly reported methane emissions on the Inflation Reduction Act's waste emissions charge, and the potentially illogical decisions operators would be forced to make to reduce reported emissions (such as spending huge amounts of money to comply with a refinery rule). This goes

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beyond Congress's direction that EPA revise Subpart W to ensure that any fees imposed under the Inflation Reduction Act be based on empirical data and accurately reflect methane and waste emissions.

For over a decade, GPA has worked in earnest with EPA to streamline and clarify the requirements of the GHGRP to lessen the burden and impact on reporters while still striving to report accurate emissions data, and GPA has appreciated EPA's efforts to work with us. While GPA supports many portions of the proposed rule, we also find that there are unfortunately several elements of the proposal in which EPA has seemingly disregarded prior industry comments and narrowly focused on addressing comments from other stakeholders who are not burdened with reporting under the GHGRP. More extensive comments are provided in this letter, but to highlight our key areas of concern the following summary is provided:

- **Reporting of Combustion Emissions** – EPA has inexplicably retained reporting of combustion emissions under Subpart W <u>while all other industries</u> report these exact same emissions under Subpart C.

- **Default Flare Destruction Removal Efficiency ("DRE")** – EPA proposes to change the default flare DRE to 92 percent, which is a massive change from the current DRE of 98 percent and will result in severe hardship to reporters. This proposed change is based on only a single limited study that used remote sensing technology. These proposed changes ignore decades of EPA's own research and other scientific evidence that justify a minimum 98 percent DRE. This proposed change would also create a paradox of compliance because other rules and permits allow much higher DREs.

- **Use of Empirical Data** – EPA has accommodated use and incorporation of empirical data for some, but not all, emission source categories, in direct conflict with Congress's explicit direction that emissions reported under Subpart W be based on empirical data. EPA needs to allow the use of <u>any</u> relevant empirical data, such as engine stack tests and flare performance tests, and should not pick and choose where empirical data may be used. Further, EPA should not introduce requirements that are completely untethered to real-world data, such as the proposed "undetected leaks" factor that forces reporters to report phantom emissions.

- **Alignment with Other Federal Regulations** – EPA has attempted but failed to properly incorporate requirements from other federal regulations. This is most notable with the "Other Large Release Events" source category, which provides an avenue to circumvent the requirements of EPA's proposed "Super Emitter Response Program" ("SERP") under the Clean Air Act's ("CAA") new source performance standards provisions and is misaligned with the incident reporting thresholds of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Further misalignment can be found with additional requirements for compressor vent measurements and flare requirements. GPA notes that methane reduction and reporting requirements have been proposed or are being contemplated across many federal agencies and departments. Inconsistency between these requirements will simply be untenable for operators and will not support data transparency.

Subpart W should be the "source of truth" for venting, fugitive, and flaring methane emissions accounting. This can be accomplished only if: (1) there is robust coordination within and between federal agencies to ensure consistent requirements; (2) Subpart W is technology agnostic and does not disincentivize or otherwise preclude advancement of emission detection/reduction technologies due to overly specific requirements; and (3) Subpart W has built-in flexibility that allows reporters to incorporate all relevant empirical data.

Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments do not necessarily reflect the importance of a particular comment to GPA and its members. GPA believes all of its comments will help ensure the GHGRP's integrity and deserve serious consideration.

We hope EPA finds the enclosed information useful. GPA welcomes the opportunity to continue discussions with the Agency as it develops its revisions to Subpart W of the GHGRP and implements the waste emissions charge.

Respectfully submitted,

Matthew Hite

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Contents

General Comments

1. The extremely short comment period limits our ability to fully understand and meaningfully comment on the proposal.

GPA has endeavored to create a technically sound and robust set of comments to assist EPA in this rulemaking process. We must express profound unease, however, regarding the limited and unreasonable timeframe provided for public comment for what is undeniably a substantial and complex set of revisions to an already complicated rule. Given the technical intricacies and far-reaching implications of the proposed amendments, it is imperative that all stakeholders have adequate time to comprehensively evaluate the potential impacts and offer meaningful feedback.

In response to our requests for a comment extension,[1] EPA cited the "pre-Federal Register publication version of the notice on the EPA website on July 6, 2023," and mentioned that the "total amount of time for review of the notice amounts to 88 days."[2] This response ignores, however, the important fact that this review period overlapped with another GHGRP proposal, to which GPA submitted substantial and data-rich comments on July 21.[3] This simultaneous timeline posed challenges in allocating adequate resources and focus to both proposals, potentially compromising the depth of our review. The decision to deny an extension now raises deep concerns, particularly when the proposed rule carries significant financial implications for reporting entities.

The intricacy of Subpart W necessitates a thorough and rigorous technical review, which requires ample time for stakeholders to:

- Carefully analyze the proposed changes and their implications on greenhouse gas reporting.
- Engage with technical experts within their organizations or consult with external experts.
- Consider the practical feasibility and implications of the proposed revisions on their operations and reporting practices.
- Collect and compile relevant data and evidence to support their comments.
- Collaborate and coordinate with other stakeholders to ensure a well-informed and balanced perspective.

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[1] GPA, Request for Extension of Comment Period, Docket ID No. EPA-HQ-OAR-2023-0234-0208 (July 13, 2023); GPA, Request for Extension of Comment Period, Docket ID No. EPA-HQ-OAR-2023-0234-0184 (Aug. 4, 2023).

[2] Letter from S. Lie, Director, Climate Change Division, EPA, to M. Hite, GPA Vice President of Government Affairs, Docket ID No. EPA-HQ-OAR-2023-0234-0204 (Aug. 15, 2023); Letter from S. Lie, Director, Climate Change Division, EPA, to M. Hite, GPA Vice President of Government Affairs, Docket ID No. EPA-HQ-OAR-2023-0234-0216 (Aug. 30, 2023).

[3] In addition to GHGRP comment efforts, during this same period of time, GPA members also prepared comments on EPA's proposed revisions to Subpart JJJJ of the New Source Performance Standards ("NSPS") and to Subpart ZZZZ of the National Emission Standards for Hazardous Air Pollutants ("NESHAP"). GPA Comments Re: 88 Fed. Reg. 41,361 (June 26, 2023) National Emission Standards for Hazardous Air Pollutants: Reciprocating Internal Combustion Engines and New Source Performance Standards: Internal Combustion engines; Electronic Reporting, Docket ID No. EPA-HQ-OAR-2022-0879-0043 (Aug. 25, 2023). At the same time, GPA members also submitted comments on a proposed rule issued by PHMSA. GPA Comments on Pipeline Safety: Gas Pipeline Leak Detection and Repair, Docket ID No. PHMSA-2021-0039-26350 (Aug. 16, 2023).

GPA also notes that EPA included at least 77[4] discrete requests for comment in the rule preamble. A 60-day comment period, in this context, is simply inadequate and limits the opportunity for stakeholders to provide well-considered, evidence-based responses to those requests and other related comments (even considering the time between the proposal's release and publication in the Federal Register). Courts have said that Congress intended the Administrative Procedure Act's requirement[5] to provide notice and comment "(1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review."[6] The comment period for the proposed rule does not meet this legal standard because it fails to provide for meaningful participation. Moreover, it may inadvertently hinder the achievement of EPA's goals. As such, EPA should fairly consider additional materials and information provided after the close of the comment period.

2. EPA is subject to section 136 of the CAA in conducting this rulemaking, which constrains its authority.

In the Inflation Reduction Act, Congress established the "Methane emissions and waste reduction incentive program for petroleum and natural gas systems," which it codified as section 136 of the CAA.[7] EPA claims that section 136 provides it with "newly established authority."[8] As EPA acknowledges, this rulemaking directly responds to the mandate from Congress in CAA section 136(h) that EPA revise Subpart W.[9] Congress was very explicit in section 136(h) regarding the scope of EPA's revision of Subpart W. Specifically, Congress expressly stated that the purpose of this revision is to ensure that charges for methane emissions in excess of a congressionally established waste emissions threshold "are [(1)] based on empirical data, … [(2)] accurately reflect the total methane emissions and waste emissions from the applicable facilities, and [(3)] allow owners and operators of applicable facilities to submit empirical emissions data … to demonstrate the extent to which a charge … is owed."[10] EPA's authority in this rulemaking is thus constrained to fulfilling this purpose and anything outside this limited scope runs afoul of Congress's clear directive and the plain language of section 136(h) of the CAA.

To attempt to broaden its authority in this rulemaking, EPA also says it is relying on section 114(a)(1) of the CAA. EPA says this provision provides it with "broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions."[11] But EPA's authority to collect information under section 114 is specifically circumscribed. Under that provision, the Administrator may require the submission of information "[f]or the purpose … of developing or assisting in the development of any implementation plan under"

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[4] Number of times each of these phrases appear in the preamble: "request comment" (38), "seek comment" (2), "seek information" (1), and "seeking comment" (37).

[5] The Administrative Procedure Act applies to this rulemaking because a rulemaking of this type is not one of the specified rulemakings listed under section 307(d) of the CAA. *See* CAA § 307(d), 42 U.S.C. § 7607(d).

[6] *Prometheus Radio Project v. FCC*, 652 F.3d 431, 449 (3d Cir. 2011); *accord Idaho Farm Bureau Fed'n v. Babbitt*, 58 F.3d 1392, 1404 (9th Cir. 1995) ("The purpose of the notice and comment requirement is to provide for meaningful public participation in the rule-making process.").

[7] Pub. L. No. 117-169, Title VI, § 60113, 136 Stat. 2073 (Aug. 16, 2022).

[8] 88 Fed. Reg. at 50,285.

[9] *Id.* at 50,284 ("EPA is proposing revisions to Subpart W consistent with the authority and directives set forth in CAA section 136(h)….").

[10] CAA § 136(h), 42 U.S.C. § 7436(h).

[11] 88 Fed. Reg. at 50,285.

sections 110 or 111(d) of the CAA, any standard of performance under section 111, any emission standard under section 112, regulations related to solid waste, or for purposes "of determining whether any person is in violation of any such standard or requirement of such a plan."[12] None of these purposes apply to the GHGRP, and EPA appropriately does not rely on any of these provisions. Rather, EPA relies on the catch-all provision at the end of section 114(a)(1) that further authorizes the collection of information for the purpose of carrying out any provision of the CAA (with the exception of those portions of Title II of the CAA that apply to a manufacturer of new motor vehicles or their engines).[13]

But, prior to the promulgation of the GHGRP, EPA had never used the catch-all provision of section 114(a)(1) to require the indefinite, if not permanent, gathering and reporting of data. As GPA has pointed out previously, GPA "remains concerned that EPA has not explained, consistent with the limits on the agency's section 114 authority, … the information EPA needs to ensure compliance with rules it has already promulgated" and EPA's primary focus in rulemakings involving the GHGRP should be "tailoring reporting requirements to what is needed to determine whether any source is in violation of an applicable standard."[14] The enactment of section 136(h) now provides the answer to that question. Namely, EPA must tailor the reporting requirements of Subpart W to ensure that any charges under the methane emissions and waste reduction incentive program be "based on empirical data, … accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data … to demonstrate the extent to which a charge … is owed."[15] Anything beyond this limited purpose established by Congress exceeds EPA's authority under the CAA.

3. The proposed changes to Subpart W cannot be properly assessed independently of the Waste Emissions Charge.

EPA states that it "intends to undertake one or more separate actions in the future to implement the waste emissions charge" and as a result, it believes "implementation of the waste emissions charge is outside the scope of this rulemaking."[16] This position does not make sense. The revisions to Subpart W (the subject of this rulemaking) are intertwined with the waste emissions charge and commenting independently is problematic. Indeed, section 136(h), which directs EPA to undergo this rulemaking to revise Subpart W, references *both* "the reporting under [Subpart W], *and calculation of charges under subsections (e) and (f)*."[17] These two provisions go hand in hand, and separating this rulemaking on the revision of Subpart W from the rulemaking on the implementation of the waste emissions charge creates an artificial barrier that Congress did not intend. At a minimum, EPA should consider any comments made in this rulemaking that involve the waste emissions charge that are tied to the proposed revisions to Subpart W. To do otherwise would be arbitrary and capricious.

GPA also urges EPA to reopen the comment period for this proposal following the publication of any proposed rules related to implementing the waste emission charge.

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[12] CAA § 114(a), 42 U.S.C. § 7414(a).
[13] *Id.*; *see also* 88 Fed. Reg. at 50,285-86.
[14] GPA, Comments on EPA's Proposed Rulemaking "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" at 8 (Oct. 6, 2022), Doc. ID No. EPA-HQ-OAR-2019-0424-0192 ("GPA Comments on 2022 Proposed Rule") (attached hereto as Attachment A and incorporated by reference).
[15] CAA § 136(h), 42 U.S.C. § 7436(h).
[16] 88 Fed. Reg. at 50,286.
[17] CAA § 136(h), 42 U.S.C. § 7436(h) (emphasis added).

4. EPA needs to consider revising the definition of "facility" to align with the Inflation Reduction Act.

EPA needs to consider the interaction between the Inflation Reduction Act, the GHGRP, and proposed NSPS OOOOb ("NSPS OOOOb") and proposed Emission Guideline OOOOc ("EG OOOOc").[18] All of these programs involve a definition of "facility" that differs in scope from, and that do not necessarily align with, the public's common understanding of that word. In NSPS OOOOb and EG OOOOc, the "affected facility" is an individual piece of equipment (or group of equipment) such as all the natural gas-driven pneumatic controllers at a gas plant. In the GHGRP, a Subpart W "facility" includes all emissions of the same type (e.g., all gathering and boosting sources) within a basin. A basin is a large geographical area spanning many counties and sometimes multiple states. Neither of these definitions work in the context of the Inflation Reduction Act, nor are they consistent with the general understanding of the word "facility."

The Inflation Reduction Act states that "the term 'applicable facility' means a facility within the following industry segments…."[19] GPA suggests that EPA use the simplest interpretation of the term, which is that a "facility" is a single site, and not specific pieces of equipment within that site or the aggregation of hundreds of sites within a geographical area. GPA believes that this is a straightforward approach that bridges the gap between how the term is used in NSPS OOOOb and EG OOOOc and how the term is used in Subpart W. As the Supreme Court has noted, it is a "fundamental principle of statutory construction (and, indeed, of language itself) that the meaning of a word cannot be determined in isolation but must be drawn from the context in which it is used."[20]

To illustrate this point, current Subpart W requirements address throughput differently depending on each industry segment. This has significant ramifications for implementation of the waste charge provisions of the Inflation Reduction Act, particularly if "facility" is not defined specifically for purposes of the waste emission charge. For instance, under current Subpart W requirements, the gas through each transmission compressor station is reported on a per-transmission-compressor-station basis (98.236(aa)(4)(i)). This accounts for the same gas moving through multiple compressor stations. But then just upstream of transmission, Subpart W requires reporting only of the volumes into and out of a gathering and boosting basin (98.233(aa)(10)(i)-(iv)).[21] Reporting throughput at the gathering and boosting basin boundaries does not adequately capture "intra-basin" movement (e.g., natural gas that moves through multiple gathering and boosting compressor stations within a single basin). Because emissions generated from a facility are a function of the facility throughput, this is a significant disparity. EPA should address this disparity by modifying or adding Subpart W throughput reporting elements for gathering and boosting that allow reporters to align with other industry segments and reflect true facility throughput for assessment against the waste charge.[22] EPA has proposed additional reporting

[18] EPA proposed NSPS OOOOb and EG OOOOc under section 111(b) and section 111(d), respectively, of the CAA. *See* 87 Fed. Reg. 74,702 (Dec. 6, 2022) (supplemental proposed rule); 86 Fed. Reg. 63,110 (Nov. 15, 2021) (partial proposed rule). NSPS OOOOb would apply to new, modified, and reconstructed sources in the oil and gas source category, while EG OOOOc sets forth guidelines for state plans that, once adopted and approved, will apply to existing sources within that category.
[19] Pub. L. No. 117-169, § 30114 (adding new CAA § 136).
[20] *Deal v. United States*, 508 U.S. 129, 132 (1993).
[21] In this proposal, EPA improves the throughput reporting requirements, but the changes fall short of clearly accounting for intra-basin throughput.
[22] *See* GPA Comments on 2022 Proposed Rule; GPA, Comments on EPA's Request for Information on the "Methane Emissions Reduction Program" at 6 (Jan. 18, 2023), Doc. ID No. EPA-HQ-OAR-2022-0875-0054 ("GPA Comments on Methane Emissions Reduction Program") (attached hereto as Attachment B and incorporated by reference).

requirements for each "gathering and boosting site located in the facility," meaning each gathering compressor station, centralized oil production site, gathering pipeline, or other fence-line site.[23] In addition to the identification data that EPA has proposed be reported, throughput data should be reported per site as well. The overall throughput for the gathering and boosting "facility" should be revised to be equal to the sum of all individual "site" throughputs. Comment 85 provides additional comment on the definition of the term throughput.

5. GPA reiterates and reincorporates all of its comments on the 2022 Proposed Rule.

GPA submitted expansive comments on the 2022 Proposed Rule and also submitted comments to the pre-proposal rulemaking docket on the Methane Emissions Reduction Program.[24] The 2022 Proposed Rule was released prior to the enactment of the Inflation Reduction Act and the directive from Congress to revise Subpart W.[25] In its comments on the 2022 Proposed Rule, GPA asked that EPA not finalize that proposal but instead "issue one comprehensive subpart W rule package."[26] GPA appreciates that EPA has clearly stated that it "does not intend to finalize the revisions to subpart W that were in the 2022 Proposed Rule."[27] Unfortunately, even though EPA says it "considered … the concerns and information submitted by commenters in response to" the 2022 Proposed Rule in developing this proposed rule,[28] EPA did not release a response to comments document or provide any reaction to the comments in the preamble to this proposed rule. As a result, commenters on the 2022 Proposed Rule, including GPA, do not have a clear indication of what EPA's thinking was in response to those comments.

EPA notes that "[c]ommenters who would like the EPA to further consider in this rulemaking any relevant comments that they provided on the 2022 Proposed Rule … must resubmit those comments to the EPA during this proposal's comment period."[29] GPA is resubmitting its comments on the 2022 Proposed Rule in their entirety; those comments are included here as Attachment A and incorporated by reference. Similarly, GPA is also resubmitting its 2023 pre-proposal comments on the Methane Emission Reduction Program in their entirety; those comments are included here as Attachment B and incorporated by reference. GPA reiterates the comments that it made in these two prior sets of comments and expects a response from EPA to the points made therein.[30]

6. The GHGRP serves an informational purpose only—to report emissions—and it cannot be used to mandate control or reduction of greenhouse gas emissions.

The GHGRP serves an informational purpose only—the reporting of greenhouse gas emissions from certain sources. Indeed, when the rule was initially promulgated in 2009, EPA explicitly stated that "[t]he rule does not require control of greenhouse gases, rather it requires only that sources above certain

[23] Proposed 40 C.F.R. § 98.236(aa)(10)(v).
[24] *See* GPA Comments on 2022 Proposed Rule; GPA Comments on Methane Emissions Reduction Program.
[25] 88 Fed. Reg. at 50,285.
[26] GPA Comments on 2022 Proposed Rule at 3.
[27] 88 Fed. Reg. at 50,285.
[28] *Id.*
[29] *Id.*
[30] The Supreme Court has held that "[a]n agency must consider and respond to significant comments received during the period for public comment." *Perez v. Mortgage Bankers Ass'n*, 135 S. Ct. 1199, 1203 (2015). The Ninth Circuit has described "significant comments" as "those which raise relevant points and which, if adopted, would require a change in the agency's proposed rule." *American Mining Congress v. EPA*, 965 F.2d 759, 771 (9th Cir. 1992). At a minimum, GPA expects a response to all of the comments it made that requested changes to the proposed rules.

threshold levels monitor and report emissions."[31] While GPA supports the reduction of methane emissions, any emission reduction or control requirements must be imposed under other provisions of the CAA, such as the NSPS and emission guidelines under section 111.

Unfortunately, some provisions of the proposed rule stray unlawfully into the territory of emission regulation, and these provisions should not be finalized. Many of the provisions are appropriately proposed as part of EPA's proposed NSPS OOOOb and EG OOOOc rulemaking and should not give rise to additional requirements in Subpart W. Examples of this include EPA requesting comment on the need to establish additional requirements for third-party notifiers and the verification of third-party notifications.[32] EPA requested comment on this issue in the NSPS OOOOb and EG OOOOc rulemaking;[33] it should not repeat that here. Nor should there be requirements as part of this informational reporting rule on reporting "[t]he total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year,"[34] flare pilot monitoring,[35] or tank thief hatch inspections.[36] Finally, aspects of this proposal (such as proposed requirements related to flare DRE) could impact air permitting. Subpart W—a greenhouse gas reporting rule—should not be the driver on how to permit criteria and hazardous air pollutant emissions.

7. GPA generally supports EPA's interpretation of what constitutes "empirical data" but additional options to use empirical data must be included.

In the proposed rule, EPA notes that "[t]here are many forms of empirical data that can be used to quantify [greenhouse gas ("GHG")] emissions" and that for the purposes of its revision of Subpart W, it "interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to calculate emissions at a facility, including direct emissions measurements, monitoring of [methane] emissions (*e.g.*, leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data."[37] As a general matter, GPA supports EPA's interpretation. In particular, GPA supports EPA's proposal to include emission factors in Subpart W where appropriate, and not mandating direct measurement of every emission source, but optionally "allow[ing] for the development of site-specific emission factors for equipment leaks and pneumatic devices based on data collected from direct measurement at the facility."[38] As discussed further in in the comments listed below, however, EPA misses many opportunities to incorporate additional pertinent empirical data. Per the mandate of the IRA, EPA must include additional options to determine emissions using this data, including cases where direct measurement should be allowed, cases where emission factors should be allowed, and cases where other data should be allowed to determine emission duration/cessation such as:

- Allow large release event duration to be assessed by more than "monitored process parameters" or "monitoring or measurement survey"; for example, operator inspection logs should be an accepted credible limit on large release event duration [Comment 19]

[31] 74 Fed. Reg. 56,260 (Oct. 30, 2009).
[32] 88 Fed. Reg. at 50,300.
[33] *See* 87 Fed. Reg. 74,702, 74,750 (Dec. 6, 2022).
[34] 88 Fed. Reg. at 50,419.
[35] *Id.* at 50,429.
[36] *Id.* at 50,326.
[37] *Id.* at 50,286.
[38] *Id.* at 50,289.

- Allow original equipment manufacturer ("OEM")/manufacturer specification data for natural gas driven pneumatic devices and pumps [Comment 24]
- Allow reporters to demonstrate some capture efficiency for open or not properly seated tank thief hatches [Comment 42]
- Allow demonstration of thief hatch emission repair [Comment 43]
- Allow tank pressure sensors to determine if a thief hatch is open [Comment 45]
- Allow manufacturer guarantees or test data for flare destruction efficiency [Comments 53 and 61]
- Eliminate the "undetected leak factor" for fugitive component leaks [Comment 66]
- Allow actual gas composition to be used when calculating transmission and underground storage equipment leak emissions [Comment 68]
- Allow operators to account for equipment leak repair [Comment 71]
- Allow direct measurement of engine crankcase emissions [Comment 75]
- Allow use of stack test data for engines combusting field gas [Comment 80]

8. The GHGRP is misaligned with certain other EPA programs.

For sources subject to NSPS OOOOb and EG OOOOc, EPA says "the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." [39] Unfortunately, however, as GPA has noted in its comments, the proposed rule introduces inconsistencies between the two EPA programs, which are listed here:

- Measurement of isolation and blowdown valves leakage for compressors subject to NSPS OOOOb or EG OOOOc. This is discussed further below in Comment 64.
- Proposed NSPS OOOOb identifies optical gas imaging ("OGI") as the best system of emission reduction ("BSER"), but Subpart W OGI emission factors are higher than those for Method 21. This is discussed further below in Comment 67.
- Inconsistencies between measurement requirements for leak surveys under Subpart W and other EPA fugitive component monitoring requirements. This is discussed further below in Comment 70.
- Duplicative reporting requirements for super emitter events and notifications. This is discussed further below in Comment 17.

[39] *Id.* at 50,288.

9. **EPA should provide XML schema and revised reporting forms no later than October 31, 2024.**

GPA strongly encourages EPA to provide the draft XML schema and draft revised reporting forms to reporters for review and testing as early as possible—and not later than October 31, 2024.[40] Providing the draft XML schema and draft revised reporting forms early in the past has led to the identification of errors and resulted in significant improvements. Additionally, final forms and schema should be published at least 6 months prior to the due date of the first affected reports. Many midstream operators are reporting data for hundreds of assets and have thus developed automated processes for populating forms and/or schema, which will need to be updated to reflect the extensive changes EPA has proposed. On the occasions where EPA has not released schema until late January,[41] i.e., mere weeks before the reporting deadline, this has compounded challenges during the demanding annual reporting process, and GPA urges EPA to release the schema as early as possible.

10. **EPA must limit reporting elements only to those data required to verify emissions.**

Reporting under this rule is an enormous annual effort. GPA recognizes the value in reporting GHG emissions and the need for certain information to verify those emissions. In many places, however, EPA adds unnecessary math in a reporting element. For example, 98.236(e)(3)(ii)(A) askes for "*The total number of opened desiccant dehydrators* [98.236(e)(3)(ii)(A)]." This is <u>not</u> an input into an equation. This requirement seems to exist solely to see if reporters can add two other reporting elements together ("*The number of opened desiccant dehydrators that used deliquescing desiccant* [98.236(e)(3)(ii)(B)]" and "*The number of opened desiccant dehydrators that used regenerative desiccant*" [98.233(e)(3)(ii)(C)]). EPA should eliminate these extraneous reporting elements that are duplicative of other data it is already collecting and that simply add steps to reporters without any additional information to be gained.

11. **EPA should grant automatic use of Best Available Monitoring Methods ("BAMM") for reporting year 2025.**

EPA's proposed changes to the GHGRP are extensive and will require substantial modifications to data collection and reporting systems. Additionally, EPA has proposed requirements that may necessitate the installation of flow meters (see Comments 35, 56, and 84). GPA strongly urges EPA to eliminate any requirements that necessitate installation of equipment, but if EPA finalizes these unnecessary requirements, then BAMM will be required. EPA must grant BAMM automatically for RY2025 and by request for RY2026.

Comments in Support of the Proposed Rule

12. **GPA supports many of EPA's proposed changes to the GHGRP.**

GPA has worked extensively with EPA over the years on potential revisions to the GHGRP, and GPA appreciates that a significant number of the changes EPA has proposed reflect approaches consistent with positions for which GPA has advocated technical data and other information GPA has developed and supplied to EPA. GPA is pleased to have been a part of this productive process and encourages EPA

[40] If finalized, the majority of the proposed revisions would become effective on January 1, 2025. *Id*. at 50,365. GPA agrees with this approach because, as discussed in this section, time is needed to develop and implement these new procedures.

[41] *See, e.g.*, EPA, XML Reporting Instructions, https://ccdsupport.com/confluence/display/help/Archived+XML+Reporting+Instructions.

to finalize those provisions, consistent with these comments, that GPA believes will provide for a more effective and efficient GHGRP.

The following is a list of substantive proposed changes that GPA expressly supports.

- Removal of the requirement to measure each compressor in the not-operating-depressurized ("NOD") mode every three years [98.233(o)(1)(i)(C) and (p)(1)(i)(D)];
- Alignment of the onshore natural gas processing definition with NSPS OOOOa through targeted consistency changes [98.230(a)];
- Removal of the 25 million standard cubic feet ("MMscf") per day threshold in the definition of natural gas processing [98.230(a)];
- Streamlining reporting of hydrocarbon liquid throughputs under Subparts W and NN [98.236(aa)(3)];
- Including a new option to survey natural gas intermittent bleed pneumatic devices and calculate emissions based on properly functioning devices and malfunctioning devices [98.233(a)(3)(ii)]; [42]
- Allowing use of calibrated bags and high-volume samplers for centrifugal compressor wet seal oil degassing vent measurements [98.233(o)(2)(ii)];
- Removal of redundant reporting requirements of manifolding/controls at both the compressor and leak/vent level [98.236(o)(1)(vi)-(ix) and 98.236(p)(1)(vi)-(ix)];
- Adding total hydrocarbon leaker emission factors for onshore natural gas processing for Method 21 at 500 ppm [Table W-4];
- Allowing Calculation Method 2 (process simulation) for glycol dehydrators with an annual average daily natural gas throughput that is less than 0.4 MMscf per day [98.233(e)];
- Including ProMax as an example software program for calculating emissions from glycol units [98.233(e)] and atmospheric tanks [98.233(j)];
- Allowing Calculation Method 1 (process simulation) for produced water tanks and for storage tanks with throughputs less than 10 barrels per day [98.233(j)];
- Allowing flared emissions from acid gas removal units ("AGRUs"), nitrogen vents, and glycol dehydrators to be reported under the flare source category [98.233(d), (e)];
- Not finalizing or reproposing additional reporting elements for glycol dehydrators that were proposed in the 2022 Proposed Rule;
- The option to use engineering estimates based on best available data to determine the fuel gas composition, while maintaining the option for reporters to use 98.233(u)(2) [98.233(z)(3)(ii)(B)];
- Allowing calculations and reporting for groups of combustion unit types using the same fuel type and method for determining the CH_4 emission factor; and
- An effective date of January 1, 2025.

[42] See Comment 21 requesting retention of the default emission factor for intermittent bleed controllers.

13. GPA supports the proposed changes to the definition of the Onshore Natural Gas Processing industry segment.

GPA supports the proposed changes to the definition of the Onshore Natural Gas Processing segment [98.230(a)(3)] because these revisions will better categorize facilities to align with industry terminology, which will also better align reported emissions with the appropriate industry segments. For the reasons EPA articulated in the preamble,[43] these changes also add certainty for reporters and reduce burden. This proposed change will result in some facilities reporting under a different segment, but GPA members do not anticipate the proposed changes to the definition will impact reported emissions significantly.

Subpart A

14. The "historic reporting representative" concept is unworkable, and EPA should instead implement a "data freeze."

The requirements in the proposed rule regarding the selection of "a 'historic reporting representative' that would be responsible for revisions to annual GHG reports for previous reporting years within 90 days" of an ownership or operator change at a source are unworkable.[44] There are serious legal issues associated with an individual whose company no longer owns or operates a source amending reports for a facility with which they are no longer connected. This proposed approach also gives rise to issues with confidential business information and goes against the definition of a designated representative under the GHGRP.[45] The new owner should be responsible for updating any past reports—with the recognition that they would be responsible for doing so only to the best of their ability.

Rather than ask an individual to certify changes to a report (for which they are liable for criminal and civil penalties) for a source for which they are no longer associated, EPA should instead endeavor to limit requests to amend previous reports—especially if EPA did not alert the initial reporter to a potential error within six months of the initial report submittal. GPA respectfully suggests that EPA instead implement a data freeze wherein all data in a report would be "frozen" (and thus unable to be revised) once one year passes from the submittal of the report. Especially because obligations under the methane fee program are driven by these reports, continual changes to reports beyond the one-year mark would be add a layer of complexity that would quickly become unwieldy.

Other Large Release Events

GPA supports EPA's overall objective to account for large, episodic releases because the GHGRP can underestimate emissions totals in the absence of these emissions when compared to estimates by other methodologies. If done properly, GPA believes that this change will go a long way to addressing concerns regarding underestimation from the GHGRP and reduce the need to keep multiple "sets of books" on GHG emissions. GPA has identified several issues with the proposed requirements, however, and offers solutions to these issues below.

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[43] 88 Fed. Reg. at 50,294-96.
[44] *See id.* at 50,294.
[45] 40 C.F.R. § 98.4.

15. **The 100 kilograms per hour ("kg/hr") instantaneous emission rate that is proposed in NSPS OOOOb and EG OOOOc as part of the proposed SERP is not appropriate for the GHGRP and has significant detrimental consequences.**

In the proposed rule, EPA proposes to apply the 100 kg/hr CH_4 threshold in the proposed SERP under proposed NSPS OOOOb and EG OOOOc to Subpart W. This proposal is fundamentally flawed, however, as the proposed SERP is intended to serve as a compliance program to drive rapid corrective response to potential emission events. In contrast, the GHGRP is intended to serve as a reporting program to inform EPA of annual GHG emissions. On its own, the instantaneous 100 kg/hr CH_4 threshold is an unjustified metric to quantify total GHG emissions for inventory purposes. It is entirely possible emissions from a 100 kg/hr CH_4 emission event may only last for a very short period of time and result in immaterial GHG emissions. GPA believes that setting a single large event threshold (e.g., 250 metric tons of carbon dioxide equivalent ("CO_2e")[46]) is reflective of EPA's intent to include previously unreported GHG emission events into annual inventories and is the most appropriate course of action for this rulemaking.

As GPA thoroughly explained in our comments on the proposed SERP, there are serious issues with deputizing third parties to act in a compliance enforcement capacity.[47] GPA continues to be very concerned that the NSPS OOOOb and EG OOOOc proposal completely lacks any substantive detail on how such a third-party authorization process would work (which is arbitrary and capricious and does not comport with the CAA). This Subpart W proposal has incorporated all those problems and then made them even worse. The Subpart W proposed requirements provide a back door to circumvent the third-party authorization "proposed"[48] in the SERP. This Subpart W proposal does not attempt to propose such a process or any requirements for third-party notifiers,[49] which only furthers the arbitrary and capricious nature of the SERP program. For example, third parties could overwhelm GHGRP reporters at any time. It is not reasonable for EPA to require GHGRP reporters to address information coming from every third-party without robust structure as to how and when that information is provided to reporters and guardrails around when a third-party report requires a response. Reporters simply cannot be expected to submit complete and accurate reports when it is possible for any third-party to data dump on a reporter on March 30th when annual reports are due on March 31st.

[46] See Comment 16 below for discussion on an appropriate per-event threshold.

[47] GPA Comments on "Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector" (Dec. 6, 2022) ("GPA Comments on NSPS OOOOb and EG OOOOc"), Docket EPA-HQ-OAR-2021-0317 (attached hereto as Attachment C and incorporated by reference).

[48] EPA proposed a general framework of authorizing third parties completely lacking any substantive detail on how such an authorization process would work, including what criteria for authorization would be based on. *See id.* at 14-21.

[49] EPA seeks comment only "on the need to establish additional requirements for third-party notifiers and the verification of third-party notifications." 88 Fed. Reg. at 50,300. The Agency then seeks comment on whether the e-GGRT Help Desk is adequate for supporting this process. *Id.* This is difficult to comment on because EPA does not propose anything, and GPA is unclear what EPA is asking here. As GPA commented on the proposed SERP program, any third-party notifications need to be vetted through a robust process centrally managed by the EPA. Clearly a help desk is not adequate for establishing such processes and procedures.

Further, the 100 kg/hr proposed SERP program does not apply to pipelines.[50,51] As a result, aligning SERP thresholds with Subpart W for pipelines is arbitrary, capricious, and unnecessary. It also has the unfortunate effect of adding complexity and circumventing the applicability of the proposed standards under NSPS OOOOb and EG OOOOc. EPA should remove this requirement from any final rule.

Lastly, proposing to incorporate the SERP into Subpart W might cause an inequitable reporting program. Under EG OOOOc, states have the authority to adopt more stringent standards and could establish a response threshold lower than 100 kg/hr CH_4. This could result in additional emissions being reported and additional waste emission charges being imposed on some reporters. If EPA maintains a need to tie Subpart W to the SERP, reporting under Subpart W should be limited to verified super-emitter events under the SERP and include an "and" designation between the two reporting thresholds to distinguish between the significance of total GHG tonnage.

For these reasons, EPA should eliminate the 100 kg/hr threshold from this source category. Alternatively, at a minimum, EPA should apply both thresholds to indicate the emission event is truly a large release event (i.e., both 100 kg/hr and 250 metric tons ("MT") CO_2e).

16. EPA should apply a more reasonable threshold to describe "Large Events" and distinguish between "Large Events," "Pipeline Events," and "Other Events."

GPA understands that EPA ultimately intends for the Large Event source category to serve as a "catch-all bucket" to report emissions from sources that are not otherwise categorized under Subpart W. As such, GPA is not advocating against the 250 MT CO_2e threshold, but we want to be clear that this quantity is not "large" when considering the total amount of emissions reported by most Subpart W reporters.

Additionally, GPA takes exception with the idea of reporting maintenance events, such as tank cleaning, as "Other Large Release Events." The preamble describes the "Other Large Release Events" category to capture significant emissions events like well blowouts and catastrophic fires.[52] It is misleading to characterize known, planned maintenance emissions as "large events" when other source categories can have emissions totals greater than 250 MT CO_2e (such as running an engine) that are categorized as normal emissions. It is also not appropriate to characterize lower rate leaks as Other Large Release Events. For example, it would take approximately 90 days for a 4.7 kg/hr CH_4 leak to exceed the proposed 250 MT CO_2e threshold. The rule language should be plain. A "large release event" should be just that, not a small release over a long period of time.

GPA does not understand why EPA would intend to characterize maintenance events or low-rate leaks as "Other Large Release Events" and believes this to be a by-product of introducing reporting thresholds into the proposed rule without time limitations. GPA reiterates its previously provided comment to EPA on this issue that a 24-hour period be used to determine applicability to the 250 MT CO_2e threshold. This time period limitation would align with other common state and federal reporting thresholds

[50] Proposed 40 C.F.R. § 60.5365b(j) ("*Each super-emitter affected facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.*").
[51] Proposed 40 C.F.R. § 60.5386c(i) ("*Each super-emitter designated facility, which is any source of emissions located at an individual well site, centralized production facility, or compressor station with emissions detected, using remote detection methods, with a quantified emission rate of 100 kg/hr of methane or greater.*").
[52] 88 Fed. Reg. at 50,296 ("*On the other hand, there have been several large, atypical release events at oil and gas facilities over the last few years where it was difficult to sufficiently include these emissions in annual GHGRP reports.*").

(including Subpart Y, which EPA cites as justification for this threshold[53]) and reduce the burden on reporters by allowing them to align GHG emissions quantifications with other requirements when determining whether release event thresholds are met. If EPA does not incorporate a time boundary to the 250 MT CO_2e threshold and does not combine the instantaneous threshold with the total event threshold, then GPA suggests that the total event threshold be reevaluated. In this instance, a higher threshold of 1,000 MT CO_2e would more appropriately characterize an emission event as "large" and reduce the burden associated with reporting such events.

GPA suggests that EPA retitle this source category as "Other Events" and divide reporting categories as follows: (1) Large Events, (2) Pipeline Events, and (3) Other Events. This would more appropriately characterize emissions from maintenance events and low-rate leaks, while maintaining the reporting of large events associated with a large instantaneous CH_4 emission rate. Additionally, EPA requested comment regarding aligning the Other Large Release Event thresholds with PHMSA requirements,[54] and GPA supports aligning with the PHMSA definition of ''incident'' at 49 C.F.R. § 191.3. Given the unique nature of pipeline emissions and existing federal rules to report pipeline releases, aligning Subpart W with PHMSA requirements is justified. This will significantly reduce the burden on operators by maintaining consistency between the programs. To address the issues described in this and the previous comment (Comment 15), GPA suggests the following:

Source Category (y) Other Events	Applicability	Threshold
(1) Large Events	Unplanned episodic or intermittent emission events not subject to reporting under other paragraphs (e.g., fires, explosions, blowouts, etc.).	Verified "Super Emitter" Under NSPS OOOOb or EG OOOOc (Note: GPA suggests removing instantaneous 100 kg/hr CH_4 threshold altogether) **AND** 250 MT CO_2e released within 24-hours
(2) Pipeline Events	Pipelines regulated under Title 49, Chapter 1	3 MMscf
(3) Other Events	Planned periodic emission events not subject to reporting under other paragraphs (e.g., maintenance events, tank cleaning, etc.) For sources subject to reporting under other paragraphs, report emissions in excess of emissions calculated under Subpart W.	250 MT CO_2e

[53] *Id.* at 50,298.
[54] *Id.* at 50,299.

17. Reporting requirements duplicative of NSPS OOOOb and EG OOOOc must be deleted.

In proposed section 98.236(y)(11), EPA proposes reporting requirements that are nearly identical to the proposed SERP reporting requirements in NSPS OOOOb and EG OOOOc. It is unclear how this information informs the reporting of emissions that is relevant to the GHGRP. Data reporting elements such as the unique notification identification number under the SERP, latitude/longitude of release, a description of the technology or method used to identify the release, and the total number of super-emitter release notifications received from a third-party for the facility have no bearing or impact on the reporting of GHG emissions. If this information is somehow pertinent to EPA, then GHGRP reporters should not have to bear the burden of retransmitting that information through a separate reporting program as it is already being provided to EPA through the NSPS program.

18. EPA must add definitions for “super-emitter” and “third-party” if it decides to retain them in the final rule.

EPA does not define the term “super-emitter” in the proposed rule, nor does it cross-reference NSPS OOOOb and EG OOOOc to define the term. Proposed 98.236(y)(11)(iv) states that reporters must “[r]eport the total number of super-emitter release notifications received from a third-party,” including:

> An indication of whether the super-emitter release notification was received under the provisions of 40 C.F.R. § 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, or from another third-party. If the notification was received from another third-party, report the following information about the notifier and data received, if known.

The term “super-emitter” either needs to be replaced with “other large release event” or defined.

EPA should also clarify that “third-party” is not intended to include third parties that are hired by the reporter to identify potential emissions (i.e., through a compliance program or voluntarily). To do otherwise would discourage operators from proactively surveying for possible emissions. Operators would still be required to report such detected emissions as applicable under Subpart W but should be exempt from reporting information under proposed 98.236(y)(11)(iv).

19. The proposed 182 day “backstop” and 100 kg/hr threshold are problematic because many of the advanced technologies mentioned in the rule are not deployed by all operators, especially small operators, and because these requirements could drive exceptional costs.

EPA proposes that emissions detected above the proposed thresholds must be assumed to start on either (1) the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the proposed thresholds, or (2) must be assumed to have a duration of 182 days (six months) [98.233(y)(2)(ii)]. EPA also proposes that the definition of “monitoring or measurement survey” include any monitoring or measurement method in 98.234(a) through (d), as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at 100 kg/hr [98.233(y)(2)(iv)].

For gathering system pipeline leaks, these proposed provisions may lead to an untenable environment where operators would be forced to monitor pipelines frequently to create temporal “backstops” on emission events. For example, to avoid the possibility of an emission being assumed to have taken place over a six-month period of time, reporters will need to monitor far more frequently than the proposed rule contemplates to avoid this result. Monitoring is a very expensive endeavor with costs being in the hundreds of thousands or millions of dollars depending on how many sources/miles need to be monitored. The cost for this more frequent, additional monitoring was not assessed by EPA.

In addition to the enormous cost that this additional monitoring will require, with the current state of advanced screening methods, it is unclear if there are enough technology service providers to meet the increased demand, which could unfairly disadvantage some reporters to report larger than actual emissions (because the emissions will be attributed to an arbitrarily assumed duration of six months regardless of whether the emissions actually took place over that period of time), which will lead to increased methane fees. This concern about the availability of technology service providers is already occurring. Some GPA members have already been contacted by their technology service providers with warnings that they will lack capacity to service all of their customers' needs if the monitoring frequency increases, with the providers urging members to sign contracts now to ensure that they will be able to utilize their services.

To alleviate these problems, EPA should consider some or all of the following changes: (1) adjust the thresholds as described above in Comments 15 and 16; (2) minimize the "backstop" as much as possible (30 days at most—182 days is arbitrary and capricious); (3) allow event duration to be assessed by more than "monitored process parameters" or "monitoring or measurement survey"(e.g., operators' inspection logs should be an accepted credible limit on event duration); or (4) in the event EPA retains the instantaneous threshold (which GPA urges EPA not to do), implement a phased-in step-down of the instantaneous threshold to allow technology to be further developed and deployed (e.g., 200 kg/hr initially, then stepping down to 150 kg/hr, and eventually reach 100 kg/hr in the future).[55]

20. EPA must explain how to parse data between the source category and "other large release events" to avoid double-counting emissions.

EPA proposes that if a source is subject to reporting under Subpart W and its emissions exceed the "Other Large Release Events" thresholds, then a reporter "must report the emissions as an other large release event and exclude the emissions from this release in the source-specific emissions" [98.233(y)(1)(ii)]. EPA does not address, however, how this math would work, especially for sources with population emission factors such as pipeline leaks. EPA must address this critical calculation methodology, at a minimum through comprehensive guidance or preferably by incorporating it directly into the rule itself.

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[55] Satellites can survey more frequently, but many current satellite options are limited to greater than 100 kg/hr detection threshold. E.D. Sherwin, et al., "Single-blind test of nine methane-sensing satellite systems from three continents," EarthArXiv, https://eartharxiv.org/repository/view/5605/ (pre-print, version 3) (noting that "*Orbio Earth, Maxar, and GHGSat all detected a 1.19 [1.15, 1.23] t/h emission using Sentinel-2, with errors ranging from -8% to +170%. Orbio Earth detected a 1.05 [0.99, 1.10] t/h emission to within ±47%...The smallest detected emissions for the remaining satellites are 1.10 [1.06, 1.13] t/h for EnMAP, 1.26 [0.26, 2.26] t/h for GF5, 1.39 [1.34, 1.43] t/h for LandSat 8/9, 0.414 [0.410, 0.417] t/h for PRISMA, and 1.03 [0.98, 1.09] t/h for ZY1. GHGSat correctly detected and quantified the only nonzero release for which GHGSat-C collected data and passed quality control, which was 0.401 [0.399, 0.404] t/h…*").

Natural Gas Pneumatic Device Venting

21. EPA should retain population emission factors for intermittent bleed pneumatics.

While GPA supports EPA's proposal to allow surveys for malfunctioning intermittent bleed controllers, it is unreasonable to eliminate the default population count emission factor for intermittent bleed devices while retaining the default emission factors for high and low continuous bleed devices. Although it is presumed that the promulgation of NSPS OOOOb and EG OOOOc will ultimately minimize natural gas driven pneumatic device venting (with exceptions for safety or operational demand) at facilities subject to these regulations, GPA anticipates it will be many years before the EG OOOOc-implementing requirements result in zero-emitting pneumatic devices.

Operators should not be forced into a cumbersome direct measurement requirement for a single type of pneumatic device. GPA believes the removal of the default emission factors and the addition of a monitoring requirement for intermittent bleed pneumatic devices constitutes an overreach within Subpart W. The monitoring requirement for intermittent bleed devices, which mainly serve as a detection method for malfunctioning devices, seemingly mandates an unlawful compliance standard as a part of a rule that simply requires the reporting of emissions. As previously stated in the General Comments section above, any requirements that go beyond reporting into the area of emission reduction or compliance should be addressed in an appropriate NSPS, NESHAP, or other CAA provision—not in a data collection rule.

Additionally, there are intermittent bleed pneumatic controllers on pipelines (such as emergency shutdown valves and valves associated with pigging). These controllers are often remote, scattered across miles of pipeline, and can be difficult to access. These controllers are not subject to NSPS OOOOb and EG OOOOc.[56,57] EPA is therefore incorrect in its assertion that "few" intermittent bleed devices will exist and those that do will be subject to monitoring per NSPS OOOOb and EG OOOOc.[58] GPA members envision needing to use contractors to implement these surveys, and the remote nature of these valves would add significant expense and burden. Retaining the emission factors for these controllers would ease this expense and burden.

22. Any survey requirements must be adjusted for devices outside of a fence-line.

It is unclear how pneumatic devices located along the pipeline but not at a fence-line site[59] should be monitored. It is not reasonable to mandate monitoring for all intermittent pneumatics within a basin but

[56] Proposed 40 C.F.R. § 60.5365b(d) ("Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers <u>at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station</u>. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records in §60.5420b(c)(6)(i)(A) or (B) are maintained, as applicable.") (emphasis added).

[57] *Id.* § 60.5386c(d) ("Each pneumatic controller designated facility, which is the collection of natural gas-driven pneumatic controllers <u>at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station</u>. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the designated facility, provided that the records in §60.5420c(c)(5)(i)(A) or (B) are maintained, as applicable.") (emphasis added).

[58] 88 Fed. Reg. at 50,312.

[59] Proposed 40 C.F.R. § 98.238 ("*Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within the onshore petroleum and natural gas gathering and boosting industry segment.*").

outside a fence-line in a single year. As noted above in Comment 21, these devices are geographically dispersed. Further, because of the shifting landscape of natural gas pneumatic controllers, it is not practical for EPA to mandate monitoring "approximately the same number of devices each year." GPA suggests the following changes to the proposed regulatory text:

> *98.233(a)(3)(ii)(B) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you must monitor all natural gas intermittent bleed pneumatic devices at your facility at least once every 5 years.* ~~*If you elect to monitor your pneumatic devices over multiple years, you must monitor approximately the same number of devices each year.*~~ *When you monitor the emissions from natural gas pneumatic devices at a well-pad or gathering and boosting site, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad or gathering and boosting site during the same calendar year*<u>*, except devices located outside of a fence-line site*</u>*.*

23. EPA must change the default emission factor for low bleed pneumatic controllers to align with the definition of low bleed pneumatic controllers.

GPA disagrees with the proposed revisions to the default population count emission factor for continuous low bleed pneumatic devices at gathering and boosting facilities.[60] NSPS OOOOa defines a low bleed pneumatic controller as having a bleed rate ≤6 standard cubic feet per hour ("scfh"). The newly revised emission factor of 6.8 scfh[61] directly contradicts the rate for the compliance standard for the exact same piece of equipment, and thus it inherently provides an indication of non-compliance with an already established standard of performance if the device is subject to the NSPS.

GPA also believes the proposed emission factor directly contradicts what EPA considers to be empirical data. An emission factor greater than the 6 scfh standard immediately presumes the device (or some population of devices) is malfunctioning. OEM datasets for continuous low bleed pneumatic controllers often specify bleed rates much lower than 6 scfh, allowing a buffer to account for any periods of malfunction. EPA has proposed to allow use of OEM data for other sources, and GPA recommends expanding this same provision to include low bleed pneumatic controllers. To not allow the use of those same data here would be arbitrary and capricious.

24. EPA should allow reporters to use manufacturer data for device bleed rates.

Similar to above, GPA's recommendation that EPA allow for the use of OEM/manufacturer specification data is not limited to continuous low bleed pneumatic controllers but should be allowable for all natural gas driven pneumatic controllers and pumps. EPA has clearly shown that OEM/manufacturer data is empirical data by allowing it in the revised methane slip calculation methodologies for reciprocating internal combustion engines ("RICE") and natural gas turbines. [62] Allowing OEM specification data for pneumatic controllers and pumps will incentivize the use of better performing devices in the near term while the proposed EG OOOOc requirement for zero-bleed devices is being implemented (if finalized).

[60] *See* 88 Fed. Reg. at 50,438, Table W-1.
[61] *Id.*
[62] *Id.* at 50,356.

25. The midstream industry cannot reasonably meter gas to pneumatic controllers and pumps.

GPA disagrees with the proposed addition of the requirement to use metered supply gas volume data for calculating emissions from pneumatic devices and pumps. This is a very uncommon configuration at midstream facilities, and in most cases would be infeasible to implement. Supply gas sent to pneumatic devices could potentially be originating from several different points at the facility, with each of these supply gas deliveries potentially having different compositions (inlet/field gas, fuel gas, process gas, etc.). Furthermore, it would be even less likely that compositional data for all supply gas streams would be available at every supply gas delivery point. GPA also expects that most of the piping for these supply gas delivery systems would be very small in diameter (< ½" in many cases) and could not feasibly be connected to any metering/analyzer equipment. GPA recommends the proposed requirement to use measured volumetric and composition supply gas data be removed entirely or at most be an optional method.

AGRU Vents and Nitrogen Removal Unit Vents

26. EPA should allow Calculation Methods 2, 3, or 4 to determine CH_4 and CO_2 emissions, and GPA specifically requests that Method 2 not be required if a vent meter is present.

In the current and proposed Subpart W for AGRUs, EPA requires Calculation Method 2 if a vent meter is installed, which mandates quarterly sampling of the acid gas stream. EPA should make this method optional because Calculation Method 2 requires quarterly sampling of sour gas. This is a difficult and potentially dangerous sample to take because of the inherent safety concerns (high H_2S), and therefore many facilities sample this stream quarterly only for the purposes of complying with this rule. In the preamble EPA notes for other sources that:

> Emissions can be reliably calculated for sources such as tanks and glycol dehydrators using standard engineering first principle methods such as those available in API 4697 E&P Tanks and GRI-GLYCalc™. Using such software also addresses safety concerns that are associated with direct emissions measurement from these sources. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions.[63]

EPA should apply the same concern for safety to AGRUs; the sour gas stream being measured has the potential to be lethal.

Further, EPA proposes that glycol dehydrators must use modeling results from other compliance programs. There are state permit-mandated modeling requirements for AGRUs that reporters should be able to use for the GHGRP, but this proposed rule would instead force reporters to depart from those results and regularly collect dangerous samples. Because EPA seeks consistency between the GHGRP and other compliance requirements for glycol dehydrators, it should do the same for AGRUs.

There is a plethora of literature available showing that process simulators agree well with plant data over a wide range of operating conditions, especially for AGRUs. Specifically for methane, the figure below is an excerpt from Mamrosh et al.[64] This shows a parity plot where the experimental value is

[63] *Id*. at 50,289.

[64] D. Mamrosh, et al., "RR-247 Comparison of GPA Midstream Data to Simulation Software Predictions," GPA MIDSTREAM ASSOCIATION RESEARCH REPORT, Project 111 (Feb. 2021).

graphed on the x-axis and the simulation value on the y-axis, such that the parity line is the experimental data, and the simulation predictions are the points shown on the graph. In this source, the error bars shown are those of the experimental data. This research report utilizes an equilibrium constant K-value (a representation of solubility) for convenience in comparing Vapor-Liquid Equilibrium data. This shows that process simulators are typically very accurate at predicting methane content from AGRUs.

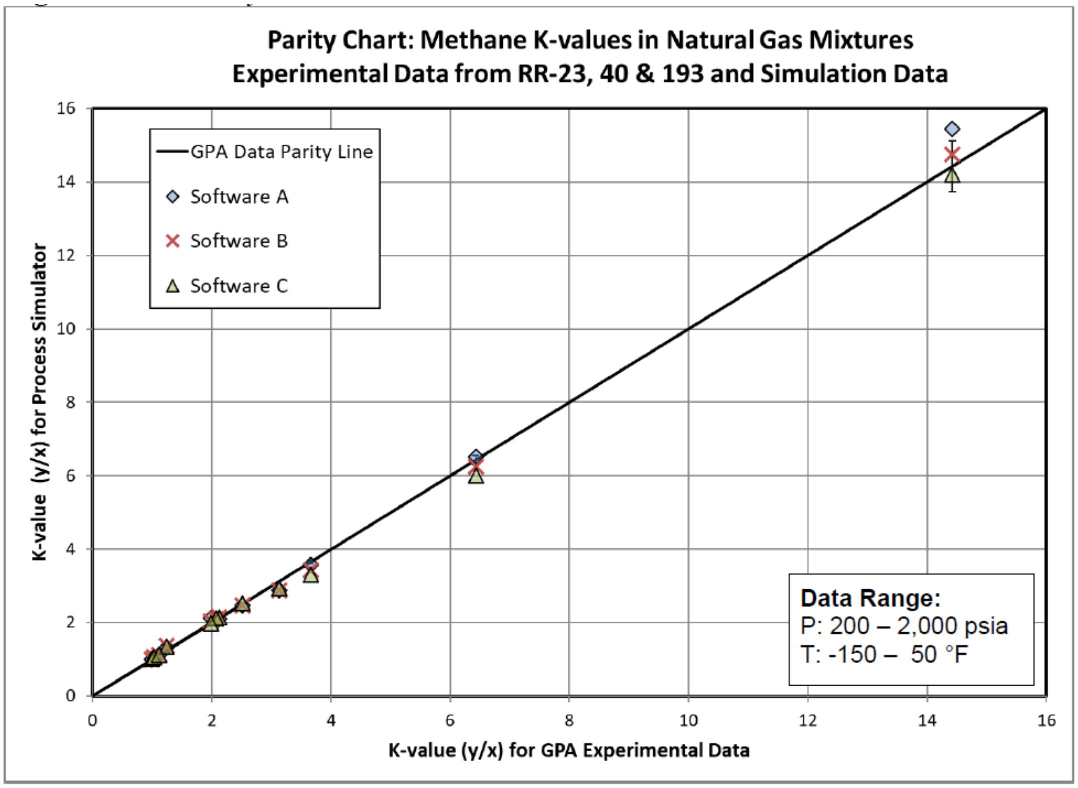

Figure 1: Copied from "Figure 3.1.1 Parity plot for Methane K-values for Data from RR-23, 40, and 193" from Mamrosh et al.

Similarly for CO_2 in AGRUs, the figure below from Pieronek et al.[65] shows very good agreement between data and simulation.

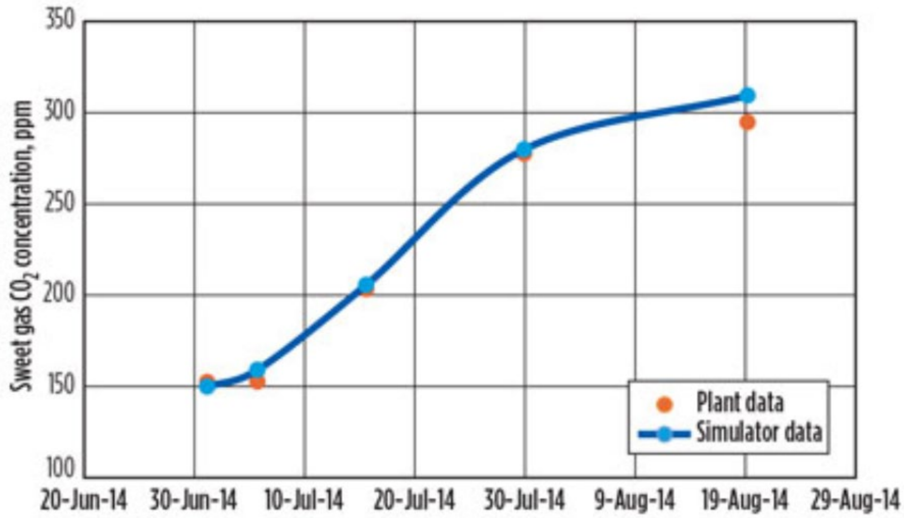

Figure 2: Copied from "Fig. 2. Simulator vs. operating data for sweet gas CO_2 concentration" in Pieronek et al.

[65] M. Pieronek, et al., "Optimize capacity and efficiency for an amine unit," GAS PROCESSING & LNG (Apr. 2015), http://gasprocessingnews.com/articles/2015/04/optimize-capacity-and-efficiency-for-an-amine-unit.

Many other literature sources exist that also show good agreement between process simulation software and operating data.[66,67,68,69,70,71,72,73,74,75,76,77] As such, Method 4 should be allowed for use even if a vent meter is present.

We also have reservations regarding the reliability of utilizing Method 3 (mass balance) for estimating methane emissions from AGRUs. Typically, operators rely on data from facility (or site) inlet and outlet streams, and employing a methane mass balance across the entire site poses two significant challenges:

1) In ideal conditions where flow and composition measurements are perfectly accurate, there is a theoretical risk of double-counting methane losses from other sources such as fugitive emissions or compressors; and

2) In practical terms, the volume of methane vented from AGRUs is generally negligible when compared to the overall methane flow through a facility. Consequently, using this method could potentially yield negative methane emissions values or otherwise inaccurate estimates.

To address these issues, GPA proposes the following revision to the proposed regulatory text:

> *98.233(d)(2) Calculation Method 2. For CO_2 emissions, if a CEMS is not available but a vent meter is installed, ~~use~~ the CO_2 composition and annual volume of vent gas can be*

[66] N.S. Darani, et al., "Simulation and Optimization of the Acid Gas Absorption Process by an Aqueous Diethanolamine Solution in a Natural Gas Sweetening Unit," ACS OMEGA (Apr. 30, 2021), https://pubs.acs.org/doi/10.1021/acsomega.1c00744.

[67] Y. Zheng, et al., "Simulation and pilot plant measurement for CO_2 absorption with mixed amines," ENERGY PROCEDIA 4: 299-06 (2011), *available at* https://www.sciencedirect.com/.

[68] A. Erfani, et al., "Simulation of an operational amine based CO_2 removal plant as an example of CO_2 capture at coal-fired power plants," PETROLEUM AND COAL, https://www.vurup.sk/wp-content/uploads/dlm_uploads/2017/07/pc_1_2015_boroojerdi_323_2.pdf.

[69] D. Mamrosh, et al., "RR-250 Comparison of GPA Midstream Data to Simulation Software Predictions," GPA MIDSTREAM ASSOCIATION RESEARCH REPORT, Project 182 (Feb. 2021).

[70] I.M.S. Larsen, "Simulation and validation of CO_2 mass transfer processes in aqueous MEA solutions with Aspen Plus at CO_2 Technology Centre Mongstad," Master's Thesis, Telemark University College, Norway (2014), https://www.ieaghg.org/docs/General_Docs/PCCC3_PDF/3_PCCC3_4C_Hamborg.pdf.

[71] K.A. Sætre, "Evaluation of process simulation tools at TCM", Master Thesis, University College of Southeast Norway, 2016.

[72] L.E. Øi, et al., "Comparison of Simulation Tools to Fit and Predict Performance Data of CO_2 Absorption into Monoethanol Amine at CO_2 Technology Centre Mongstad (TCM)," PROCEEDINGS OF THE 59TH CONFERENCE ON SIMULATION AND MODELLING (SIMS 59) (Sept. 26-28, 2018), Oslo Metropolitan University, Norway, https://ep.liu.se/ecp/153/032/ecp18153032.pdf.

[73] S. Moioli & L. Pellegrini, "2013 Regeneration section of CO_2 capture plant by MEA scrubbing with a rate-based model," CHEMICAL ENGINEERING TRANSACTIONS (2013), https://www.aidic.it/cet/13/32/309.pdf.

[74] S. S. Warudkar, et al., "Influence of stripper operating parameters on the performance of amine absorption systems for post-combustion carbon capture: Part I. High pressure strippers," INT. J. GREENHOUSE GAS CONTROL (2013), https://porousmedia.rice.edu/resources/Stripper%20High%20Pressure.pdf.

[75] E. Alfadala & E. Al-Musleh, "Simulation of an acid gas removal process using methyldiethanolamine; an equilibrium approach," PROCEEDINGS OF THE 1ST ANNUAL GAS PROCESSING SYMPOSIUM (Jan. 10-12, 2009), https://www.sciencedirect.com/science/article/abs/pii/B978044453292350033X.

[76] X. Luo, et al., "Comparison and validation of simulation codes against sixteen sets of data from four different pilot plants," ENERGY PROCEDIA (Feb. 2009), https://www.sciencedirect.com/science/article/pii/S1876610209001659.

[77] J. Polasek & J. Bullin, "Selecting amines for sweetening units," ENERGY PROGRESS, 146–149 (Sept. 1984), https://www.osti.gov/biblio/5979009.

used to calculate emissions using Equation W-3 of this section. For CH_4 emissions, if a vent meter is installed, including the volumetric flow rate monitor on a CEMS for CO_2, you may use the CH_4 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

27. EPA must clarify that gases sent to acid gas injection wells or geologically sequestered should not be reported as emissions under Subpart W.

AGRU vent streams are sometimes sent to acid gas injection wells or sequestered underground. These sequestered gas streams are not emissions, and reporters should not be required to report them as such (or pay fees on the sequestered gases). EPA has indicated in the past that sequestered gas streams must be reported under Subpart W by noting that:

> EPA disagrees with the modifications suggested by the commenter. In the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009), EPA was clear that subpart methods and calculation procedures must be followed whether or not there is subsequent injection underground or geologic sequestration. The GHG Reporting Program is not an emissions inventory; rather it is a reporting program that collects data to inform future climate change policies.[78]

With the methane fee now relying on the emissions data reported under the GHGRP to impose fees, EPA needs to make conforming changes and recognize that the GHGRP is not simply "collect[ing] data to inform future climate change policies." Moving forward with anything different would be in direct conflict with the intent of the Inflation Reduction Act. As such, any gas streams injected underground or geologically sequestered need to be exempted from the reporting requirements of Subpart W. Acid gas injection is generally considered an effective method of reducing emissions to the atmosphere[79] and should be acknowledged as such in Subpart W instead of potentially penalizing reporters who utilize this technology.

28. For calculation method 4 (process simulation), methane content of outlet natural gas should not be a required simulation input.

For Calculation Method 4, EPA is proposing to add the CH_4 content of the outlet natural gas as a parameter that must be used to characterize emissions [98.233(d)(4)(v)], but this is not analogous to the acid gas content of the outlet natural gas as the proposal erroneously states. The methane content of the outlet natural gas is not an input required for process simulation, and as such should not be considered a required parameter for this method.

~~98.233(d)(4)(v) CH4 content of outlet natural gas.~~

29. Technical corrections

In the AGRU sections of the rule, the term "*acid gas content*" should be replaced with "*CO_2 content.*" The term "acid gas" can also include other acidic components in a gas stream such as H_2S. To ensure a

[78] EPA, Response to Comments Regarding Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments at 1475, Docket ID No. EPA-HQ-OAR-2009-0923-0582-31 (Nov. 30, 2010) ("EPA 2010 Response to Comments Document").

[79] S. Wong, et al., "Economics of Acid Gas Reinjection: An Innovative CO2 Storage Opportunity," Greenhouse Gas Control Technologies – 6th International Conference (Oct. 2002), https://www.sciencedirect.com/science/article/abs/pii/B9780080442761502701.

clear understanding of requirements, EPA should make the language plain and not use undefined terminology.

Dehydrator Vents – Desiccant Dehydrators

30. EPA should eliminate desiccant dehydrators as a source category, as EPA proposed in the June 2022 Proposal.

As EPA previously acknowledged in its June 2022 Subpart W proposal,[80] desiccant dehydrators are a very small source of GHG emissions under the annual GHGRP. Desiccant dehydrators have negligible quantitative impact to the methane waste fee. EPA's decision in this proposal to "resurrect" desiccant dehydrators as an emissions source, and to require the reporting of 18 separate data elements for this source category, is unjustified. [81] EPA claims that the proposed retention of the source category and addition of the 18 new reporting elements is justified because "CAA section 136(h) directs the EPA to ensure that reporting under subpart W reflects total CH_4 emissions, and we are no longer proposing to remove this source." [82] EPA's proposal collects minimal, if any, additional CH_4 emission data versus the current rule and instead collects dissections of data for emissions that EPA already characterized as being very small. Although EPA proposes to expand the source category to include molecular sieve dehydrators (which we also do not think is justified; see Comment 31 below), EPA acknowledged in the 2022 proposal that the small emissions reported under this source category already appear to include emissions from molecular sieve dehydrators.[83] GPA encourages EPA to act on its previous June 2022 proposal to remove desiccant dehydrators from reporting, allowing petroleum and natural gas companies to focus their attention on other more significant sources.

31. If EPA retains desiccant dehydrators as a source category, it should not include molecular sieve dehydrators in that source category.

EPA proposes to add "molecular sieves" to the definition of "Desiccant" in § 98.6 and require reporting on these sources.[84] GPA opposes this for the reasons below.

As BP America, Inc. explained in its prior comment to EPA (Comment Number EPA-HQ-OAR-2009-0923-1305-12), molecular sieves are solid-bed dehydrators that are usually located at natural gas processing plants to remove water from natural gas. In these dehydrator vessels, wet natural gas is passed through a large bed of solid adsorbent media commonly comprised of zeolites (microporous aluminosilicate materials). As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed onto the surface of these particles. Passing through the entire desiccant bed, almost all water is adsorbed onto the desiccant material, leaving the dry natural gas to exit the contactor.

Natural gas processing plants typically have two molecular sieve vessels in parallel so that one vessel can be in service mode, and the other in regeneration mode (in preparation for switching beds). When the adsorbent media in one molecular vessel is water-loaded, it is typically regenerated by passing hot

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[80] 87 Fed. Reg. at 36,920, 36,986 (June 21, 2022) ("Based on the data reported to date, the emissions from these sources are less than 0.1 percent of total reported emissions from dehydrator vents (in RY2020, desiccant dehydrators contributed 760 $mtCO_2e$ of the total 3.35 million $mtCO_2e$ from all dehydrator vent emissions.")).
[81] 88 Fed. Reg. at 50,321.
[82] *Id.*
[83] 87 Fed. Reg. at 36,986 ("In addition, it appears that a significant percentage of the emissions reported to date may be from molecular sieve dehydrators….").
[84] 88 Fed. Reg. at 50,322.

natural gas through the adsorbent media to dry it and prepare it for subsequent use. The hot natural gas is recycled back to the plant inlet; no gas is released to the atmosphere.

GPA further notes that molecular sieve beds have a long life with desiccant media changeouts typically occurring every 5 to 10 years depending upon application. During these changeouts, natural gas in the molecular sieve vessel is typically blown down to flare or other control devices prior to opening the top hatches. This greatly reduces any type of GHG emissions. Any emissions that do result would be reported either under the control device or as a blowdown since these vessels tend to be larger than 50 cubic feet physical volume. If any of these vessels are less than 50 cubic feet physical volume, their small size and infrequent emissions further justifies excluding them from the GHGRP.

Importantly, in its response to BP America's comment cited above, EPA made the following determination: "With regard to the term desiccant dehydrator, EPA intended that only desiccant dehydrators using a hydrophilic salt material are included under subpart W, and thus, molecular sieve dehydration is not included." [85]

GPA fully supports this previous determination by EPA and suggests that it remain in effect since greenhouse gas emissions from molecular sieves continue to be minimal and can be reported under the blowdown emission source category.

32. If EPA retains the desiccant dehydrator source category, the Agency needs to change the reporting elements.

The proposed reporting structure for the desiccant dehydrator source category adds reporting burden in two ways: (1) requiring reporting only on "opened" dehydrators; and (2) aggregating data across the facility or site only on "opened" dehydrators. While the current rule requires reporting on an aggregated basis, it does not have all the data dissections that EPA proposes here, and thus the current aggregation is not difficult. All the data are collected and calculated on a per-equipment basis, and as such, it is much more straightforward to report on a per-equipment basis than as aggregates. For reporters that use databases to handle the massive calculation and reporting burden of Subpart W, it is easier to report per-equipment regardless of whether the vessel was opened or not. If EPA retains this source category (which for the reasons discussed in Comment 31 above, we think it should not), EPA should restructure the reporting section to require only the reporting of a simple list of each desiccant dehydrator, what type it is, whether it was controlled, how many times it was opened (including zero), volume, and emissions.

GPA also notes that the desiccant reporting section makes frequent reference to routing emissions to "regenerator firebox/fire tubes."[86] This appears to be lifted from the glycol dehydrator section and may be a mistake by EPA. We are not aware of desiccant dehydrators (molecular sieve or otherwise) with this configuration. It might be more appropriate to reference non-flare combustion calculations.

Further, EPA should be aware that a molecular sieve dehydrator may have multiple control routing (e.g., vapor recovery followed by flare). Thus, the "counts" of dehydrators by control technique may not align with counts of total desiccant dehydrators.

[85] EPA 2010 Response to Comments Document at 1727.

[86] *See, e.g.*, 88 Fed. Reg. at 50,319-21.

33. Technical corrections

Proposed 98.236(e)(3)(vii)(B) should be changed as follows because 98.236(e)(3) specifies reporting requirements for desiccant dehydrators, not glycol dehydrators:

> *98.236(e)(3)(vii)(B) Total volume of gas ~~from the flash tank~~ to a regenerator firebox/fire tubes, in standard cubic feet.*

Dehydrator Vents – Glycol Dehydrators

34. EPA must clarify reporting requirements for simulation inputs.

For glycol dehydrators that use Calculation Method 1 (process simulation), EPA says, "If paragraph (e)(1)(i) through (xi) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation" [98.233(e)(1)]. GPA supports this proposed language.

In the reporting section, however, EPA instructs reporters to report this data as "annual average." But "annual average" implies a different standard than "measurements reflective of representative operating conditions." GPA assumes EPA's intent is that "annual average" is supposed to capture the case of more than one simulation covering the reporting period, and the data reported here is to be the average of the inputs to each simulation. If this is the case, however, EPA must clarify this interpretation. GPA also notes that the term "annual average" can be confusing if the glycol dehydrator is not operating for a portion of the year.

35. EPA must revise requirements for simulation input parameter measurements.

For large glycol dehydrators, EPA is proposing to require that certain input parameters are based on actual measurements at the unit level to improve the accuracy of the reported emissions for these sources. Some of the items proposed to be based on actual measurements are not reasonable, as described below.

Feed natural gas flow rate: It is common for booster stations to have measurement only on the discharge gas. Measurement of gas coming in is not direct and would be based on wellhead volumes, which are difficult data to maintain and collect because wells come on and off. EPA should clarify this measurement can be based on facility discharge meters or wellhead meters. Otherwise, reporters may be forced by this rule to install inlet gas metering, which would be enormously expensive and would take years to install, likely involving facility shutdowns to do so and provide little additional precision in emission reporting. GPA suggests the following change to the proposed regulatory text:

> *98.233(e)(1)(i) Feed natural gas flow rate (~~must be measured~~ based on measured data).*

Feed natural gas water content: This is not typically measured and is instead calculated by the process simulation based on contactor temperature and pressure with an assumption of saturated gas, which is a technically sound assumption. EPA should remove this measurement requirement. GPA suggests the following change to the proposed regulatory text:

> *98.233(e)(1)(ii) Feed natural gas water content ~~(must be measured)~~.*

Wet natural gas composition: EPA proposes that reporters must use the simulation results used from other compliance programs. However, not all compliance programs require annual composition analysis. As such, EPA needs to clarify whether reporters are compelled to use the simulation(s) from other compliance programs (which may not be utilizing a gas analysis pulled during the reporting year) or if reporters can (or must) run a new simulation with an analysis pulled during the reporting year.

36. Process simulations run for "internal review" should not be mandatory to consider.

In the preamble, EPA proposes that Calculation Method 1 (process simulations) must be used if that method is otherwise used for environmental compliance or reporting purposes, "including but not limited to compliance with Federal or state regulations, air permit requirements, annual inventory reporting, or *internal review.*"[87]

Although GPA understands the intent of this concept (see additional consideration in Comment 37 below), it should be limited to compliance programs only, and not apply to "internal review." Simulations run for purposes other than compliance may not meet the GHGRP's goal of estimating emissions as accurately as possible. In addition to accurately calculating emissions, process simulators are used for a multitude of other reasons internally in industry. These uses can range from exploring possible engineering adjustments or adding additional equipment for various processes that may never be implemented to various other "what-if" scenarios at the facility (for example worst-case safety scenarios for relief valve sizing), which do not apply to annual emissions estimations. Even if the models are representative, it will be extremely difficult to ensure that any process simulation conducted for any "internal" purpose is included in the GHGRP.

Additionally, while the preamble language is clear, the proposed regulatory text language is not. The regulatory text language should be strengthened to convey EPA's intent as expressed in the preamble, as GPA suggests below in Comment 37, and similarly in Comment 51 as applied to atmospheric storage tanks.

37. Clarification is needed in using simulations for compliance and reporting under Subpart W.

As noted in the previous comment, EPA proposes that Calculation Method 1 (process simulations) must be used if that method is otherwise used for environmental compliance or reporting purposes, and further states reporters "must use the results of the model to determine annual mass emissions."

While GPA understands the desire for consistent reporting across programs where possible, this is unclear on multiple fronts and may add unexpected complications. First, "the model" is not defined and could be interpreted as the exact same model with the exact same input parameters as any of the listed regulations, requirements, or reports. Reporting expectations under Subpart W may be different than these other purposes. Especially in terms of "air permit requirements"[88] mentioned in the preamble, it is ambiguous if this requirement would necessitate using input parameters from the initial air permit application, which would almost certainly not accurately reflect the current year's operations. GPA assumes this was not the intent, but the language is vague. If this requirement is included in the final rule, EPA should clarify that the appropriate input parameters specified in 98.233(e)(1)(i) through (xi) should be applied to any models used for reporting with Method 1. GPA suggests replacing "the model" with "this method" for clarity, as shown below.

Additionally, this requirement could unduly restrict reporters to a single software program to perform calculations. If this is intended for application on a per-reporting-year basis, this may not be as burdensome, as it is reasonable that a reporter will likely have access to a particular software for a given

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[87] *Id.* at 50,319 (emphasis added).
[88] *Id*.

reporting year. However, with the current language, this could be interpreted as requiring the same model in the same software over many years. If a reporter acquires a new software program that meets the requirements of 98.233(e)(1), they should be allowed to use it for Method 1 calculations, even if they used a different software program to calculate emissions in the past or for other purposes. Furthermore, requirement might be unworkable in the case of a change in ownership. This is because when assets are sold, simulation files may not be transferred to the owner, or the buyer may not have access to the same software program used by the seller. In such cases, requiring the same software or the same model may be impossible.

GPA requests that EPA reconsider the necessity of this requirement given these complexities and potential confusion around implementation. However, if this provision is included in the final rule, GPA suggests the following regulatory text combining these clarity concerns with those from Comment 36 above:

> *98.233(e) If you are required to or elect to use the method in paragraph (e)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting, you must use the results of ~~the model~~ this method to determine annual mass emissions.*

38. EPA should remove the requirement to calculate "maximum potential annual vented emissions."

Proposed 98.233(e)(4)(i) specifies that:

> *When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate maximum potential annual vented emissions as specified in paragraph (e)(1) or (2) of this section, and calculate an average hourly vented emissions rate by dividing the maximum potential annual vented emissions by the number of hours that the dehydrator was in operation.*[89]

EPA should remove the requirement to calculate the "maximum potential annual vented emissions." First, EPA cannot mandate that reporters use simulations from other compliance programs and then also mandate procedures for how to run the process simulation because this could cause direct conflict in requirements. Second, proposed 98.233(e)(1) indicates simulation inputs should "represent the operating conditions," not represent maximum emissions, which similarly could conflict with compliance programs. Assuming worst-case conditions is required to determine a maximum potential case, which does not reflect actual operations and does not further the EPA's goal of accurately determining emissions. Additionally, because EPA allows for multiple simulations to cover the reporting period, the term "annual" should be removed.

To address these issues, GPA suggests the following changes be made to the proposed regulatory text:

> *98.233(e)(4) When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate ~~maximum potential annual~~ vented emissions as specified in paragraph (e)(1) or (2) of this section, and calculate an average hourly vented emissions rate by dividing the ~~maximum potential annual~~ calculated vented emissions by the number of hours that the dehydrator was in operation.*

[89] *Id.* at 50,389-90.

39. EPA should not require separate reporting of flash tanks and still vent emissions.

EPA is proposing under 98.236(e) to require separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. EPA claims the proposed data elements are included in the output files from the modeling software used for glycol dehydrators, and therefore, this provision is not expected to be difficult for reporters to implement. [90]

EPA is incorrect that this results in minimal additional burden, however, because GLYCalc is still widely used (and is often required to be used by permit), and EPA proposes that reporters are required to use simulation results from other compliance programs. Unfortunately, GLYCalc does not output data in a useful format for automation, so the results have to be manually transferred from GLYCalc to the system or spreadsheet the reporter is using. This requirement therefore adds significant additional reporting burden resulting from the manual transfer of both flash tank vent emissions and still vent emissions.

40. Technical corrections

Proposed 98.233(e)(4) ("*Emissions vented directly to atmosphere from dehydrators routed to a vapor recovery system, flare, or regenerator firebox/fire tubes*") directs the reporter to calculate only those emissions directly vented to the atmosphere.[91] The introduction paragraph 98.233(e), however, implies that uncontrolled emissions are calculated and then adjusted downward to account for control. As a result, GPA suggests that the following correction be made to proposed 98.233(e):

> *98.233(e) …If emissions from dehydrator vents are routed to a vapor recovery system, you must calculate ~~adjust~~ the emissions ~~downward~~ according to paragraph (e)(4) of this section.*

Blowdown Vent Stacks

41. "Best available information" should be allowed for determining the pressure and temperature of any blowdown.

EPA is proposing to allow and clarify use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown.[92] GPA supports this change, but we also request that the language "best available information" be applied to *all* blowdowns—not just emergency blowdowns. Operators do not always have a temperature or pressure gauge at the blowdown source, nor is it reasonable to expect operators to install such gauges. It is also not appropriate to request an "engineering estimate" for a simple matter of determining a reasonable estimate of the gas temperature and pressure. "Best available information" is a broad term that requires

[90] *Id.* at 50,320.

[91] Proposed 40 C.F.R. § 98.233(e)(4) ("*If the dehydrator(s) has a vapor recovery system, routes emissions to a flare, or routes emissions to a regenerator firebox/fire tubes and you use Calculation Method 1 or Calculation Method 2 in paragraph (e)(1) or (2) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes as specified in paragraphs (e)(4)(i) and (ii) of this section. If the dehydrator(s) has a vapor recovery system or routes emissions to a flare and you use Calculation Method 3 in paragraph (e)(3) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (e)(4)(iii) of this section*") (emphases added).

[92] 88 Fed. Reg. at 50,302, 50,325.

operators to use their best data, which is an appropriate standard for this requirement. GPA suggests the following changes to the proposed regulatory text:

98.233(i)(2)(i)

Ta = Temperature at actual conditions in the unique physical volume (°F)~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information may be used to determine the temperature.

Pa = Absolute pressure at actual conditions in the unique physical volume (psia)~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information may be used to determine the pressure.

Ta,p = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on~~ best available information may be used to determine the temperature.

Pa,b,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the beginning of the blowdown~~.

Pa,e,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"~~; 0 if blowdown volume is purged using non-GHG gases. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the end of the blowdown~~. You may assume 0 if blowdown volume is purged using non-GHG gases.

Atmospheric Storage Tanks (including Produced Water Storage Tanks)

42. EPA should not assume an open thief hatch has zero capture efficiency.

EPA proposes that reporters must assume zero percent capture efficiency when thief hatches are found open or not properly seated.[93] EPA has not provided a justification for this assumption in the Preamble or Technical Support Document. If a tank is controlled with a vapor recovery unit ("VRU"), for example, the VRU does not run all the time. It turns on only when there is high enough pressure in the tank. If the vapors in the tank overwhelm the VRU, the tank thief hatch may open. This does not mean, however,

[93] *Id*. at 50,326.

that the VRU is no longer collecting any vapors. Depending on the pressures in the tanks and the pressures in the lines routing emissions to the associated control devices, in some situations, there may be some continued--though reduced--amount of capture. Therefore, GPA proposes that EPA allow engineering estimates of capture efficiencies to be used in situations where there are available data to make those estimates.

43. Reporters must be able to account for cessation of thief hatch emissions.

EPA proposes assuming zero percent capture efficiency if a thief hatch is found open or not properly seated, and if one visual inspection is performed per year, that emissions calculations are performed assuming that the thief hatch was open for the entire calendar year. [94]

For gas-liquid separator dump valve malfunctions, however, EPA has proposed that if a dump valve is fixed following the visual inspection, the time period for which the dump valve was stuck open will end upon repair. To maintain consistency and to increase the accuracy of reported emissions, GPA proposes the inclusion of a similar provision for thief hatches. When an open or not properly seated thief hatch is closed, re-seated, and/or repaired after detection in the annual visual inspection, the reporter should be allowed to document the repair/closure and the time period for which the thief hatch was open or not properly seated should end upon closure/re-seating/repair. This also aligns with the Inflation Reduction Act directive to allow reporters to incorporate empirical data. Mandating the assumption of ongoing emissions even after the emissions are resolved contradicts the IRA's directive to use empirical data and is arbitrary and capricious.

44. An open or not properly seated thief hatch should be defined.

EPA needs to define an open or not properly seated thief hatch, so that it can be consistently applied. GPA proposes the following definition: "*A thief hatch is open or not properly seated if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal.*" If EPA chooses not to define an open or not properly seated thief hatch as provided above, EPA needs to clarify that leaks that can only be identified through use of an OGI camera or similar detection technology do not meet the definition of an open or not properly seated thief hatch. This definition also aligns with the EPA's proposed inspection techniques for thief hatches (98.233(j)(7)).

45. Tank pressure sensors should be allowed to determine if a thief hatch is open.

GPA notes that tank pressure sensors should be acceptable to determine if tank thief hatches are open or not properly seated. On controlled tanks, these sensors will register (for example) between 0.8 and 8 pounds of pressure. A pressure indication outside of this range would indicate an issue with the thief hatch. Pressure indication could in fact be more accurate than a visual inspection in the case of a not properly seated thief hatch. Allowing pressure sensor data will improve the accuracy of reported emissions, incorporate empirical data, and not force operators to assume thief hatch emissions were occurring when monitored data clearly indicates they were not. GPA suggests the following changes to the proposed regulatory text to capture this concept:

> *98.233(j)(7) Thief hatches. If a thief hatch sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open or not properly seated. An applicable operating thief hatch sensor must be capable of transmitting and logging data whenever a thief hatch is open or not properly seated, as well as when the thief*

[94] *Id.*

hatch is subsequently closed. If a tank pressure sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the pressure sensor to determine periods when the thief hatch is open or not properly seated. An applicable operating pressure sensor must be capable of transmitting and logging tank pressure data. If an applicable thief hatch sensor or tank pressure sensor is not present or operating, you must perform a visual inspection of each thief hatch on a controlled atmospheric pressure storage tank in accordance with paragraph (j)(7)(i) through (iii) of this section.

GPA further notes that "thief hatch sensor" is an appropriate term that can accommodate many technologies used to detect thief hatch emissions, including tank vibration/acoustic sensors.

46. Inspection for stuck dump valves must extend beyond visual assessments alone.

EPA proposes mandated visual inspections of gas-liquid separator dump valves on uncontrolled tanks.[95] EPA should allow alternative inspection methods, such as utilizing OGI cameras or advanced technology to detect excessive tank emissions. Another effective approach to identify stuck dump valves involves auditory inspections of the tank, particularly in cases where tanks are designed with submerged fill—a stuck dump valve allowing gas flow into the tank produces noticeable "bubbling" sounds. Relying solely on visual inspections of the dump valves themselves may not always reveal underlying issues. Broadening the spectrum of inspection options empowers reporters to encompass all relevant empirical data accurately. Accordingly, GPA proposes the following changes to the regulatory text:

98.233(j)(5)(i) You must perform an ~~visual~~ inspection ~~of each gas-liquid separator liquid dump valve~~ to determine if the gas-liquid separator dump valve is stuck in an open or partially open position, in accordance with paragraph (j)(5)(i)(A) and (B) of this section.

98.233(j)(5)(i)(A) ~~Visual inspections~~ Inspections must be conducted at least once in a calendar year.

47. Emission calculations for produced water tanks should be limited to emissions associated with stuck dump valves.

EPA proposes the inclusion of flashing emissions from produced water tanks,[96] in addition to the existing requirement to report flashing emissions from hydrocarbon tanks. Produced water tanks (i.e., tanks that receive a produced water stream with no measurable hydrocarbons present) are not expected to have significant emissions during times of normal operation. Substantive emissions are the result of improperly operating tanks, and these emissions are addressed otherwise in the GHGRP via stuck dump valve requirements. GPA proposes limiting the required emission calculations to emissions associated with stuck dump valves. This is how emissions from hydrocarbon tanks in the transmission and (as proposed) underground storage segments are determined.

If EPA maintains requirements to report produced water tank flashing emissions, GPA supports the allowance of multiple calculation methods to determine these emissions.

[95] *Id.* at 50,327.
[96] *Id.* at 50,304.

48. **Calculation requirements must be adjusted to account for mixtures of produced water and hydrocarbon liquids.**

Many facilities produce both hydrocarbon liquids (condensate) and produced water. A mixture of these products will typically be separated from the gas and will flow into the associated tank battery. While some separation of water and hydrocarbon liquids occurs in the separator, many tanks contain a mixture of condensate and produced water. As such, Calculation Methods 1 and 3 must be adjusted.

In the cases where tanks/separators receive both condensate and produced water, when modeling is performed for Method 1, the calculation of flashing emissions generally provides the total amount of flash gas that is emitted from both products based on gas and/or liquid composition and throughputs. Therefore, when using Method 1, it is not generally feasible to calculate produced water and condensate flashing separately, because the two products are typically mixed when flashing occurs. GPA proposes that in cases where tanks receive a mixture of condensate and produced water that flashing emissions be reported as a whole for both products, as that is representative of the mechanism of the actual emissions source and the results that are provided by modeling.

For Calculation Method 3, the proposed rule is unclear on which equation (produced water or hydrocarbon) should be used for tanks that receive a mixture of the two products. GPA requests clarification on how to account for this common scenario, and we propose the following: in cases where a liquid stream contains any measurable hydrocarbons, W15-A should be used. If a stream contains no measurable hydrocarbons, W15-B should be used.

49. **GPA requests clarification on measurement frequency expectations.**

EPA is proposing to require the use of measured input parameters to model tank emissions calculated using Method 1, including measurement of separator temperature and pressure, hydrocarbon liquid production rate, API gravity, Reid Vapor Pressure, and composition. EPA states that these parameters must be obtained by measurement "reflective of representative operating conditions over the time period covered by the simulation." [97] GPA requests clarification on whether EPA intends for these parameters to be measured annually. If that is EPA's intention, GPA requests a five-year measurement time frame in which measurements are gathered every five years due to the high level of burden that the measurement and sampling requirements impose, particularly in light of the relatively small amount of emissions that atmospheric pressure storage tanks represent as a source category.

Many of these parameters for tanks are not regularly directly measured and sharply increasing the number of tanks and separators requiring this level of measurement will result in a significant increase in data management burden and cost because reporters must pull regular samples and send to them to laboratories for analysis. It can also be difficult to obtain liquid samples because the liquids must be collected prior to flashing, so this usually involves collecting liquids at the separator. There are not always liquids present in the separator to sample, especially if the separator has recently dumped to the tank. It is also unclear whether the third-party laboratories that many reporters use will be able to accommodate the increase in sampling. Additionally, in some cases, reporters may need to purchase and install appropriate sampling ports and measurement devices in order capture this information, further increasing the costs associated with gathering data for an emissions source that represents only a small fraction of the reporter's overall greenhouse gas emissions.

Additionally, EPA should limit the requirement to measure API gravity and Reid Vapor Pressure as parameters for Calculation Method 1. Not all process simulation software requires these two

[97] *Id.* at 50,329.

parameters to run the model. In at least some robust process simulators (e.g., BR&E ProMax, AspenTech HYSYS), if a hydrocarbon liquids composition is provided for the tank feed (as is currently required), API gravity and Reid Vapor Pressure are not needed as inputs to the simulation as these can be calculated from the other input parameters. As a result, GPA suggests the following revisions to the proposed regulatory text:

> *98.233(j)(1)(iii) For atmospheric pressure storage tanks receiving hydrocarbon liquids, sales oil or stabilized hydrocarbon liquids API gravity (must be measured if required by the model).*

> *98.233(j)(1)(vii) Well, separator, or non-separator equipment hydrocarbon liquids or produced water composition and Reid vapor pressure (must be measured if required by the model).*

50. The proposed names for the tank source categories are confusing.

EPA proposes to rename the "transmission storage tank" source category to "condensate storage tanks" and then apply this term only to transmission and underground storage facilities.[98] Unfortunately, this nomenclature is confusing and lacks transparency because many gathering and boosting, and gas processing facilities also have tanks that collect condensate that are commonly referred to as "condensate tanks." To address this issue, GPA recommends renaming these emission sources "Transmission and underground storage tanks" and "Onshore production, onshore natural gas processing, and onshore petroleum and natural gas gathering and boosting storage tanks." Another possible solution is to combine the two sections on tanks into one.

51. EPA should not require inclusion of models run for "internal review", and reconsider or clarify requirements to use simulations for compliance and reporting.

Very similar language exists in both the *dehydrator vents* section [98.233(e)] and the *hydrocarbon liquids and produced water storage tanks* section [98.233(j)]. GPA has the same concerns for this section as those detailed in Comments 36 and 37.

Process simulations run for "internal review" should not be mandatory consider (see Comment 36), and GPA requests that EPA reconsider the necessity of the requirement to use the same simulations for compliance and reporting given the additional complexities and potential confusion around implementation (see Comment 37). However, if this provision is included in the final rule, GPA suggests the following regulatory text:

> *98.233(j) If you are required to or elect to use the method in paragraph (j)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting for the current reporting year, you must use the results of ~~the model~~ this method to determine annual CH_4 and, if applicable, CO_2 emissions.*

52. EPA should remove the requirement to "Calculate maximum potential vented emissions."

Similar language also exists between the *dehydrator vents* section [98.233(e)] and the Hydrocarbon liquids and produced water storage tanks section [98.233(j)] concerning "maximum potential vented emissions." GPA has the same concerns in this section as those detailed in Comment 38.

[98] *Id.* at 50,301-02.

As mentioned previously, assuming worst-case conditions would be required to determine a maximum potential case, which does not reflect actual operations. This does not further the EPA's goal of accurately determining emissions.

To address these issues, GPA suggests the following changes be made to the proposed regulatory text:

> *98.233(j)(4)(i)(A) Calculate ~~maximum potential~~ vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, and calculate an average hourly vented emissions rate by dividing the ~~maximum potential~~ calculated vented emissions by the number of hours that the tank was in operation.*

Flare Stack Emissions

53. EPA cannot establish flare compliance requirements in Subpart W, and the requirements for flare stack reporting must be simplified.

As discussed above in Comment 6, the GHGRP is an informational program. As EPA noted when it promulgated the program, "[t]he rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions."[99] The revisions to Subpart W cannot be the driver on control of air pollutant emissions. Rather, other provisions of the CAA such as section 111 and 112, are available for this purpose.

Unfortunately, in the proposal, EPA indirectly imposes flare monitoring requirements that go vastly above-and-beyond current requirements for petroleum and natural gas systems operators. This is wholly inappropriate for a reporting rule. If EPA believes current regulations should require additional monitoring for flares in the oil and gas source category, then it should address this directly by revising the specific regulations for emission controls and not indirectly through an emissions inventory reporting rulemaking.

Moreover, it is inappropriate to revise destruction efficiencies in the proposed rule based on a single recent study, Plant et al., and discount all other previous flare studies conducted, many of them specifically to determine destruction efficiencies. EPA cannot set destruction efficiencies for an entire industry based on a single study using only remote sensing technology measurements.

Remote monitoring has a large degree of uncertainty in estimated actual emissions. Without site-level verification of the emission rates, it cannot be the sole determination of emission rates and destruction efficiency. Many companies have begun conducting evaluations of measurements from remote sensing technology versus site level measurements as remote sensing technology increases in use. While the information from the Plant et al. study can be useful from an overall emissions profile perspective, it cannot be the only data used to accurately calculate emissions from a single source since other nearby emitting sources can influence the site-level emission measurements.[100]

Although this study found that "[t]he majority of flares function close to expected performance, with DRE values near 98%,"[101] EPA is only allowing a source to take this level of emission reduction if a flare has additional, expensive monitoring that is not otherwise required by regulations applicable to the

[99] 74 Fed. Reg. at 56,260.

[100] The American Petroleum Institute is submitting comments on additional technical issues involving the Plant et al. study, and GPA urges EPA to pay extra attention to those comments.

[101] Flaring and Fossil Fuels: Uncovering Emissions and Losses (F3UEL) Project, Graham Sustainability Institute, University of Michigan, "Fugitive Emissions from Flaring" (summarizing Plant et al.), https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.

associated industry. Plant et al. does not evaluate individual flare sources to determine if they were even operating within their designed operating range. Therefore, GPA does not believe it is appropriate to develop industry-wide destruction efficiencies based on this study. Notably, Plant et al. states the following:

> Investigations into possible drivers of reduced DRE, such as wind speed (measured at the aircraft), flare volume and temperature (VIIRS), and estimated well age and gas/oil ratio (37) did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets cannot explain most of the observed flare CH_4 DRE variability. Improving attribution to flare design, operation, and environmental conditions would require a different study strategy, likely with more information on individual flare infrastructure and operation.[102]

The Plant et al. study also only observed open flares. EPA must also allow additional methodologies for other types of combustion control devices reported under the flare source category. Enclosed flares and vapor combustors are also reported under the flare source category but operate with different design parameters than a standard flare that must be taken into account when accounting for destruction efficiency and monitoring. Separate DREs must be considered for these devices, and Subpart W should defer to the permit or state requirement, OEM data, and/or performance tests for the DRE for these devices.

54. EPA must revise destruction efficiency tiers to be relevant to the natural gas industry.

EPA seems to have discarded, without explanation, multiple existing flare studies that have been integral to establishing destruction efficiency levels regularly utilized in criteria pollutant annual emissions inventories, best available control technology demonstrations for new source review ("NSR") permits, and compliance. This is arbitrary and capricious. EPA cannot overturn decades worth of precedent based on a single study—especially one that admits it "did not yield compelling explanatory relationships."[103]

Reporters should be allowed to rely on empirical data to overrule the proposed destruction efficiency tiers. For example, if a reporter has a manufacturer guarantee or test data that show a destruction efficiency above the presumed efficiency tiers, that higher level should be allowed to be used.

The proposed approach here forces inconsistent data reporting between Subpart W and other EPA programs such as emissions inventory reporting, excess emissions reports, and permit compliance. For example, midstream operations (encompassing both processing and gathering and boosting stations) typically operate process flares at their sites. Process flares are often required to meet NSPS and NSR permitting requirements, which typically include a requirement to comply with 40 C.F.R. § 60.18, either directly under a NSPS or indirectly through NSR permit conditions. EPA should not dismiss the design or

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[102] Plant, et. al., "Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane," Science (Sept. 29, 2022) (internal citations omitted), https://www.science.org/doi/10.1126/science.abq0385#:~:text=We%20find%20that%20both%20unlit,%25%20confidence%20interval)%20of%20methane.

[103] *See, e.g.*, *Butte County v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) (noting "an agency cannot ignore evidence contradicting its position and 'must take into account whatever in the record fairly detracts from its weight'") (quoting *Universal Camera Corp. v. NLRB*, 340 U.S. 474, 487-88 (1951)).

testing to demonstrate a minimum 98 percent DRE for flares operating according to the requirements of this regulation.

55. EPA seems to confuse "combustion efficiency" with "destruction efficiency."

Throughout the preamble and the proposed regulatory text, EPA consistently used the term "combustion efficiency." However, EPA seems to confuse this term with "destruction efficiency." Combustion efficiency refers to complete combustion (i.e., the fraction of the hydrocarbon stream that is completely oxidized to CO_2) whereas destruction efficiency is the fraction of the hydrocarbon stream that is destroyed in the flare and includes the incomplete combustion to other compounds (such as CO). Emission calculations in Subpart W for methane emitted from a flare must be based on *destruction efficiency*, not combustion efficiency, to account for all methane oxidized whether to CO_2 or CO. It is also imperative for EPA to understand the distinction between these terms when evaluating studies and literature on the topic.

56. Best available data must be reinstated as a minimum option for flare flow and composition.

The reporting outlined for flares in the proposed rule is too prescriptive and attempts to impose compliance requirements for operators. The minimum level of monitoring for these sources goes well beyond current requirements for these sources under CAA permits and other EPA or state regulations. Where monitoring is not required by regulation or permit, engineering calculations should continue to be allowed to estimate emissions. EPA must reinstate the proposed removal of best available data calculation methods for flow rate and composition. The flares in midstream operations control streams that are generally consistent in composition.

Midstream operators, similar to upstream operators, have many dispersed sites of operation. Many (if not most) of these operators use a combustion control device at the site to control VOC and/or methane emissions. The level of monitoring proposed under Subpart W, however, for these control devices requires continuous monitoring of flow rate, as well as at least periodic sampling for composition. It is not feasible or economically reasonable to require this level of instrumentation and monitoring to determine flare emissions. Process simulators (combined with monitored operating conditions) and engineering estimates can reasonably estimate flowrates to control devices without costly instrumentation needing to be added to thousands of control devices, particularly control devices that are controlling glycol dehydrators and tanks. These same flowrates are produced from software simulation models that are approved methods for calculating emissions throughout this rule. There is no reason they shouldn't also be included here. This option should also be reflected in reporting requirements in 98.236(n).

57. EPA should not specify monitoring technology to allow flexibility for new technology development.

EPA should incorporate direct or parametric monitoring data into calculations only when the data are available. EPA should also eliminate references to specific types of equipment. This approach ensures flexibility for emerging technology and accommodates changes in regulatory language in other rules without necessitating revisions to Subpart W.

As stated in our comments regarding the proposed NSPS OOOOb and EG OOOOc on storage tank control devices,[104] requiring flow meter measurement is not feasible in many cases because flow measurement

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[104] GPA Comments on NSPS OOOOb and EG OOOOc at 41-42 (Comment VI.B.2).

cannot meet the accuracy requirements in intermittent and low flow scenarios. The proposed rule, however, would require that flow meters be accurate up to 2% at maximum flow rates.[105] In most cases, such accuracy could be achieved only with an optical meter or an ultrasonic flow meter. These typically cost about $30,000 for basic models; however, there is no evidence in the record that justifies compelling the use of these precise and expensive flow meters over less costly flow meters. As with many other types of flow meters, these also struggle with accuracy at lower flow rates such as when the device is only controlling breathing losses from tanks or pressure safety valve discharges at gas plants. As a result of these operating issues, even the most accurate flow meters will lose some accuracy. Accuracy at lower rates can increase with additional flow meter monitoring devices installed in tandem with the basic ultrasonic meter; however, this significantly increases the overall cost of this monitoring equipment. GPA would like to ensure that meters with an accuracy of up to 10 percent at maximum flows, such as thermal dispersion flow monitoring devices, can be used to calculate emissions under this proposed reporting rule, but EPA should not require monitoring and must allow alternative methods of estimating emissions that have significantly lower costs with similar accuracy of emissions. EPA should allow flexibility for flame presence monitoring.

GPA supports the concept of reporters incorporating their best available data in all parts of the rule, including flare flame presence monitoring. GPA does not support, however, GHGRP requirements to monitor for flame presence (see Comment 6). If this requirement is retained, EPA should allow flexibility for this monitoring. Remote visual observation of flares through a video camera should be allowed as an alternative method of verifying flame presence. Operators can view multiple stacks remotely in a control room. Visual observation provides adequate determination of flame presence. EPA should not require that on-site observations are the only opportunity for visual inspection. Newer technology must be allowed under these rules. Allowing remote visual observation not only more efficiently utilizes manpower but can also result in more timely discovery of unlit or malfunctioning flares and implement corrective actions.

Additionally, auto-ignition systems should be allowed to verify flame presence. Texas allows auto-ignition systems where flow to the flare is intermittent,[106] and EPA should do the same here. This eliminates the need for a continuous pilot and reduces the amount of pilot and sweep gas necessary to operate the flare.

58. EPA should not mandate quarterly collection of flare gas composition data for all flares.

Flares operated by midstream operators control streams with a consistent composition that falls well above the minimum requirements in 40 C.F.R. § 60.18 in most cases. Therefore, EPA should allow operators to use best available data to calculate emissions. It is not cost effective to conduct continuous or even quarterly monitoring for composition on these thousands of control devices when the gas routed to the flare is consistent. Operators should be able to use process simulations to calculate the vent gas stream composition to these flares or provide other available data that represent the gas composition. Like flowrates, the composition of gas going to flare is the same composition that comes from the various facilities, which are accurately calculated using simulation software. By extension, site-

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[105] Proposed 40 C.F.R. § 98.234(b) ("You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section."); *id.* § 98.3(i)(3)(i) ("For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale.").

[106] Texas Comm'n on Envtl. Quality, Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, https://www.tceq.texas.gov/permitting/air/newsourcereview/chemical/oil_and_gas_sp.html.

specific HHV can also be provided using a process simulator. This option should be reflected in the reporting requirements of 98.236(n). Additionally, on sour gas streams, collecting regular gas samples increases the safety risk associated with collecting a sample because of high H_2S concentrations, and this safety risk does not result in any significant benefit to determining emission rates. There are other ways that operators can calculate emissions from these streams with reasonable accuracy. Prescriptive requirements for calculations restrict getting the best estimate of emission rates. Therefore, EPA must reinstate the language for estimating emissions from flares.

59. EPA should allow data from advanced technologies.

EPA is highly prescriptive in the current and proposed emissions calculation methodologies, which does not readily accommodate new technology. New technologies continue to be developed, and EPA should develop a process that allows proven technology to be used to determine emissions. Vendors should have an approval process through EPA, and once the technology is approved, it should be available for use in determining emissions under the GHGRP.

For example, GPA is aware of existing technology that remotely monitors and controls the combustion efficiency of a flare. EPA should provide an option for calculating the destruction efficiency of a flare that uses this type of monitoring technology. Existing and future technologies should be allowed to use the actual or calculated destruction efficiency from these advanced monitoring technologies for calculating emissions from flare stacks once the technology has been vetted through a regulatory agency. This will result in a co-benefit of more accurate reporting of emissions and decreased emissions with higher actual destruction efficiencies.

60. Refinery NESHAP Standards exceed necessary requirements for petroleum and natural gas sources.

Sources in the gathering and boosting and processing segments are not subject to the requirements in 40 C.F.R. Part 63, Subpart CC (NESHAP for Petroleum Refineries). Imposing monitoring for GHG emission reporting based on a regulation for refinery flares that midstream operators are not subject to is inappropriate and exceeds EPA's authority under the GHGRP, which, as EPA has stated, "does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions."[107] As stated in Comment 6, EPA cannot require emissions reduction or control through the GHGRP. Gas streams directed to a refinery flare differ significantly from the gas streams routed to midstream flares, making the application of these regulatory requirements inappropriate and warranting their removal from the final rules because they are arbitrary and capricious.

61. EPA should allow at least 98 percent DRE for flares operating within 40 C.F.R. § 60.18 operating parameters.

The 95 percent emission reduction required under NSPS OOOOa (and proposed to be required under NSPS OOOOb and EG OOOOc) should not be a basis for determining flare destruction efficiency. The lower reduction in those regulations was designed to allow operators to use other control options beyond flare combustion devices. Instead, GPA believes a better option is that flares designed according to 40 C.F.R. § 60.18 and operated within design parameters should be given a default 98 percent destruction efficiency. This is consistent with NSR permit authorizations and annual emission inventory calculations for VOC emissions. There are numerous studies that show most flares generally achieve at least 98% DRE when operating within the parameters of 60.18. For flares that are not subject to 40

[107] 74 Fed. Reg. at 56,260.

C.F.R. § 60.18, EPA should allow a minimum 98 percent DRE for flares operated within NSR permit compliance requirements.

Several states allow higher destruction efficiencies if the control device meets certain criteria. For example, North Dakota's High Efficiency Program allows manufacturers to submit testing data on the performance of their control devices within an operating range to establish higher destruction efficiencies.[108] The testing must be reviewed by the state agency, but once approved, an operator can submit a request to use the higher DRE (above 98 percent) for installation of an approved model at a site. EPA should allow these demonstrated higher destruction efficiencies in inventory calculations under the GHGRP.

Other control devices reported under the flare stack source type must be allowed. Pressure-assisted (sometimes called sonic velocity) flares do not meet the flare tip velocity limitations in 40 C.F.R. § 60.18 but have been demonstrated to meet high destruction efficiencies in testing such as for Alternative Means of Emission Limitation. Vapor combustors, enclosed flares, and some thermal oxidizers are also utilized by midstream operators to control emissions. As noted in Comment 53, separate DREs must be considered for these devices, and Subpart W should defer to the permit or state requirement, OEM data, and/or performance tests for the DRE for these devices.

62. GPA supports a zero DRE for instances when a flare is found to be unlit.

GPA agrees that unlit flares should be given a destruction efficiency of zero. Monitoring for flame presence is already a generally accepted practice for combustion control devices and would be an appropriate monitoring data record to require for reporting under this regulation, given that EPA accepts the additional monitoring options addressed in our other comments. This makes logical sense, but as such, it would be inappropriate for EPA to assume a default flare efficiency of 92 percent because it includes data collected from unlit flares (and therefore unlit flare emissions would be "double-counted.")

63. GPA does not support reporting estimated "disaggregated" data for flares.

GPA strongly supports EPA's proposal to consolidate calculation and reporting of flared emissions in the "flare stack" emission source category (and not at individual sources that are controlled by a flare). This alleviates burden and will result in the best emission estimates.

However, EPA proposes two "disaggregation" reporting requirements that GPA does not support: (1) an estimated fraction of total volume flared that was received from another facility solely for flaring [98.236(n)(10)] and (2) estimated disaggregated CH_4, CO_2, and N_2O emissions attributed to each source ((i.e., AGRU vents, dehydrator vents, etc.) [98.236(n)(19)]. GPA firmly pushes back on these proposed requirements. As EPA acknowledges, without massive effort, reporters can only provide "estimates," but it is not appropriate for EPA to ask reporters to certify gross estimates under penalty of law. Additionally, it is not appropriate for EPA to collect estimates and then use these data for any purpose. This is not empirical data as mandated by the Inflation Reduction Act and therefore has no place in this proposal. Additionally, flaring is often caused by a pressure imbalance along the value chain; where that pressure is relieved (flared) may be determined by a variety of factors, but this flared gas is not easily classified as "received from another facility." This can be something of a chicken-and-egg question.

[108] *See* North Dakota Department of Environmental Quality, High Efficiency Program, https://deq.nd.gov/AQ/oilgas/HighEffProgram.aspx.

As noted throughout these comments on flares, EPA is simply overreaching its authority, and EPA needs to pursue flare information and controls by other means. EPA proposes that the following parts of the proposed regulatory text be omitted from the final rule:

> *98.236(n)(10)* ~~*For the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and onshore natural gas processing industry segments, estimated fraction of total volume flared that was received from another facility solely for flaring (e.g., gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).*~~
>
> *98.236(n)(19)* ~~*Estimated disaggregated CH4, CO2, and N2O emissions attributed to each source type as determined using engineering calculations and best available data as specified in § 98.233(n)(10) (i.e., AGR vents, dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, hydrocarbon liquids and produced water storage tanks, well testing venting and flaring, associated gas venting and flaring, other flared sources)*~~*.*

Compressors

64. EPA should not require NOD mode measurements for the gathering and boosting segment, and the Agency should instead develop an emission factor (and also allow companies to use their own emission factors developed for other industry segments).

EPA proposes to remove mandatory periodic NOD mode measurements for compressors located at gas plants and transmission compressor stations. For compressors at onshore petroleum and natural gas production facilities or an onshore petroleum and natural gas gathering and boosting facilities that will be subject to the compressor standards in NSPS OOOOb or EG OOOOc, however, EPA proposes that at least one-third of the subject compressors must be measured during any three consecutive calendar year period for compressors in those industry segments [98.233(o)(10)(i)(B), 98.233(p)(10)(i)(B)].

In our comments on the 2022 proposed rule and in a previous communication with EPA, GPA thanked EPA and noted its support for removing the mandatory NOD mode measurements for compressors at gas plants. [109] GPA now requests that EPA allow, but not require, NOD mode measurements for compressors in the gathering and boosting segment.

Requiring NOD mode measurements at gathering and boosting sites would be even more difficult to implement than at gas plants. EPA states, that "[b]ased on an analysis of all reciprocating and centrifugal compressor measurements for the other industry segments since 2015, approximately one-third of all compressor measurements were performed in [NOD] mode." [110] This occurs purely because the GHGRP currently requires reporters to measure NOD mode once every 3 years; this is not happening because one-third of compressors are in NOD mode at any given time. Gathering and boosting facilities typically have a lower number of compressors (sometimes only 1 or 2 per site), and they are generally running. Compressors are expensive to purchase and operate, and we avoid having compressors running unloaded or sitting idle. As such, compressors are not commonly in NOD mode and collecting this

[109] GPA Comments on 2022 Proposed Rule at 21.
[110] 88 Fed. Reg. at 50,341.

measurement would almost certainly necessitate an otherwise unforced compressor shutdown and blowdown, which could result in the entire site being shut down and potentially upstream emissions if the gas has nowhere else to go.[111] Unneeded shutdowns will increase emissions, increase the reporter's methane fee burden, and likely cause supply disruptions.

Administratively, keeping track of the percent of compressors measured in the NOD mode over three consecutive calendar year periods and then deciding which compressors will be shut down to satisfy the requirement is unreasonable and adds complexity to compliance and recordkeeping. EPA also fails to indicate a statistical significance to the proposed measurement frequency. It is also unclear if reporters are to count the unique compressors measured in NOD mode or unique compressor-year measurements (e.g., if the same compressor was measured in NOD mode in both 2025 and 2026, it is unclear whether that is considered one measured compressor or two).

Another uncertainty surrounds what EPA means by gathering and boosting compressors that "are subject to the reciprocating compressor standards in 40 C.F.R. § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter." [112] What does it mean to be subject to the reciprocating compressor standards? For example, what happens if an approved state plan under EG OOOOc says existing equipment must begin annual measurements within 36 months? Are those compressors subject to the approved state plan when the plan is approved, or when the first measurement is conducted? Or is it some other time?

To alleviate these significant complexities, EPA should use the abundant data provided by GHGRP reporters over many years on NOD mode emissions to develop emission factors. EPA could also allow reporters to use their own emission factors calculated from different industry segments, particularly natural gas processing. This surely aligns with the Inflation Reduction Act's directive to use empirical data. The compressor/engine types and sizes found at natural gas processing facilities are similar to the ones found at gathering and boosting facilities, so isolation valve emission factors could be transferred across these industry segments. Because these compressors do not commonly operate in the NOD mode, emission factors should sufficiently represent emissions.

65. Reporter emission factor requirements need to accommodate additional scenarios.

EPA is proposing to remove the requirement to measure in the NOD mode every three years, and EPA is proposing to add new mode-source combinations. Because of these changes, it is possible that mode-source combination measurements may occasionally not exist, especially if a reporter calculates emission factors at the facility level. EPA should include provisions to allow a reporter to either use the last valid reporter emission factor or (if facility emission factors are otherwise used) allow use of a company-wide emission factor. GPA suggests the following changes to the proposed regulatory text to accomplish this:

> *98.233(o)(6)(iii) …*
>
> *Eq. W-23*
>
> *EFs,m = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter*

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[111] Although compressors sometimes shut down, aligning these shutdowns with NOD mode monitoring (which is often performed by a contractor) is difficult to coordinate, based on the experiences of GPA members collecting NOD measurements as gas plants.
[112] 88 Fed. Reg. at 50,403.

emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.

98.233(p)(6)(iii) …

Eq. W-28

EFs,m = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years. If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.

Equipment Leak Surveys and Equipment Leaks by Population Count

66. EPA should not require use of the proposed undetected leak factor for equipment leak emission estimates.

GPA recognizes EPA's intent to ensure all equipment leak emissions are accounted for, but use of an undetected leak adjustment factor, k, based on the Pacsi et al. (2019) study data does not meet the criteria of empirical data. That study included surveys of 67 sites, but leaks were only detected at 52 sites, so the data gathered pertains only to these 52 sites. Moreover, of those 67 sites, 10 sites were identified as "boosting and gathering" with the remaining sites falling into the categories of well sites/well production/central production. For the 10 "boosting and gathering" sites, only 5 had leaks identified as part of the study. Observed leak data from just 5 sites in the gathering and boosting sector does not accurately represent the entirety of this sector, nor does this level of data qualify as a statistically significant data set of empirical data to justify the creation of an undetected leak factor to be applied to all surveyed gathering and boosting sector facilities.

The Pacsi et al. (2019) study compared the monitoring methods of OGI and flame ionization detector. These two monitoring methods have extremely different procedures and techniques while being used with federal or state leak detection and repair ("LDAR") compliance. GPA believes if EPA implies that leaks are inadvertently being "undetected," this may have unintended consequences for the oil and gas industry. GPA agrees that current GHGRP component emission factors may require an improved quantification value structured around practices and improvements to equipment within the industry segments subject to GHGRP, but just assuming components are going undetected during weekly, monthly, quarterly, semi-annual, and annual inspections via audio, visual, and olfactory inspections, OGI, and Method 21 is an inappropriate approach. EPA implies in the proposed rule that industry segments subject to the GHGRP are not making every available effort to comply with regulatory LDAR standards in current federal and state policies. This is simply untrue.

GPA proposes that EPA remove undetected leak adjustment factor, k, in equation W-30. It would be more beneficial if EPA would use the result from any as-found leak detection method without implied adjustments to the count of components found. Indeed, the Pacsi et al. (2019) study expressly specifies that "this study was not designed to understand the differences in emission detection technology deployment but may explain differences in emission estimates from this study compared to current US emission factors."

The current and proposed Subpart W rules allow for the use of various handheld devices for leak detection (OGI, Method 21, etc.). Any detected leaks, coupled with leaker emission factors developed from published empirical data, then comprise the total observed emission leaks at each site. The addition of an undetected leak factor assumes that the observed leak data collected from the leak surveys is unreliable--even though the associated survey is performed based on EPA monitoring and training criteria (98.234(a) and the requirements referenced therein such as OOOOb). This assumption is arbitrary and capricious. GPA supports EPA's existing monitoring and training criteria related to the use of the above noted leak detection technologies but does not support the implication in the proposed rule that these technologies and EPA's regulatory guidance result in insufficient leak detection.

67. EPA should not finalize the proposed whole gas emission factors for OGI.

GPA proposes that EPA retain the current alignment between the whole gas leaker emission factors for Method 21 at a 10,000 parts per million ("ppm") leak definition and OGI.[113] In the final NSPS OOOOa rule, EPA specified in response to a comment within the published version of NSPS 40 C.F.R. Part 60, Subpart OOOOa that:

> Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired.[114]

It is improper for EPA to create a whole gas leaker emission factor for the proposed 98.234(a)(1) (OGI) that is almost double the proposed value of 98.234(a)(7) (Method 21 at a 10,000 ppm leak definition). It would not be empirical data specifying an emission factor of this magnitude simply because of the leak detection instrument, especially when according to EPA in NSPS OOOOa, OGI achieves the same level of emission detection as using the Method 21 instrument when it is calibrated to detect emissions at a threshold of 10,000 ppm or greater.

In addition, EPA's analysis for the proposed NSPS OOOOb identified OGI as both cost-effective and as the BSER for well sites and compressor stations, providing a viable alternative to Method 21. Further, as corroborated by the studies referenced in this proposal, namely Pacsi et al. (2019) and Zimmerle et al. (2019), OGI has emerged as a predominant tool for leak detection in the oil and gas industry. It appears that EPA has transitioned from one effective leak detection method in the final version of NSPS OOOOa, which offered cost-effective relief, to imposing seemingly unrealistic emission factors for whole gas leakers in this proposed version of Subpart W. This shift raises concerns that EPA may be penalizing those who rely on OGI as their primary leak detection method by limiting the potential for substantial emission reductions and is in direct conflict with NSPS OOOOa.

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[113] Table W-1E, W-3A, and W-4A of 2017 revision of Subpart W

[114] 81 Fed. Reg. 35,824, 35,856-57 (June 3, 2016).

68. EPA should allow the use of annual average GHG mole fraction in Equations W-30 and W-32A for Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage.

EPA should allow the use of annual average GHG mole fraction GHGi in Equations W-30 and W-32A as allowed in Equation W-1A for Pneumatic Controllers. This would better align Equipment Leak calculations with other calculations of Subpart W and be consistent with the initiative of capturing empirical data. GPA suggests the following revisions to the proposed regulatory text:

98.233(q)(2)

Eq. W-30

GHGi = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 <u>or concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas</u>; for LNG storage and LNG import and export equipment, GHGi equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHGi equals 1 for CH_4 and 1.1×10^{-2} CO_2.

98.233(r)

Eq. W-32A

GHGi = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHGi, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression, and underground natural gas storage, and onshore natural gas transmission pipeline, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 <u>or concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas</u>; for LNG storage and LNG import and export equipment, GHGi equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHGi equals 1 for CH_4 and 1.1×10^{-2} CO_2.

69. GPA does not anticipate many reporters will use Calculation Method 2 "Leaker measurement methodology."

EPA proposes Calculation Method 2 to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. While optionality around emission calculations is ideal, GPA notes that this is a very burdensome method, and we do not anticipate this being realistic for reporters to adopt. This is another reason that the proposed OGI leaker emission factors must be revised to not be punitive for using that method.

Due to the constraint of the short commenting period (see Comment 1), GPA was not able to evaluate it thoroughly. We do note, however, that the requirement to "accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a site-specific component-level leaker emission factor" is unreasonable for Pressure

Relief Valves, Open Ended Lines, and Pump Seals. [115] These components do not leak that often, and five measurements (rather than 50) is a more reasonable standard.

We note that many gas plants use Method 21 to detect leaks, and reporters have access to leak measurements in ppm concentrations. EPA should explore translation of these measurements to volumetric emissions (e.g., as described in the 1995 document – EPA Protocol for Equipment Leak Estimates).

70. Subpart W leak survey requirements should be revised to better align with NSPS and NESHAP requirements.

Regarding Subpart W leak survey requirements, EPA must consider revisions that enhance alignment with the NESHAP and NSPS programs. For example, while NSPS programs provide exemptions for components under insulation, Subpart W does not. As such, reporters must choose the OGI leak survey method—which has the highest emission factors—for those components but reporters have no other option. At a minimum, EPA should apply the same monitoring exemptions of the NSPS programs to Subpart W to improve rule alignment and eliminate confusion. To fix this issue, GPA recommends the following revision to the proposed regulatory text:

> *98.233(q)(vi)(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), ~~including~~ except components which are considered inaccessible emission sources as defined in part 60 of this chapter.*

71. Subpart W leak duration assumptions should be revised to align with the NSPS and NESHAP repair requirements.

EPA must remove the requirement to assume a leak persists until the next complete survey if the leaking component is subject to repair requirements under other regulations. For example, under NSPS OOOOa, if a gas plant connector[116] is found to be leaking, it must be reinspected within 90 days of repair. Similar provisions for repair and reinspection are included in NSPS OOOOb and EG OOOOc. For other component types, re-monitoring occurs monthly for the next two months following the repair, and the component is then monitored quarterly. Because NSPS rules and proposed EG OOOOb require repair and monitoring after repair, it makes little sense for Subpart W to force operators to calculate and pay fees assuming a leak persists beyond the repair date. This is overly conservative, it does not align with NSPS and EG requirements, and it does not align with the Inflation Reduction Act mandate to incorporate empirical data. To address this issue, EPA should revise Equation W-30, variable $T_{z,p}$ to allow the end of the leak to be based on when a resurvey of the leaking component confirmed it as repaired. EPA should also provide more clarity in the explanation of determining leak duration.

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[115] Proposed 40 C.F.R. § 98.233(q)(4)(ii).

[116] Connectors are surveyed annually.

98.233(q)(2), equation W-30:

T p,z = The total time the surveyed component "z," component type "p," was assumed to be leaking and operational, in hours, which shall be determined as follows: The start date is when the last survey showed the component was not leaking. If only one survey is conducted in the year, the start date shall be assumed to be the first day of the calendar year. The end date is the date of verified repair or the date of the next survey that shows the component is not leaking. If repair is not verified within the calendar year, the end date is the last day of the year, and the leak must be assumed to persist until the next survey or verified repair shows the component is not leaking. ~~If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year.~~ If multiple leak detection surveys are conducted in the calendar year, ~~assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and~~ sum times for all leaking periods. For each leaking component, account for time the component was not operational (i.e., not operating under pressure) using an engineering estimate based on best available data.

72. For transmission pipeline leaks by population count, there is a mismatch between equation W-32A and the emission factors in Table W-5.

The existing equation W-32A[117] is proposed to be used to calculate emissions from the proposed new source category transmission pipeline leaks by population count. This equation includes GHGi, which "for onshore natural gas transmission compression, underground natural gas storage, and onshore natural gas transmission pipeline, GHGi equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2."[118] This equation also includes EFs,e which is a "[p]opulation emission factor for the specific emission source type, as listed in tables W–1, W–3, and W–5 to this subpart."[119] Table W-5 is called "Default Methane Population Emission Factors," however, and only provides methane emission factors. It is not correct to multiply this emission factor by the methane mole percentage. EPA must revise the equation or the factors, and EPA must also describe if and how CO_2 emissions should be calculated for transmission pipeline leaks by population.

73. EPA should reassess the development of revised gathering pipeline emission factors.

EPA is proposing to change emission factors for gathering pipelines in Table W-1 based on the Lamb et al. (2015) study of distribution pipelines. In particular, the protected steel emission factor is proposed to nearly double from 0.47 to 0.93 scfh/mile.

For gathering pipelines, proposed emission factors are based on using the "Average Methane Leak Rate" from the Lamb Study in place of the GRI/EPA Study. We think EPA made two incorrect judgements when assessing the data. First, there is a significant increase in the mean leak rate due to only a few measured leaks. The three largest leaks measured in the Lamb Study (unprotected steel main, protected steel main, and cast-iron main leaks) accounted for 50 percent of the total leak rate, whereas 90 percent of the measured leaks were less than approximately 3 scfh. The three largest leaks are by far outliers, and

[117] Es,e,i = Counte ∗ EFs,e ∗ GHGi ∗ Te (Eq. W-32A).
[118] 88 Fed. Reg. at 50,408.
[119] *Id.*

significantly increase the average emission rates for the respective material. As an example, removal of the large, protected steel leak reduces the average leak rate and emission factor by approximately 60 percent.

Second, EPA only used leak data from distribution mains in the Lamb Study and excluded leak data from services noting that "the emission factors for gathering pipelines by pipeline material are based on the leak rates for distribution mains by pipeline material."[120] GPA does not support separating mains and services when identifying emission factors based on pipeline material. Gathering pipelines are not segregated like distribution pipelines and do not carry main or service designations. As such, it is not appropriate to represent gathering pipelines with only a portion of data collected on distribution pipelines from the Lamb Study. All leak measurement data for each pipeline material should be considered given the pipeline material is the corresponding factor when applying the results of the study on distribution pipelines to develop emission factors for gathering pipelines. Additionally, the Lamb Study notes, "it was not always possible to clearly define a main versus a service leak when the leak occurred at the junction between main and service." The uncertainty distinguishing between pipeline mains and services provides more support to analyze the leak measurements from pipeline mains and services together. When data from mains and services are assessed together, the average leak rate for protected steel drops by approximately 23 percent.

As noted in Comment 16, EPA should consider the PHMSA incident reporting requirements for pipelines. There should be an opportunity to align data on pipeline leaks as an alternative to using an emission factor. For example, if an operator conducts an annual survey of pipelines using advanced screening methods or equivalent methods, that pipeline mileage should be exempt from calculation under the population factors method. This helps to ensure that pipeline emissions are not double counted under both the "Equipment Leaks by Population Count" and "Other Large Release Event" source categories, which, as this rule is proposed, they likely would be. Alternatively, at a minimum, operators should be able apply a control efficiency to the pipeline population emission calculation if pipeline monitoring surveys are conducted. This would also align with the directive in the Inflation Reduction Act to report emissions based on empirical data, where available.

Finally, as described in Comment 20, EPA must address how reporters are to determine if a pipeline leak exceeds the thresholds of 98.233(y)(1)(ii). In other words, EPA must describe how reporters are to determine if any given individual pipeline leak exceeds the emissions calculated under 98.233(r) *Equipment leaks by population count*.

Crankcase Vents

74. Natural gas turbines should be excluded from the crankcase source category.

GPA notes that natural gas turbines do not have crankcase vents, or even an equivalent emission source. As such, EPA should exclude turbines from this proposed emission source category to reduce confusion.

75. Reporters should be allowed to directly measure crankcase vents.

To align with the directive of the Inflation Reduction Act to incorporate empirical data, EPA should allow an option for reporters to directly measure crankcase vent emissions (in addition to the proposed emission factor approach).

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[120] 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 at 108.

We appreciate the simplicity of the emission factor approach option to represent crankcase emissions under Subpart W. It is unclear to GPA, however, if the derivation of the proposed emission factor was based on data from crankcase vents alone, or if the underlying data also incorporated rod packing emissions. GPA also questions the use of the methane composition of fuel gas in the equation (as opposed to methane composition in crankcase vents), which is comprised of an air fuel mixture along with combustion byproducts.

76. GPA seeks clarification on the term "vent" as it relates to crankcase emissions.

EPA proposes that the emission factor of 2.28 scfh be multiplied by the number of vents.[121] GPA seeks clarification on the term "vents" and how to count them, or whether this emission factor was meant to be applied to the whole engine. Vents (or "breathers" as they are sometimes called) can be manifolded together. For example, when installed within a structure, an engine's multiple crankcase vents are typically routed to a central manifold and exhausts to the exterior of the structure through a single "vent." This could be interpreted as an assigned flow value of 2.28 scfh.

77. EPA should allow calculation and reporting options based on each engine instead of facility-wide averages.

The proposed requirements seem to indicate that crankcase venting emissions calculations and reporting are to be conducted based on averages for the whole facility.[122] In practice, reporters will calculate crankcase emissions per engine, and it will be easier if the calculation and reporting requirements are per-engine instead of per-facility. This eliminates an extra step of determining facility-wide total and averages.

Combustion Equipment

78. Methane emissions resulting from combustion are not "waste emissions" for purposes of section 136 of the CAA and should not be subject to the waste emissions fee.

In the preamble to the proposed rule, EPA appropriately distinguishes between "total [methane] emissions" and "waste emissions."[123] This distinction recognizes that not all methane emissions are "waste emissions"—such as any emissions resulting from the operation of equipment intended to actually perform a beneficial function—and should not be included in the definition of methane emissions for purposes of the waste emissions charge. Examples of the types of beneficial functions that should be excluded are methane emissions that result from utilizing natural gas as fuel for engines driving compressors or generators.[124]

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[121] 88 Fed. Reg. at 50,309, 50,413.

[122] *See, e*.g., Proposed 40 C.F.R. § 98.236(ee)(3) ("Average estimated time that the [RICE] or gas turbines with crankcase venting were operational in the calendar year, in hours ("T" in Equation W-45 of this subpart).").

[123] *See, e.g.*, 88 Fed. Reg. at 50,286 (noting CAA section 136 requires Subpart W "accurately reflect the total [methane] emissions *and* waste emissions from the applicable facilities") (emphasis added); *id.* at 50,288 (noting proposed revisions to Subpart W "would ensure that the reporting under subpart W accurately reflects the total [methane] emissions *and* waste emissions as required by CAA section 136(h)") (emphasis added); *see also* CAA § 136(h), 42 U.S.C. § 7436(h) (noting that revisions to Subpart W must ensure data reported "accurately reflect the total methane emissions *and* waste emissions from the applicable facilities") (emphasis added).

[124] These emissions are often colloquially referred to as "methane slip." This term and "combustion exhaust methane emissions" are meant to be used interchangeably throughout these comments.

The text of the Inflation Reduction Act, as codified in section 136 of the CAA, supports this distinction as well. Specifically, section 136(a)(3)(B) clearly distinguishes between emissions that result from beneficial use and waste emissions, as it provides funding for "improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions *and waste.*"[125] Section 136(a)(3)(C) also makes this distinction, providing funding for "supporting innovation in reducing methane and other greenhouse gas emissions *and waste* from petroleum and natural gas systems."[126]

The Bureau of Land Management also recognizes this distinction. In a recent proposed rule, the Bureau explicitly specified that waste is associated with venting, flaring, and leakage.[127] Emissions resulting from stationary combustion are fundamentally different. Rather than being "wasted," gas at those sources is used to fuel critical energy infrastructure. Congress knew how to address methane emissions from beneficial uses and how to address waste emissions, and it did both of those things in the Inflation Reduction Act.[128] Further, Congress made clear that the methane fee provision was intended to apply to waste emissions only.

The distinction between methane emissions resulting from beneficial uses and waste emissions also makes sense because it recognizes that the majority of combustion exhaust methane emissions result from industry reducing criteria pollutant emissions such as NOx and CO by switching combustion engines to lean-burn technologies. Methane emissions are inherent to a low-NOx/low-CO combustion process and lack any current feasible or practical means of control. State gas capture programs such as those in New Mexico[129] and North Dakota[130] recognize this and deem gas used for combustion as beneficial use. These state gas capture programs do not count fuel gas or fuel gas combustion products against gas capture target requirements and certainly do not deem it waste.

While EPA certainly implies in the proposed rule that there is a distinction between methane emissions resulting from combustion and waste emissions, it should explicitly make this distinction in the final rule.

79. The only appropriate subpart for reporting combustion emissions is Subpart C, not Subpart W.

In the proposed rule, EPA asks whether combustion emissions for petroleum and natural gas systems should be moved exclusively to Subpart W.[131] GPA strongly believes that all combustion emissions for petroleum and natural gas systems should be reported under Subpart C. Every other industry reports its combustion emissions under Subpart C (addressing General Stationary Fuel Combustion Sources), while the petroleum and natural gas industry has historically been arbitrarily split between Subparts C and W. This has never made good sense, and GPA urges EPA to place all combustion emissions for petroleum and natural gas systems into Subpart C, which would bring the industry in line with other industries. There is no difference between combustion emissions from other industries and those from the petroleum and natural gas industry. Therefore, treating the petroleum and natural gas industry differently is arbitrary and capricious. In the event that EPA nevertheless decides to move forward with placing combustion emissions for the industry into Subpart W (which GPA urges EPA not to do), then

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[125] CAA § 136(a)(3)(B), 42 U.S.C. § 7436(a)(3)(B) (emphasis added).
[126] *Id.* § 136(a)(3)(C), 42 U.S.C. § 7436(a)(3)(C) (emphasis added).
[127] 87 Fed. Reg. 73,588 (Nov. 30, 2022).
[128] *See, e.g.*, *Hamdan v. Rumsfeld*, 548 U.S. 557, 578 (2006) ("A familiar principle of statutory construction … is that a negative inference may be drawn from the exclusion of language from one statutory provision that is included in other provisions of the same statute.").
[129] New Mexico Administrative Code § 19.15.28.8.F(3)(a).
[130] North Dakota Industrial Commission Order 24665(4)(b).
[131] 88 Fed. Reg. at 50,358.

GPA believes that combustion emissions should not be considered "waste" emissions subject to the Methane Fee. GPA's reasons for these recommendations are discussed in further detail below.

In the Inflation Reduction Act, Congress applied the waste emissions charge to an "applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year *pursuant to subpart W*."[132] Although many emissions from sources covered by Subpart W could reasonably be deemed to be waste emissions and thus subject to the waste emissions fee, methane emissions from combustion sources are a true outlier because they are not, in fact, "wasted." As such, they should not be subject to reporting under Subpart W. Instead, the most appropriate way to address this issue is to revise Subpart W to redirect stationary combustion emissions to Subpart C. As described below, such action would be consistent with the intent behind CAA section 136, and it would rectify a longstanding discrepancy with Subpart W.

Subpart W was originally promulgated on November 30, 2010, with the express intent to add requirements for facilities that contain petroleum and natural gas systems to report equipment leaks and vented GHG emissions under the GHGRP. EPA later amended Subpart W on October 22, 2015, to include the addition of calculation methods and reporting requirements for GHG emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. Stationary combustion emissions are not equipment leaks or vented emissions and as such would be more appropriately reported under Subpart C.

It would also be arbitrary and capricious for EPA to continue requiring the reporting of stationary combustion emissions under Subpart W for the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution segments when all other segments of the petroleum and natural gas industry and *all other industries with fuel combustion emissions* report under Subpart C.[133] The GPA Comments on the 2022 Proposed Rule also addressed this issue.[134]

EPA seeks comment "on amending subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under subpart W."[135] EPA claims that "the increase in total CH_4 emissions from combustion devices at facilities subject to subpart W would be less than 5 percent." As an initial matter, the change in combustion emissions reported under Subpart W is irrelevant when determining where these emissions should be reported. Even if it were relevant, GPA

[132] CAA § 136(c), 42 U.S.C. § 7436(c) (emphasis added).
[133] Industries that report combustion emission under Subpart C include: Subpart D Electricity Generation, Subpart E Adipic Acid Production, Subpart F Aluminum Production, Subpart G Ammonia Manufacturing, Subpart H Cement Production, Subpart I Electronics Manufacturing, Subpart K Ferroalloy Production, Subpart L Fluorinated Gas Production, Subpart N Glass Production, Subpart O HCFC-22 Production And HFC-23 Destruction, Subpart P Hydrogen Production, Subpart Q Iron And Steel Production, Subpart R Lead Production, Subpart S Lime Manufacturing, Subpart T Magnesium Production, Subpart U Miscellaneous Uses Of Carbonate, Subpart V Nitric Acid Production, Subpart X Petrochemical Production, Subpart Y Petroleum Refineries, Subpart Z Phosphoric Acid Production, Subpart AA Pulp And Paper Manufacturing, Subpart BB Silicon Carbide Production, Subpart CC Soda Ash Manufacturing, Subpart DD Electrical Transmission And Distribution Equipment Use, Subpart EE Titanium Dioxide Production, Subpart FF Underground Coal Mines, Subpart GG Zinc Production, Subpart HH Municipal Solid Waste Landfills, Subpart II Industrial Wastewater Treatment, Subpart SS Electrical Equipment Manufacture Or Refurbishment, and Subpart TT Industrial Waste Landfills.
[134] GPA Comments on 2022 Proposed Rule at 25.
[135] 88 Fed. Reg. at 50,358.

was unable to find support for this claim. It is difficult to imagine that this is the case, especially considering the proposed changes to RICE emission factors.

For the reasons stated here and for the reasons stated in the GPA Comments on the 2022 Proposed Rule, EPA should revise Subpart W to move combustion sources for *all* industry sources to Subpart C. If EPA is unwilling to move these emissions to Subpart C, however, GPA recommends that EPA make explicit in the final rule that natural gas used for stationary combustion is a beneficial use that is not subject to the waste emissions charge (or that the methane emissions that result from the combustion of the natural gas are deemed as unavoidably lost and thus not subject to the charge).

80. The use of stack testing results for engines and natural gas turbines should not be restricted to units that use pipeline-quality fuel.

Stack testing results for engines and natural gas turbines that use non-pipeline quality fuel should also be allowed to determine methane slip emissions. EPA noted in the preamble that "fuel types covered by the methods in existing 98.233(z)(2) (proposed 98.233(z)(3)) are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." [136] GPA suggests if an annual performance test is already required for the engine or turbine under another applicable federal standard (e.g., NSPS Subpart JJJJ or NSPS Subpart KKKK), or if the operator voluntarily performs an annual performance test, EPA should allow the results of those tests to be used to determine a methane slip emission factor. While there may be variability in the gas composition, an annual schedule of performance testing will account for changes in gas composition from year to year. This rationale is supported by engine and turbine testing requirements under both NSPS and NESHAP compliance programs.

Additionally, using annual stack data would be consistent with section II.B and C of the proposal's preamble. Annual performance testing results provide additional empirical data to report emissions more accurately and would improve verification and transparency of the data since the tests would follow strict EPA reference methods. EPA should include the option to allow an operator to utilize annual performance testing results for any fuel quality.

81. EPA should allow for annual performance testing results instead of a one-time performance test for methane slip.

EPA proposed a one-time performance test to establish a methane slip emission factor for engines and turbines. [137] Many of the engines and turbines, however, are already subject to annual performance testing under federal or state rules that utilize the same methodology required under the proposed rule. EPA should make clear that the operator may use the most recent performance test data to establish the methane slip emission rate since it would provide the best data and reflect current emissions. As engine and turbine technology evolves, there may be additional ancillary equipment added to an engine or turbine that may improve its emissions, and EPA should allow the operator to establish a new emission rate. This suggestion is consistent with section II.B and C of the preamble while not placing an additional burden on operators that are already completing these performance tests to comply with existing standards and regulatory requirements.

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[136] *Id.* at 50,357.
[137] *Id.* at 50,356.

82. GPA supports EPA's proposed option allowing reporters to use OEM data to calculate and report methane slip emissions for RICE and natural gas turbine engines.

A review of methane emissions data from engine specification sheets published by leading OEMs of RICE and natural gas turbine engines indicates that OEM equipment specification sheet data are consistent with EPA's methane emissions factors presented in Table W-7, which are in turn based on stack test data compiled and critically reviewed by various research organizations, universities, and institutions.

A review of engine specification sheets published by Caterpillar for its line of four-stroke lean-burn ("4SLB") RICE shows that methane slip emissions from these engines are estimated to range from 0.429 to 0.740 kilograms of methane per million British thermal unit ("kg CH_4/mmBtu") depending on an engine's horsepower rating and number of cylinders. A prevalent 4SLB natural gas compressor engine, the Caterpillar 3516B, has an emissions rate of 0.429 kg CH_4/mmBtu at 100 percent load. These data are consistent with 0.522 kg CH_4/mmBtu, EPA's emission factor for 4SLB engines presented in Table W-7 of the Rule.

Additionally, a review of engine specification sheets published by Waukesha for its line of four-stroke rich-burn ("4SRB") RICE shows that methane emissions from these engines are estimated to range from 0.041 to 0.062 kg CH_4/mmBtu depending on the engine's horsepower rating and number of cylinders. A prevalent 4SRB natural gas compressor engine, the Waukesha L7042GSI, has an emissions rate of 0.041 kg CH_4/mmBtu at 100 percent load. These data are consistent with 0.045 kg CH_4/mmBtu, EPA's emission factor for 4SRB engines presented in Table W-7 of the Rule.

Collectively, methane emissions data from these leading OEMs of natural gas compressor engines support the concept that OEM specification data can be used by reporters to reliably estimate and report actual methane slip emissions for GHG inventory purposes.

83. EPA should account for combustion exhaust control in emission calculations.

GPA emphasizes that operators are actively pursuing emission reduction methods, such as considering options to capture and prevent the release of combustion exhaust. However, the current proposed rule overlooks the ability for reporters to account for these innovative emissions control measures. EPA should modify combustion emission calculations to enable reporters to accurately represent novel emission control approaches and incentivize all potential emission reduction. This allowance directly aligns with the goal of the Inflation Reduction Act and incentivizes absolute emission reductions.

Industry Segment-Specific Reporting Elements

84. The requirement to use a flow meter to determine quantities sent to sale or through the facility is not workable for hydrocarbon liquids.

EPA proposes that:

> Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using a flow meter that meets the requirements of 98.234(b) for quantities that are sent to sale or through the facility and determined by using best available data for other quantities [98.236(aa)].

98.234(b) is limited to "flow meters, composition analyzers and pressure gauges," and as such, this proposal is not workable for hydrocarbon liquid throughputs. Liquid throughputs are not always (or even commonly) measured with flow meters but are instead usually determined by truck loading tickets. To address this issue, EPA must expand the allowable methods to measure liquid sales/throughputs.

85. Additional changes are needed to properly account for gathering and boosting throughput.

EPA's proposed changes to the gathering and boosting throughput reporting requirements are an improvement upon the current rule. Two additional changes, however, are needed. First, the term "downstream endpoint" is too narrow because gas sometimes exits the gathering system to an "upstream" location, such as when some gas goes back to upstream producers for various uses. Second, as GPA noted to EPA in both the GPA Comments on Methane Emissions Reduction Program and the GPA Comments on the 2022 Proposed Rule, it is critical for gathering and boosting segment reporters to account for gas that flows through multiple compressor stations in series within the same basin.[138] The proposed language is closer to directly accounting for this, but still falls short of clarity on this important point. As a result, GPA proposes the following changes be made:

> *98.236(aa)(10)(ii) The quantity of natural gas transported through the facility to a downstream endpoint or to another industry segment such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting site or facility in the calendar year, in thousand standard cubic feet.*

> *98.236(aa)(10)(iv) The quantity of all hydrocarbon liquids transported to a downstream endpoint or to another industry segment such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting site or facility in the calendar year, in barrels.*

86. EPA must clarify that non-operational sites do not need to be reported.

Proposed 98.236(aa)(10)(v) requires new reporting elements for "each gathering and boosting site located in the facility." EPA should clarify that reporters are not required to report this site information for sites that are shutdown, bypassed, or otherwise have no potential for emissions. As currently drafted, the regulatory text is unclear on this point and proposed 98.236(aa) compounds the uncertainty by specifying that "[i]f a quantity required to be reported is zero, you must report zero as the value."

Other Technical Comments

87. EPA unnecessarily mandates reporting under Subpart B in 98.232(n) because Subpart B reporting applicability is already specified in that Subpart.

The following proposed language is unnecessary and should not be added unless all other GHGRP subparts are also modified to include analogous language. As noted below, GPA recommends striking this language entirely in the final regulatory text:

> ~~*98.232(n) For all facilities meeting the applicability provisions under § 98.2 and, if applicable, §98.231, report the information required under subpart B of this part (Metered, Non-fuel, Purchased Energy Consumption by Stationary Sources).*~~

[138] GPA Comments on Methane Emissions Reduction Program at 6; GPA Comments on 2022 Proposed Rule at 31.

Top-down measurements and inventory

88. Although GPA supports the use and development of advanced technologies to detect emissions, these technologies are not yet ready to supplant or be incorporated into bottom-up inventories.

EPA has invited feedback on various aspects of what are commonly referred to as "top-down approaches" for the detection and quantification of emissions from petroleum and natural gas systems, particularly for Subpart W reporting. [139] GPA supports the advancement of cutting-edge technologies, such as satellite, aerial, and continuous monitoring systems. Several GPA member companies actively collaborate with technology vendors and research partners to pilot, evaluate, and refine these innovative methods. We also appreciate EPA's willingness to explore alternative approaches to GHG reporting beyond rigid, prescriptive requirements.

Nevertheless, it is essential to recognize that these technologies are still in the early stages of development, especially with regard to the quantification of emissions and the comprehensive assessment of inventories. Brown et al. (2023) compared two independent top-down full-facility estimates to contemporaneous daily inventories assembled by the facility operators at 15 midstream natural gas facilities in the U.S. and found that:

> Significant disagreement was observed at most facilities, both between the two [top-down] methods and between the [top-down] estimates and operator inventory. These findings have two implications. First, improving inventory estimates will require additional on-site or ground-based diagnostic screening and measurement of all sources. Second, the [top-down] full-facility measurement methods need to undergo further testing, characterization, and potential improvement specifically tailored for complex midstream facilities.[140]

While GPA fully embraces the integration of new technology for GHG emission detection, it is crucial to acknowledge that any methods employed in the GHGRP must be well-established. These technologies have not reached that level of maturity yet. At present, the quantification of emissions through remote detection and their integration into inventories remains more of an art than a well-defined process. Our industry is actively exploring how emission detection data can be incorporated into inventories, but substantial progress is needed—particularly before these technologies and methodologies can serve as a foundation for a methane fee.

Furthermore, EPA's assertion that "top-down monitoring methods … measure large emission events" is not correct.[141] These technologies primarily identify specific information, such as the "absorption of reflected sunlight by methane molecules," and subsequently employ data analyses and various algorithms to derive an estimate of emission rates.[142,143] It is critically important for both EPA and the general public to understand this crucial distinction and refrain from assuming that these technologies

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[139] 88 Fed. Reg. at 50,291.
[140] J. Brown, et al., "Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities," ENVIRONMENTAL SCIENCE & TECHNOLOGY, (Feb. 13, 2023), https://pubs.acs.org/doi/10.1021/acs.est.3c01321.
[141] 88 Fed. Reg. at 50,291.
[142] Kairos Aerospace, "Methane Detection from a Unique Perspective," https://kairosaerospace.com/methane-detection/.
[143] K. Branson, et al., Kairos Aerospace, Methane Emissions Quantification, https://kairosaerospace.com/wp-content/uploads/2021/03/Kairos-Emissions-Quantification-v7.4.pdf.

directly or accurately "measure emissions." In reality, they provide indirect estimations, and many of these technologies can only estimate emissions for specific, brief moments in time.

Burden

89. Flawed assumptions in EPA's "Assessment of Burden Impacts" could significantly downplay the proposed rule's impact.

Significant problems in the burden assessment and associated Information Collection Request ("ICR") include the following:

- EPA did not provide labor estimates for emission sources[144] that are already reported under the rule; however, many (if not all) sources have changed data collection, calculation, or reporting requirements under the proposal that impact labor.
- The EPA's estimation of operations and maintenance ("O&M") costs covers only select monitoring requirements, neglecting, for example, the flare monitoring requirements they propose must be implemented for a reporter to claim 98 percent destruction efficiency, or performance test monitoring for combustion methane slip. EPA must address the fact that reporters will need to incur these costs to be allowed to calculate lower methane emissions and reduce their methane fees.
- It appears EPA only included costs related to revisions to reporting and recordkeeping requirements for just <u>four</u> specific revisions.[145] Perhaps this is due to the unclear presentation of the information, but GPA struggles to believe that EPA estimated <u>zero cost</u> associated with the dozens and dozens of changes to 98.236 reporting requirements. If EPA indeed failed to account for costs associated with the extensive changes to reporting requirements, however, this massive gap in cost impacts must be addressed.

To highlight the assessment's overall deficiencies by way of example, the only cost EPA accounted for with regard to flares was "Purchase and installation of continuous parameter monitoring systems" [Table A-3]. EPA does not estimate costs associated with collecting and otherwise using this data. EPA does not estimate costs for periodic flare pilot monitoring. EPA does not estimate costs for the significant exercises of estimating fraction of total volume flared that was received from another facility solely for flaring [98.236(n)(10)] and estimating disaggregated CH_4, CO_2, and N_2O emissions attributed to each source type [98.236(n)(19)]. EPA must explain why certain labor, O&M, and capital costs associated with non-optional rule provisions were excluded from this assessment.

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[144] The document also incorrectly characterizes "Malfunctioning dump valves on atmospheric storage tanks" and "combustion slip" as new emission sources. These sources are currently reported under the GHGRP with different requirements.

[145] EPA, Memorandum from S. Bogle to Docket ID No EPA-HQ-OAR=2023-0234, Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems (June 2023) at Table A-4 (analyzing the burden and costs of only the following four items: (1) Changing reporting basis to the well-pad instead of the basin, (2) Changing reporting basis to the site ID instead of the county or sub-basin, (3) Gathering quantities related to plugged wells (quantities of natural gas, crude oil, and condensate produced that is sent to sale), (4) Monitoring and reporting the quantities of natural gas, crude oil, condensate, residue gas, liquefied natural gas, hydrocarbon liquid, etc. that are sent to sale in the calendar year).

For the costs that are included, specific incorrect assumptions[146] include:

- *ICR, Table 2 (O&M). Centrifugal and Reciprocating Compressors—contractor to perform compressor leak measurements. Onshore Petroleum and Natural Gas Gathering and boosting reporters.*

  EPA assumption 51: "Assumed an average of 6 compressors per reporter (based on average number of reciprocating compressors per reporter from RY2019). NOD measurements are only required once every 3 years, so 2 compressors per year over the 3 year period of the ICR."[147]

  GPA comment: The average number of reciprocating compressors per gathering and boosting reporter in 2021 was 50.2.[148] The average number of centrifugal compressors per gathering and boosting reporter in 2021 was 4.4.[149] This should be 18.2 occurrences/respondent/year which increases the burden by nearly $3.5MM.

- *ICR, Table 1 (Labor). Dump valves 1. Onshore Petroleum and Natural Gas Gathering and boosting reporters.*

  EPA assumption: 1.6 occurrences/respondent/year and 22 respondents/year.[150]

  GPA comment: The burden to be assessed should be the requirement to inspect dump valves, not the number of malfunctioning dump valves. Nearly every tank will have at least one dump valve upstream of it. As such, EPA's assumptions must be adjusted to reflect the number of tanks reported under gathering and boosting. In 2021, for gathering and boosting, 31,543 tanks were reported under calculations methods 1 or 2,[151] and 7,544 tanks were reported under calculation method 3.[152]

- *ICR, Table 1 (Labor). Combustion Emissions. Determine fuel consumption through company records and calculate emissions (to incorporate combustion slip). Onshore Petroleum and Natural Gas Gathering and boosting reporters.*

  EPA assumption 72: "Assumed an additional 0.5 hours per year to incorporate combustion slip into existing calculations."[153] EPA also assumes 1 occurrence/respondent/year and 354 gathering and boosting respondents/year. EPA did not assume any costs for Natural Gas Processing.

  GPA comment: First, EPA failed to estimate burden for the industry segments that report their combustion emissions to Subpart C, even though this proposed rule impacts those segments.[154]

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[146] EPA, Supporting Statement: Information Collection Request for the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed rule (June 2023), Docket ID No. EPA-HQ-OAR-2023-0234-0164 ("EPA Supporting Statement").
[147] *Id.* at 32.
[148] Envirofacts GHG Query Builder at Table ef_w_recip_comp_onshore, Field "Compressor Count," *available at* https://enviro.epa.gov/query-builder/ghg.
[149] *Id.* at Table ef_w_centrif_comp_onshore, Field "Compressor Count."
[150] EPA Supporting Statement at 13.
[151] Envirofacts GHG Query Builder at Table ef_w_atm_stg_tanks_calc1or2, Field "Atmospheric Tank Count," *available at* https://enviro.epa.gov/query-builder/ghg.
[152] *Id.* at Table ef_w_atm_stg_tanks_calc3, Field "Atmospheric Tank Count."
[153] EPA Supporting Statement at 33.
[154] 88 Fed. Reg. at 50,357 (noting that "[f]or the subpart W industry segments that estimate and report their combustion emissions to subpart C, we are proposing amendments in subpart C analogous to the proposed

Second, as GPA has previously commented, the requisite fuel allocation that results from these changed requirements is a significant burden. EPA is proposing revisions to 98.36(c)(1) and (c)(3) to clarify that reporters must separately report equipment type (e.g., 4SRB RICE) within the same aggregation of units or common pipe configuration. The calculations necessitate using different CH_4 emission factors per equipment type, and possibly per equipment. This will result in significant burden. At gas plants, it is not common (and is possibly never the case) to have an individual fuel meter on each piece of fuel combustion equipment. Reporters use the Subpart C aggregation/common pipe methods because that aligns with how fuel meters are set up—one meter for multiple pieces of equipment. Disallowing aggregation/common pipe between compressor driver engines and other combustion units will result in much more work, because instead of simply collecting volume and composition for a meter, reporters will have to apportion fuel use for all equipment on the meter. Reporters will have to collect fuel volume, fuel composition, heat rate for each equipment, run hours for each equipment (which is often not automated), and calculate the portion of fuel use per equipment using heat rate and run hours, and multiply that portion by the total fuel volume. While GPA understands that methane emission factors cannot be mixed between equipment types, EPA must at the very least properly account for the increase in burden. We estimate at least 2 hours per year per each aggregation of units/common pipe reported under Subpart C.

For gathering and boosting, EPA assumes that for the dozens (or hundreds) of fuel combustion equipment per reported facility/basin, it will only take 30 minutes to allocate fuel to all equipment (or group of equipment) and incorporate performance test results and/or OEM data. This should be increased to 1 hour per *site* (as the term is proposed), not per gathering and boosting facility/basin.

- EPA does not estimate a burden impact on reporting quantities "sent to sale." EPA proposes, however, that liquid hydrocarbons must quantified with flow meters, which is unworkable (see Comment 84). If EPA does not resolve this issue, the burden assessment must be increased by hundreds of millions of dollars to install liquid flow metering at every site/facility in the industry segment.

90. EPA's cost estimate for Other Large Release Events fails to contemplate the practical realities of this proposal.

The EPA's estimate of $188,688 for the other large release event emission source is far from realistic. The proposal, requiring reporters to assume event durations of 182 days unless proven otherwise, forces significant additional surveillance and technology expenses (see Comment 19). GPA does not argue that additional monitoring can be beneficial for numerous reasons. EPA overlooks these substantial cost implications, however, rendering the burden assessment incomplete.

amendments described in this section for the three industry segments that estimate and report their combustion emissions to subpart W….").

Attachment A

Via e-filing on www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Attention: Docket # EPA-HQ-OAR-2019-0424
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Notice of Proposed Rulemaking "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36,920 (June 21, 2022), Docket # EPA-HQ-OAR-2019-0424

Dear Docket Clerk,

Thank you for the opportunity for GPA Midstream to provide comments to the U.S. Environmental Protection Agency ("EPA" or the "Agency") on the Agency's proposed rule, titled "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36,920 (June 21, 2022) ("Proposed Rule").

GPA Midstream has served the U.S. energy industry since 1921 and has over 60 corporate members that directly employ more than 60,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids ("NGLs"), refined products and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 320,000 jobs across the U.S. economy. GPA Midstream members recover more than 80% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 380 natural gas processing facilities. In the 2018-2020 period, GPA Midstream members spent over $90 billion in capital improvements to serve the country's needs for reliable and affordable energy.

GPA and its members have participated in each EPA rulemaking to address greenhouse gas ("GHG") emissions from the oil and natural gas midstream industry, including the initial development of the greenhouse gas reporting program ("GHGRP") in 2009. Since that time, GPA has continued to work with EPA to improve, streamline, and clarify the requirements of 40 C.F.R. Part 98. We appreciate that many of the proposed rule revisions respond to information GPA has previously submitted to EPA.

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Other aspects of the proposed rule would benefit from further clarification or additional consideration. These comments provide GPA's views on these matters. We hope EPA finds the enclosed information useful. GPA welcomes the opportunity to continue discussions with the Agency as it develops its revisions to the GHGRP.

Sincerely,

Matthew Hite

Matthew Hite

Comments of GPA Midstream Association on

The U.S. Environmental Protection Agency's Proposed Rule: "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule"

87 Fed. Reg. 36,920 (June 21, 2022)

Docket ID No. EPA-HQ-OAR-2019-0424

October 6, 2022

Comments of GPA Midstream Association on

the U.S. Environmental Protection Agency's Proposed Rule: "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule"

87 Fed. Reg. 36,920 (June 21, 2022)

Docket ID No. EPA-HQ-OAR-2019-0424

GPA Midstream Association (GPA) appreciates this opportunity to submit comments on the proposed rulemaking "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36,920 (June 21, 2022). The proposed rule notice summary indicates that the proposed rule is intended "to improve the quality and consistency of the data collected under the rule, streamline and improve implementation, and clarify or propose minor updates to certain provisions that have been the subject of questions from reporting entities."

GPA Midstream has served the U.S. energy industry since 1921 and has over 60 corporate members that directly employ more than 60,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids ("NGLs"), refined products and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 320,000 jobs across the U.S. economy. GPA Midstream members recover more than 80% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 380 natural gas processing facilities. In the 2018-2020 period, GPA Midstream members spent over $90 billion in capital improvements to serve the country's needs for reliable and affordable energy.

GPA and its members have participated in each EPA rulemaking to address greenhouse gas ("GHG") emissions from the oil and natural gas midstream industry, including the initial development of the greenhouse gas reporting program ("GHGRP") in 2009. Since that time, GPA has continued to work with EPA to improve, streamline, and clarify the requirements of 40 C.F.R. Part 98. We appreciate that many of the proposed rule revisions respond to information GPA has previously submitted to EPA. We also appreciate EPA's efforts to find additional ways to reduce reporter burden beyond the specific requests that GPA has previously made. For these reasons, GPA supports many elements of EPA's proposed rule, as described in these comments, and encourages the Agency to include those provisions in its final rule.

Other aspects of the proposed rule would benefit from further clarification or additional consideration. GPA notes there are over 150 discrete changes that would impact natural gas gathering and boosting ("G&B") and natural gas processing reporters.[1]

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

Table of Contents

I. One Rulemaking for Subpart W Changes

The Inflation Reduction Act requires EPA to, within the next two years, revise subpart W to support methane fee implementation and allow reporters to submit empirical data**.**[2] That rulemaking is likely to involve substantial changes to the GHGRP and will need to be executed expeditiously to meet the legislative deadline. As such, GPA suggests that EPA not change subpart W at this time and instead issue one comprehensive subpart W rule package to accomplish the goals of this proposal along with methane fee implementation. This will reduce reporter burden by avoiding **the** "whiplash" of making changes for one expansive subpart W rulemaking only to make another set of changes in short order. Not only do we support this for resource efficiency, but GPA also supports the use of direct measurement and testing **as an option**, alongside the option to use emission factors derived from empirical data.

We would, however, encourage EPA to proceed with the revision to emission factors for natural gas fired compressor engines, with the request that these combustion sources remain in (or be moved to) subpart C in accordance with our more detailed comments (see section IV. L *Combustion Equipment***)**. As also explained in section IV. L below, when calculating combustion methane emissions, we strongly support the ability to use original equipment manufacturer specific factors, stack test data, a control percentage applied to the emissions, or other empirical data to allow reporters to accurately reflect combustion methane emissions and, importantly, emission reductions.

If EPA does not proceed with updating subpart W in the final version of this rulemaking, we ask EPA to consider this comment letter when crafting the next subpart W proposed rule.

II. GPA Supports Many of EPA's Proposed Changes to the GHGRP

As noted above, GPA has worked extensively with EPA over the years on potential revisions to the GHGRP, and a significant number of the provisions EPA has proposed reflect policies consistent with positions GPA has advocated and technical data and other information GPA has developed and supplied to EPA. GPA is pleased to have been a part of this productive process and encourages EPA to finalize provisions, consistent with these comments, that GPA believes will provide for a more effective and efficient GHGRP.

The following is a list of substantive proposed changes that GPA expressly supports. In the preamble to the proposed rule, EPA has thoroughly and thoughtfully explained the reasons for the following changes, which include explanations of the existing requirements, data previously reported, feedback from individual reporters, and feedback from GPA. In addition to the highlighted changes listed below, GPA also includes Appendix A to these comments, which is a table of other proposed changes that GPA supports.

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[2] "Not later than 2 years after the date of enactment of this section, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed." Inflation Reduction Act § 60113 (2022).

- Removal of the requirement to measure each compressor in the not-operating-depressurized mode every three years [98.233(o)(1)(i)(C) and (p)(1)(i)(D)]
- Alignment of the onshore natural gas processing definition with NSPS OOOOa through targeted consistency changes [40 CFR 98.230(a)]
- Removal of the 25 million standard cubic feet ("MMscf") per day threshold in the definition of natural gas processing [40 CFR 98.230(a)]
- Streamlining reporting of hydrocarbon liquid throughputs under Subparts W and NN [98.236(aa)(3)]
- Addition of reporting element of the count of compressor stations within a basin to facilitate better understanding of G&B operations [98.236(aa)(10)(v)]
    - *Please see comment below with respect to making this count more representative of G&B facilities.*
- For G&B, allowing use of engineering estimates based on best available data to determine the concentration of gas hydrocarbon constituents in the flow of gas to the combustion unit [98.233(z)(3)(ii)(B)]
- Removal of desiccant dehydrators as a distinct emission source [98.233(e)(3)] and inclusion of desiccant dehydrator blowdowns under 98.233(i)
- Including a new option to survey natural gas intermittent bleed pneumatic devices and calculate emissions based on properly functioning devices and malfunctioning devices [98.233(a)(6)]
    - *Please see comment below with respect to "complete" surveys.*
- Allowing use of calibrated bags and high-volume samplers for centrifugal compressor wet seal oil degassing vent measurements [98.233(o)(2)(ii)]
- Removal of redundant reporting requirements of manifolding/controls at both the compressor and leak/vent level [98.236(o)(1)(vi) through (ix) and 98.236(p)(1)(vi) through (ix)]
- Adding total hydrocarbon leaker emission factors for onshore natural gas processing for Method 21 at 500 ppm [Table W-2A]

III. Effective Date of the Final Rule

The Spring 2022 Unified Agenda of Regularly and Deregulatory Actions lists November 2023 as the anticipated date of the final rule. The proposed rule, however, says that EPA "anticipates that the proposed changes may take effect on January 1, 2023, and would apply beginning with reports submitted for RY2023, which are required to be submitted to the EPA by April 1, 2024."[3]

If the final rule is indeed published in 2023, especially late 2023, the effective date should not be any earlier than January 1, 2024. The changes proposed are extensive and will require significant work to implement, work which cannot begin based on speculation while operators wait for the release of a final rule. Especially for midstream reporters, the GHGRP is an extremely complicated rule, and many midstream operators have had to build sophisticated data collection, calculation, and reporting systems to manage the huge workload this rule imposes and conduct thorough training in the field to ensure the data is properly collected. These data systems will have to be updated (and thoroughly tested) to accommodate the significant and substantial changes EPA has proposed for midstream operators. Further, due to the anticipated Securities and Exchange Commission ("SEC") rule relating to environmental, social and governance ("ESG") disclosures, changes to these systems will also require updates to provide stricter assurance and audit requirements. The SEC rule could have other

[3] 87 Fed. Reg. at 36,924.

implications when considering an appropriate effective date for this rule (for example, is BAMM allowable in the context of SEC disclosures?). In fact, even proposed changes intended to simplify or streamline requirements will require modifications to a reporter's GHGRP program and data systems. Many of the data system changes cannot be made until EPA releases final updated reporting forms and XML schema.

In addition, it is important to emphasize that even if a reporter may possess the raw data that will be required by a regulatory change, the necessary data collection, calculation, and reporting work will not be trivial. The opposite will in fact be true in many cases. Given these circumstances, EPA cannot reasonably expect companies to significantly change their GHG reporting programs based on speculation as to what may be included in a final rule, to change their systems retroactively, or to make rapid changes to complex reporting programs. This is unduly burdensome and costly. For these reasons, GPA requests that EPA apply a reasonable effective date and period for implementation of any final rule that will accommodate industry's needs to adapt to EPA's regulatory changes.

IV. GPA Requests Targeted Changes to the Rule and Supporting Material

A. Overarching Comments

Although GPA supports a number of the provisions EPA has proposed, GPA also believes that the proposed rule would benefit from reconsideration and further revision in several significant respects. GPA's recommendations apply to aspects of the proposed revisions to the GHGRP in general, to the general provisions that govern reporting under Subpart W, and to the requirements for individual pieces of equipment and similarly specific requirements of the GHGRP, as modified by the proposed rule.

Reliance on Proposed Standards under Section 111. As a general matter, the proposed rule's reliance on aspects of the proposed new source performance standards ("NSPS") and emissions guidelines for existing oil and natural gas sources under section 111(b) and 111(d), respectively referred to as proposed subpart OOOOb and proposed subpart OOOOc, create logistical and legal concerns for the proposed rule.[4] The proposed rule explains that EPA is "proposing revisions to certain requirements in subpart W relative to the requirements proposed for NSPS OOOOb and the presumptive standards proposed in the EG OOOOc (which would inform the standards to be developed and codified under 40 CFR part 62)."[5] Those revisions include the subpart W calculation methodologies for natural gas pneumatic devices and equipment leak surveys, as well as the reporting requirements for "other large release events."[6] EPA further explains that at least some of these proposed revisions "would not apply to individual reporters unless and until their emission sources are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 …. [and that] [i]n the meantime, reporters would comply with the applicable provisions of subpart W for sources not subject to NSPS OOOOb or 40 CFR part 62."[7]

The Clean Air Act ("CAA") and the most fundamental tenets of administrative law require EPA to propose revisions to the GHGRP that provide adequate notice to interested parties. The Administrative

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[4] *See id*. at 36,962.
[5] *Id*.
[6] *Id*.
[7] *Id*.; *id*. at 36,977-79; 36,983-84.

Procedure Act ("APA"), for instance, requires that a notice of proposed rulemaking include "either the terms or substance of the proposed rule or a description of the subjects and issues involved."[8] Under this standard, an agency's proposal must fairly apprise interested persons of the subjects and issues of the rulemaking.[9]

Section 307(d)(3) of the CAA imposes even more stringent requirements than the APA. It requires a notice of proposed rulemaking to include "the factual data on which the proposed rule is based;" "the methodology used in obtaining the data and in analyzing the data;" and "the major legal interpretations and policy considerations underlying the proposed rule."[10] The D.C. Circuit has explained that the CAA thus requires EPA to issue a proposed rule and to provide a detailed explanation of its reasoning at the proposed rule stage.[11]

Until EPA's OOOOb and OOOOc requirements have been made final, any proposed rule that relies on their requirements cannot reasonably provide notice of "the terms or substance of the proposed rule" or "the major legal interpretations and policy considerations underlying the proposed rule." On the contrary, the references in the proposed revisions to the GHGRP are in effect mere placeholders for whatever law or policy is ultimately made in the related proposals for OOOOb and OOOOc.

Even as a practical matter, EPA should refrain from taking final action on its proposed revisions to subpart W until it has finalized OOOOb and OOOOc and allowed interested parties with an opportunity to fully comment on how those final rules requirements might be reflected in or impact implementation of the GHGRP. Acting to finalize the GHGRP revisions first risks predetermining (or giving the appearance of predetermining) the outcome of the methane and volatile organic compounds ("VOCs") rulemaking or premising the revisions at issue in this rulemaking on provisions that remain subject to change. Either alternative is problematic.

EPA can avoid these issues entirely by taking final action on OOOOb and OOOOc prior to finalizing this rulemaking. Should the OOOOb or OOOOc requirements change in any substantive respect relevant to the GHGRP, EPA should reopen these proceedings for additional public comment. Taking such an approach will ensure that EPA complies with the law and adopts sound public policy.

Use of Best Available Monitoring Methods ("BAMM"). To allow for a successful transition to the requirements of subpart W, as it would be revised under this proposed rule, EPA proposes to allow reporter to use BAMM "for the 2023 reporting year for only the specific industry segments and emission sources for which new monitoring or data collection requirements are being proposed."[12] The reason for allowing the use of BAMM in the manner EPA proposes is to "allow reporters to use best available methods to estimate inputs to emission equations for the newly proposed emission sources using their best engineering judgment for cases where the monitoring of these inputs would not be possible beginning on January 1, 2023."[13] EPA envisions facilities using the period during which the availability of BAMM is in effect (from January 1, 2023 to December 31, 2023, as proposed) "to install the necessary

[8] 5 U.S.C. § 553(b).
[9] *See, e.g.*, *Am. Iron & Steel Inst. v. EPA*, 568 F.2d 284, 293 (3d Cir. 1977).
[10] CAA § 307(d)(3), 42 U.S.C. § 7607(d)(3).
[11] *See, e.g., Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 519 (D.C. Cir. 1983).
[12] 87 Fed. Reg. at 36,995.
[13] *Id*. at 36,995.

monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions."[14] EPA says that it is not proposing to allow the use of BAMM beyond RY2023.[15]

As stated above, GPA does not believe that an effective date of January 1, 2023, is realistic or workable. For that reason, GPA encourages EPA to adopt an effective date of January 1, 2024, and to provide for automatic availability of BAMM for RY2024. If EPA adheres to its plans for a January 1, 2023 effective date, GPA requests that EPA make BAMM automatically available for RY2023 and RY2024. As explained above, the changes to the GHGRP that EPA has proposed are extensive and will require substantial modifications to data collection and reporting systems. As described below, those changes cannot be made until EPA finalizes updated reporting forms and schema. Regardless of the effective date, GPA does not believe that its members will be able to complete the necessary changes to their systems prior to the end of 2024.

Further, completion of the necessary changes and ensuring that the systems are operating correctly may take longer than EPA has initially estimated. Accordingly, GPA requests that EPA provide for optional BAMM in 2025. EPA could require that reporters making a request for BAMM for RY2025 certify that additional time is needed to install necessary monitoring equipment or to otherwise upgrade systems to ensure accurate reporting. Such an approach would be consistent with EPA's goals for the GHGRP, the Agency's past and current policies regarding BAMM, and would allow the regulated community to work with EPA to provide the information the agency hopes to receive.

Schema and Reporting Forms. GPA strongly encourages EPA to provide the draft XML schema and draft revised reporting forms to reporters for review and testing. In the past, doing so has led to the identification of errors and resulted in significant improvements. Additionally, final forms and schema should be published at least 6 months prior to the due date of the first affected reports. Many midstream operators are reporting data for hundreds of assets and have thus developed automated processes for populating forms and/or schema, which will need to be updated to reflect the extensive changes EPA has proposed. In the past, EPA has often not released schema until late January[16] i.e., mere weeks before the reporting deadline, which has compounded challenges during the demanding annual reporting process.

Additional Reform. In the past, GPA has generally advocated for simple emission factors for calculating emissions under the GHGRP rather than reliance on direct measurements. However, as companies look for new ways to reduce greenhouse gas emissions, and as companies seek to finetune their reported emissions accordingly, EPA could best fulfill the purposes of the GHGRP by allowing more methods by which reporters can determine emissions. Most reporters have been submitting GHG reports to EPA for at least 6 years (G&B), if not 12 years (Plants), and GHG reporting programs have come a long way in their maturity. As such, EPA should consider ways to move away from a reporting regime focused on consistent calculation methods among reporters and move toward a reporting regime focused on improving the accuracy of reported emissions. EPA should consider moving toward a "hierarchy" of calculation methods, like how many states structure criteria pollutant emission inventory calculation requirements. This also aligns with the directive in the Inflation Reduction Act to ensure reported emissions are based on empirical data and accurately reflect total emissions. GPA welcomes the

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[14] *Id*.
[15] *Id*.
[16] https://ccdsupport.com/confluence/display/help/Archived+XML+Reporting+Instructions

opportunity to continue discussions with EPA in this regard and encourages EPA to use this rulemaking as an opportunity to gather additional information that will make such a reporting program possible.

EPA's Legal Authority. EPA has consistently stated that the basis for its GHGRP is section 114 of the CAA.[17] In the proposed rule, EPA says that section 114(a)(1) "provides the EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a wide variety of CAA provisions."[18] EPA also continues to point to a 2008 Consolidated Appropriations Act as part of the basis for the GHGRP.[19] That enactment required EPA to publish a proposed and final rule "to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States."[20]

EPA's authority to collect information under section 114 is specifically circumscribed. The Administrator may require the submission of information "[f]or the purpose … of developing or assisting in the development of any implementation plan under" sections 110 or 111 of the CAA, any standard of performance under section 111, and emission standard under section 112, regulations related to solid waste, or for purposes "of determining whether any person is in violation of any such standard or any requirement of such a plan."[21] Section 114 further authorizes the collection of information for the purpose of carrying out any provision of chapter 85 of title 42.[22]

Prior to the promulgation of the GHGRP, EPA had never used section 114 to require the indefinite, if not permanent, gathering and reporting of data. After many years of collecting GHG data pursuant to subpart W, GPA appreciates EPA's efforts to streamline its regulatory requirements and ease reporting burdens. Nevertheless, GPA remains concerned that EPA has not explained, consistent with the limits on the agency's section 114 authority, the reasons for its continuation of the GHGRP, the agency's ultimate regulatory goals, and the information EPA needs to ensure compliance with the rules it has already promulgated. Indeed, for sources that are already subject to emission limits, tailoring reporting requirements to what is needed to determine whether any source is in violation of an applicable standard should be the primary focus of EPA's rulemaking. At the very least, EPA is obligated to fully explain how its proposed rule is consistent with its section 114 authority. GPA encourages EPA to engage this issue in a supplemental proposal or in its final rule.

B. General Comments Pertaining to Subpart W Requirements

The following sections of GPA's comments identify specific requests for information from EPA, proposed changes to regulatory text or other issues raised by EPA's proposed rule and further provides GPA's responses or other comments on the relevant issues. As with all issues addressed in these comments, GPA welcomes the opportunity to provide EPA with additional information or to otherwise respond to any questions that might arise as a result of these comments.

[17] *See, e.g.*, 87 Fed. Reg. at 36,925.
[18] *Id*. at 36,925-26.
[19] *See id*. at 36,924 n.1.
[20] Consolidated Appropriations Act, 2008, Public L. No. 110–161, 121 Stat. 1844, 2128.
[21] CAA § 114(a); 42 U.S.C. § 7414(a).
[22] *Id*.

Request For Comment ("RFC"): EPA proposes to revise the definition of the Onshore Natural Gas Processing segment to largely align with OOOOa and to remove the 25 MMscf per day threshold for facilities that do not fractionate NGLs. EPA requests comment on the impact the proposed definition and throughput threshold changes would have on the number of reporting facilities and emissions from both the Onshore Natural Gas Processing and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. EPA also requests comment on any other advantages or disadvantages to finalizing the proposed change.

> **Comment**: GPA does not anticipate the proposed changes will impact reported emissions significantly. The proposed changes better categorize facilities to align with industry terminology, which will also better align reported emissions with the appropriate industry segments. For the reasons EPA articulated in the preamble, these changes also add certainty for reporters and reduce burden.

RFC: EPA requests comment on whether to remove the existing requirement to include residue gas compression equipment owned or operated by the natural gas processing facility from 40 C.F.R. § 98.230(a)(3) and 40 C.F.R. § 98.231(b). If these changes were finalized, EPA anticipates that residue gas compression equipment would then be part of the Onshore Natural Gas Transmission Compression industry segment.

> **Comment**: EPA should absolutely retain the existing language in 40 CFR § 98.230(a)(3) and 40 CFR § 98.231(b). Residue gas compression equipment owned or operated by the natural gas processing facility is permitted under the natural gas processing facility in state and federal permits and is considered part of the natural gas processing facility under OOOOa (*see* TSD, Proposed 40 C.F.R. 60 subpart OOOOa, page 73, link), where EPA, when describing Natural Gas transmission and storage stations says, "Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment." *See also* 40 C.F.R. § 60.5365a which clarifies that OOOOa applies to an affected facility located with the Crude Oil and Natural Gas Production source category, as defined in 40 C.F.R. § 60.5430a, which defines the Crude Oil and Natural Gas Production source category to mean "Natural gas production and processing, which includes the well and *extends to*, but does not include, *the point of custody transfer to the natural gas transmission* and storage segment."[23] Residue compressors at a gas plant are clearly upstream of the point of custody transfer to the natural gas transmission and storage segment.
>
> Further, there is no reason for EPA to create unnecessary confusion by redrawing the commonly understood boundaries of these industry segments. Doing so would be a mistake and could have considerable unforeseen consequences. Additionally, removing this language, as contemplated by EPA's proposal, would likely decrease reported emissions, as emissions reported at processing plants would decrease, and a handful of plant residue compressors which would be considered "transmission compression" may not trigger the 25,000 mtCO_2e reporting threshold for Onshore Natural Gas Transmission Compression.

[23] 40 C.F.R. § 60.5430a (emphasis added).

C. Natural Gas Pneumatic Device Venting

Proposed Change: EPA is proposing an option to survey natural gas intermittent bleed pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.

Comment: The proposed requirements for natural gas intermittent bleed pneumatic devices are *per device* and not for *all* intermittent bleed pneumatic devices located at an onshore petroleum and natural gas gathering and boosting facility (i.e., an entire basin). This makes sense, because (as proposed by EPA) pneumatic devices would also be individually subject to OOOOb or an applicable approved state plan or applicable Federal plan contained in part 62, and it will be years before all intermittent bleed pneumatic devices in a G&B basin are subject to such requirements. EPA must therefore clarify that the survey requirement for intermittent bleed pneumatics using equation W-1B applies on a device-by-device basis. Alternatively, EPA could clarify that a "complete" survey refers only to a survey of all intermittent bleed pneumatic devices that are complying with the monitoring requirements of § 98.233(a)(6).

Suggested text: *98.233(a)(6)(ii) You must ~~conduct at least one complete~~ survey the pneumatic device ~~monitoring survey~~ at least once in a calendar year. If you ~~conduct multiple complete~~ survey the pneumatic device ~~monitoring surveys~~ multiple times in a calendar year, you must use the results from each ~~complete pneumatic device monitoring~~ survey when calculating emissions using Equation W-1B.*

Proposed Change: EPA is proposing revisions to emission factors for pneumatic devices in the G&B segment.

Comment: GPA supports using recent studies to update these emission factors and believes an update is necessary to ensure emission estimates better align with actual emissions. In the Technical Support Document Table 2-11, EPA presents these proposed emission factors, along with alternative emission factors developed by excluding zero emissions measurements from the studies used to develop the factors. GPA supports using the data from the studies, inclusive of the zero emissions values, and therefore recommends that EPA adopt the emission factors presented in Table 2-11 and not adopt the alternative emission factors. It would not be appropriate to exclude valid data points simply because they indicated zero emissions.

D. Natural Gas Driven Pneumatic Pump Venting

Proposed Change: EPA is proposing that if a pump switches from uncontrolled to controlled during the year, reporters should calculate emissions using both uncontrolled and controlled calculation methods and adjust the time in equation W-2. EPA is also proposing to collect counts of the total number of pumps in addition to the number of controlled pumps and uncontrolled pumps since a pump can be both controlled and uncontrolled during the year.

Comment: This requirement is unnecessarily precise and overly burdensome given the very limited number of sources this provision would apply to, even as operators eliminate or control natural gas driven pneumatic pumps. One of the goals of this rulemaking is to streamline implementation, and a requirement to develop and use a mix of partial-year calculation methods for a small number of sources would introduce unnecessary complexity contrary to

EPA's overarching goals for this rulemaking. This proposed change would also imply that emissions must be calculated *per pump* instead of *per collection of pumps* as equation W-2 otherwise allows. To address these issues in a reasonable and accurate manner, GPA proposes that sources apply the calculation method that represents operation during the majority of the year.

Similarly, collecting data on the total number of pumps in addition to the number of controlled pumps and uncontrolled pumps for the purposes understanding "how often pneumatic pumps are both controlled and vented directly to the atmosphere in the same year" is overly burdensome and unnecessary. Uncontrolled pumps that become controlled will generally switch mid-year (i.e., not on January 1), and will switch just once. Pumps will not move in and out of being controlled throughout the year. Simply collecting the number of controlled pumps and uncontrolled pumps and assessing changes over time should provide sufficient information for EPA to understand pump control changes.[24]

Suggested text:

98.233(c) Natural gas driven pneumatic pump venting. Calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section. Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3) of this section. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, calculate emissions based on how the pump operated most of the year. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

98.233(c)(3) Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraphs (c)(3)(i) or (ii) of this section, as applicable. ~~If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then calculate emissions from the time the pump vents directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section and calculate emissions from the time the pump was routed to a flare or combustion as specified in paragraphs (c)(3)(i) and (ii) of this section, as applicable~~. For emissions that are collected in a vapor recovery system that is not routed to combustion, paragraphs (c)(1), (2), (3)(i), and (3)(ii) do not apply and no emissions calculations are required.

RFC: EPA requests comment on whether pneumatic pumps are routed to vapor recovery systems and whether there are other controls that should be addressed with these new provisions.

Comment: GPA members were not aware of examples of pneumatic pumps being routed to vapor recovery systems; the emissions from pumps are typically too low to justify using a vapor recover unit for control. GPA members are not aware of other control methods for pneumatic pumps other than flares or combustion.

[24] Indeed, it is questionable whether this information is truly useful and otherwise consistent with the scope of the GHGRP generally, EPA's regulatory needs, or the authority granted under section 114.

RFC: EPA requests comment on whether flared emissions associated with natural gas driven pneumatic pumps should continue to be reported as flare stack emissions under 40 C.F.R. § 98.236(n) or should be reported in the natural gas driven pneumatic pumps emission source under 40 C.F.R. § 98.236(c).

> **Comment**: These emissions should continue to be reported under section 98.236(n). This source is too small to justify the work of parsing out its emissions from the total flare emissions.

E. Acid Gas Removal Units ("AGRUs")

Comment: For AGRUs, EPA is still requiring that, if present, acid gas vent meter data must be used [Calculation Method 2, 98.233(d)(2)]. EPA should make this method optional. The acid gas vent is a difficult stream to measure. Good measurement can be achieved on streams that have controlled flow rates with decent pressure and consistent composition. This is often not the case on acid gas vents (which tend to have varying flow rates, varying composition, and low pressure). Additionally, Calculation Method 2 requires quarterly sampling of sour gas. This is a difficult sample to take because of the inherent safety concerns (high H_2S), and therefore many facilities would only sample it quarterly to comply with this rule. In contrast, plant inlet and residue gas are generally sampled frequently, and as such, Calculation Methods 3 or 4 may yield more accurate emission estimates than Calculation Method 2.

> **Suggested text**: *98.233(d)(2) Calculation Method 2. If a CEMS is not available but a vent meter is installed, you may use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.*

F. Dehydrators

Proposed Change: EPA is proposing to collect many new reporting elements for glycol dehydrators: flash tank control technique, regen still vent control technique, flash tank vent gas flow rate, regenerator still vent gas flow rate, concentrations of CH_4 and CO_2 in flash tank vent gas, concentrations of CH_4 and CO_2 in regenerator still vent gas, type of stripping gas used, and flow rate of stripping gas [98.236(e)].

> **Comment**: EPA should strike these new requirements. GPA originally asked EPA to develop an emission factor for dehydrators with throughputs greater than 0.4 MMscf per day but less than 3 MMscf per day. We requested an emission factor because this group of glycol dehydrators does not generally have an obligation to run an annual emission simulation other than for compliance with the GHGRP (dehydrators with throughput greater than 3 MMscf per day run an annual emission simulation to comply with NESHSAP HH), and running these additional simulations solely for GHGRP compliance was time consuming and burdensome. However, EPA recently approved use of BRE Promax simulations (which accommodates bulk runs and provides data exports in GHGRP "friendly" format) for NESHAP HH compliance. This change streamlines running dehydrator simulations for the GHGRP, and GPA members can more easily include these small dehydrators into annual process simulations. As such, GPA is no longer requesting an emission factor for these small dehydrators, and EPA's additional data requests are unnecessary. More importantly, all of these additional reporting requirements add burden and complexity, and EPA does not need to understand the precise details of dehydrators (an already well-regulated emission source) to collect and validate the reported greenhouse gas emissions.

RFC: EPA requests comment on advantages and disadvantages of an alternative to require reporting on devices with desiccant that absorb water under a desiccant dehydrator emission source.

> **Comment**: The distinction between these two equipment types ("devices with desiccant that absorb water" vs "devices containing materials that absorb water") is very subtle and not generally understood by reporters. A Google search will show that molecular sieve dehydrators are often called desiccant dehydrators. EPA should not retain a reporting source for "devices with desiccant that absorb water." As noted by EPA, this is a small emission source, and retaining this source will only result in continued confusion by reporters on which non-glycol dehydrators to report or not report.

G. Blowdown Vent Stacks

Proposed Change: EPA is revising the descriptions of "facility piping" and "pipeline venting" in attempt to reduce confusion about categorizing pipeline blowdowns.

> **Comment**: Removing the "distribution pipelines" terminology from the description of "pipeline venting" is an appropriate change. However, as EPA notes, because of the expansive definition of "facility" for G&B, most blowdowns associated with pipelines in that industry segment will be categorized as "facility piping" except for occasional blowdowns involving pipelines that span basins, which would be categorized as "pipeline venting." GPA requests that EPA consider whether having two separate definitions for pipeline blowdowns really serves its informational needs, especially since the two categories are rendered meaningless within G&B (and therefore, the two categories cannot be equated between processing and G&B). If EPA can obtain the information it requires with only one category for all pipeline blowdowns, then it should do so.

Proposed Change: EPA is proposing to allow and clarify use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown.

> **Comment**: GPA supports this change, but we also request that the language "best available information" be applied to all blowdowns. Operators do not always have a temperature or pressure gauge at the blowdown source, nor is it reasonable to expect operators to install such gauges upon a blowdown. It is also not appropriate to request an "engineering estimate" for a simple matter of determining a reasonable estimate of the gas temperature and pressure. "Best available information" is a broad term that requires operators to use their best data, which is an appropriate standard for this requirement.
>
> **Suggested text**:
>
> *98.233(i)(2)(i)*
> *Ta = Temperature at actual conditions in the unique physical volume (°F)~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the temperature~~.*
>
> *Pa = Absolute pressure at actual conditions in the unique physical volume (psia)~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure~~.*

Ta,p = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p"~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the temperature~~.

Pa,b,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p~~". For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the beginning of the blowdown~~.

Pa,e,p = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases~~. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates~~ based on best available information ~~may be used to determine the pressure at the end of the blowdown~~.

H. Storage Tanks

Proposed Change: EPA is proposing to require reporting of the number of controlled tanks with open or unseated thief hatches within the reporting year.

Comment: This requirement should be removed. Tracking and reporting open/unseated thief hatches is not currently required for many older tanks that are not subject to NSPS OOOO/OOOOa. Adding this requirement would greatly expand the number of tanks and facilities that would, in effect, need to comply with the OOOO/OOOOa leak tracking provisions and would create a significant additional burden on reporters. Additionally, for tanks that are subject to OOOO/OOOOa, this data element would be duplicative of the requirements of that rule, and as such, this data element would unnecessarily increase the burden of reporting by requiring the same information in multiple federal reports.

Suggested text: ~~*98.236(j)(1)(x)(D) The number of atmospheric tanks in paragraph (j)(1)(x)(C) of this section that had an open or unseated thief hatch at some point during the year while the tank was also routing emissions to a vapor recovery system and/or a flare.*~~

Proposed Change: EPA is proposing several changes that are likely to result in the double-counting of emissions through open or unseated thief hatches. EPA is also proposing that tank thief hatch emissions be quantified and reported. EPA claims this adds no reporter burden.

Comment: EPA must revise its proposal to eliminate the potential for double counting of tank thief hatch emissions. As proposed, these emissions may be counted under tanks, equipment leak population counts, and equipment leak surveys. As explained below, tank thief hatch emissions should be accounted for under the equipment leak emission sources only. This aligns with EPA's definition of fugitive emissions in NSPS OOOOa.[25]

[25] 40 C.F.R. § 60.5430a ("Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or

To elaborate on the three areas the same emissions would be counted we have provided the following additional information:

> First, EPA states that if "a reporter sees emissions from a thief hatch or other opening on a controlled atmospheric storage tank during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the 'best available data' used to calculate emissions from that storage tank."[26] EPA says the amount emitted must be quantified and reported and then used to adjust the reported emissions from the tank.
>
> Second, for leaks by population count, EPA is proposing a population emission factor in Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities) of 0.85 scf/hour per storage vessel. The proposed emission factor of 0.85 scf/equipment was derived from data that included thief hatch emissions (as noted in S-5, of the Supplementary Information for Methane Emissions from Gathering Compressor Station in U.S., Zimmerle et al., upon which the proposed emission factors were based). If this factor is finalized, then thief hatch emissions will already be accounted for under equipment leaks by population count.
>
> Third, for equipment leak surveys, in Tables W-1E (Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting) and W-2A (Default Total Hydrocarbon Leaker Emission Factors for Onshore Natural Gas Processing), EPA includes a component type labeled "Other." A leak from a tank thief hatch is generally accounted for under this "Other" category.

Emissions from an open or unseated thief hatch are difficult to quantify. Additionally, collecting and rolling up this kind of "exception data" is very burdensome in a GHG reporting program. Reporters already spend a substantial amount of time collecting and verifying data on stuck dump valves. Because quantifying these emissions and collecting this data are not easy, EPA should continue to account for these emissions under the leak categories and remove requirements specifying that unseated or open thief hatches should result in an adjustment to tank emissions. EPA should also remove the requirement to report volume of gas vented through open or unseated thief hatches. Without an involved "research project" this number will likely be an approximation, and EPA will not get the quality of data it needs to "quantify the impact of open thief hatches." It would be appropriate for EPA to clarify that open or unseated thief hatches detected while conducting a leak survey should be categorized as "Other."

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other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.").

[26] 87 Fed. Reg. at 36,968**.**

We agree that it may not be appropriate to assume 100% recovery or control of emissions from tanks that have a vapor recovery unit ("VRU") or are routed to flare. Most permit applications will include a capture/control percentage for VRUs or flares, and we propose adding language to clarify that permitted capture/control percentages should be considered an "engineering estimate based on best available data."

Finally, in section 10.2 of the "Assessment of Burden" document, EPA claims that these "clarifying edits" to 98.233(j)(4) and (5) related to open thief hatches for atmospheric storage tanks impose no additional burden on reporters. As described above, this is an incorrect assumption.

Suggested text:

98.233(j)(4)(i) Using engineering estimates based on best available data, which includes permitted capture/control percentages, determine the portion of the total emissions estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (e.g., when the vapor recovery system is not operating ~~a thief hatch is open or not properly seated)~~ when calculating emissions recovered.

98.233(j)(5)(i)(A) If unrecovered emissions from the storage tank are calculated in accordance with paragraph (j)(4) of this section, then determine the volume of the unrecovered emissions routed to flares based on best available data. If no emissions from the storage tank are routed to vapor recovery, then use the storage tank emissions volume as determined in paragraphs (j)(1) through (3) of this section, except that you must also adjust this total volume of emissions downward by the estimated portion of the total volume that is not routed to the flare (e.g., when the flare is bypassed ~~or when a thief hatch is open or not properly seated~~). Estimate the volume of the emissions not routed to flares based on best available data, which includes permitted capture/control percentages.

~~*98.236(j)(1)(xiii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(D) of this section, the total volume of gas vented through open or unseated thief hatches, in scf, during periods while the tanks were also routing emissions to vapor recovery systems and/or flares.*~~

Proposed Change: EPA is proposing to add the reporting element of flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2/CH_4 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks).

Comment: As proposed, this addition would create a significant additional burden on reporters over the current requirement to report the minimum and maximum CO_2 and CH_4 without providing EPA useful additional information. Calculating flow-weighted averages is time consuming and can be difficult to implement accurately in database software systems that are utilized by many reporters due to the way that multiple tables and data types often need to be cross referenced and brought together to calculate a flow-weighted average. GPA proposes that EPA instead modify this requirement to report to a straight average, rather than a flow-weighted average in order to reduce the complexity of complying with this requirement but still incorporates stream specific data.

Additionally, GPA notes that as currently written the text describing the calculation of the flow-weighted average could be interpreted to use the tank liquid throughputs in the calculation of that average, rather than the total flash gas volume. GPA therefore suggests the changes below to clarify that the average should be calculated based on the volume of flash gas produced rather than the liquid throughput of the tanks.

Suggested text:

98.236(j)(1)(vii) The ~~flow-weighted~~ average concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank ~~times the throughput for that storage tank~~, divided by the sum of all flash gas emissions ~~throughputs~~ from storage tanks) (''X_{CO2}'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

98.236(j)(1)(viii) The ~~flow-weighted~~ average concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank ~~times the throughput for that storage tank~~, divided by the sum of all flash gas emissions ~~throughputs~~ from storage tanks) (''X_{CH4}'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

I. Flare Stacks

Comment: As articulated further in the comments below, EPA should move away from dissecting flare emissions source-by-source and thereby introducing enormous complexity in data collection, calculation, reporting and the rule text itself. As a general matter, most facilities do not have meters on every individual source that can be routed to a flare and determining exact volumes or compositions for any individual source is often a rough estimate at best. EPA seems to be on an investigatory quest to understand the nature of flare emissions at a fine grain, and even if it was possible to do so with data routinely available at facilities (which we argue, it is not), imposing the detailed and prescriptive requirements to collect this information in an annual reporting program applicable to the vast majority of flares in oil and gas is beyond burdensome and is wholly unnecessary to determine greenhouse gas emissions from flares.

Proposed Change: EPA is proposing to require the flow-weighted annual average mole fraction of CH_4 over all streams from a particular emission source type that are used in equation W–19 to calculate the reported flared CH_4 emissions from that emission source type (and used in equation W–20 to calculate CO_2 emissions). [98.233(n)(5)]

Comment: The changes EPA is proposing are unnecessarily prescriptive and will not result in the most accurate emission calculations. Depending on how a site is configured, it can be very difficult, if not impossible, to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from individual sources to a flare is not usually metered, especially in cases where comingled flow is metered at the flare header.

Reporters should be allowed to report composition based on best available data, including but not limited to comingled waste gas stream samples, comingled waste gas stream continuous analyzers, engineering estimates, and flow-weighted annual average mole fractions. These methods would provide as valuable information for characterizing flare stack emissions as flow-weighted annual average mole fractions would and are much less burdensome for reporters. Other compliance programs involve periodic (e.g., monthly) sampling of the gas sent to flares, yet the proposed rule would not allow for the use of such data. The proposed rule should therefore be revised to align its requirements with other, similar programs.

Suggested text:

98.233(n)(2)(ii) For onshore natural gas processing, ~~when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid for all streams.~~ use best available data.

98.233(n)(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section~~. Emissions may be calculated per stream routed to the flare and then summed over all streams per emissions source type. Alternatively, you may sum the total volume of all streams from a particular emission source type, determine the flow-weighted average CO_2 and hydrocarbon concentrations over all streams per source type, and then perform a single calculation using Equation W-19 and a single calculation using Equation W-20 to calculate the total CH_4 and CO_2 emissions per source type.~~

Eq. W-19, Eq. W-20 X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. ~~Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.~~

Eq. W-19, Eq. W-20 X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. ~~Use a flow- weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.~~

98.236(n)(1)(ix) ~~Flow-weighted average mole~~ Mole fraction of CH_4 in the feed gas from miscellaneous flared sources to the flare ("XCH_4" in Equation W-19 of this subpart).

98.236(n)(1)(x) ~~Flow-weighted average mole~~ Mole fraction of CO_2 in the feed gas from miscellaneous flared sources to the flare ("XCO_2" in Equation W-20 of this subpart).

Proposed Change: For G&B and Processing, EPA is proposing to require an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations [98.236(n)(1)(v)].

Comment: This element of EPA's proposed rule would not be reasonable for reporters and would not have any impact on the amount of greenhouse gas emissions reported. Requiring reporters to estimate the volume of gas flared from each emission source type, or from each facility in the case of shared flares, may result in flare volumes being inaccurately attributed to each emission source type or facility. Depending on how a site or gathering system is configured, it can be very difficult to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from all sources is not necessarily metered, especially in cases where comingled flow is metered at the flare header. This also applies in cases where a flare is shared by multiple facilities. Our operators note that it can take multiple months, multiple staff, and essentially a research project to understand certain flaring events. Without expending significant time and effort to research the root sources of all flaring activity, the data reported will be at best a rough estimate and would not necessarily provide EPA with relevant information on sources of flared emissions. Additionally, flaring is often due to a pressure imbalance along the value chain; where that pressure is relieved/flared may be determined by a variety of factors, but this flared gas isn't easily classified as "obtained from other facilities" or "generated on site." This can be something of a chicken-and-egg question. Finally, flared gas may not be Subpart W sources, such as pressure relief valves on pressurized vessels.

Suggested text: *98.236(n)(1)(v)* ~~*Estimated fraction of total volume flared that was received from another facility solely for flaring (e.g., gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).*~~

Proposed Change: Annual reporting of information related to flare equipment.

Comment: EPA should not request data that does not directly relate to calculating and verifying GHG emissions. EPA needs to have clear purpose for how any collected data will be used to validate GHG emissions. Broad information requests are not appropriate for this annual reporting rule. These new requirements should therefore be eliminated. If EPA proceeds with this unnecessary data collection, then EPA must add an option of "Other."

Suggested text:

~~*98.236(n)(2)(ii) Indicate each emission source type that routed emissions to the flare stack during the reporting year (i.e., dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, well testing venting and flaring, associated gas venting and flaring, miscellaneous flared sources).*~~

~~*98.236(n)(2)(iv) Indicate the type of flare (i.e., open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).*~~

~~*98.236(n)(2)(v) Indicate the type of flare assist (i.e., unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).*~~

~~*98.236(n)(2)(vi) Indicate whether the flare has a continuous pilot or autoigniter.*~~

~~*98.236(n)(2)(vii) If the flare has a continuous pilot, indicate whether the presence of flame is continuously monitored.*~~

> *~~98.236(n)(2)(viii) If the flare has a continuous pilot and the presence of a flame is not continuously monitored, indicate how periods when the pilot is not lit are identified (i.e., assumed pilot is always lit, assumed pilot was unlit for a fixed number of hours or fraction of operating hours, visual observations of flare flame, other (specify)).~~*

Proposed Change: EPA is requesting that the fraction of gas sent to an unlit flare be reported twice for each flare – once for the source-level reporting, and then again for the flare event reporting.

> **Comment**: EPA should eliminate duplicative reporting requirements. These numbers will almost certainly be the same, as it will be extremely difficult for reporters to calculate the exact proportion of gas that is flowing to a flare from each source in any period when a flare is unlit and arrive at unique fractions for the individual sources versus the overall volume.
>
> **Suggested text**:
>
> For each flare stack used to control miscellaneous flared sources:
> *~~98.236(n)(1)(vii) Fraction of the feed gas sent to an un-lit flare ("Zu" in Equation W-19 of this subpart).~~*
>
> For all flare stacks:
> *98.236(n)(2)(ix) ~~Estimated fraction of the total volume routed to the flare when it was not lit.~~*

RFC: EPA requests comment on the types of sources that may be generating large emissions from flares and whether other reporting elements could be specified that would better achieve EPA's objective of clearly characterizing the sources of flared emissions from facilities involved in Production, G&B, and Processing. For example, one potential additional reporting element could be a requirement to describe the primary source of miscellaneous flared emissions for any flare that reports CO_2 emissions greater than an amount that would be determined if such a reporting requirement were finalized.

> **Comment**: As noted in our previous comment, EPA should not proceed down this path. Parsing all flare emissions into their root sources would be an enormous burden to reporters. Depending on how a site or gathering system is configured, it can be very difficult to determine specific flow volumes from each source being controlled by a flare, particularly for miscellaneous sources. Flow from independent sources is not necessarily metered, especially in cases where comingled flow is metered at the flare header. This also applies in cases where a flare is shared by multiple facilities. It can take multiple months, multiple staff, and essentially a research project to understand certain flaring events. Without expending significant time and effort to research the root sources of all flaring activity, the data reported will be a rough estimate at best and would not necessarily provide EPA with relevant information on sources of flared emissions. The intent of the GHGRP is to inform future rulemaking, and it is very unlikely that any trends to inform rulemaking could be derived from such reporting; even if there are common emission *sources*, the *causes* of such emissions are likely to be widely variable. If EPA has a desire to better understand flaring sources and root causes, then it should undertake appropriate research projects or data requests outside of this annual reporting program.

RFC: For flared sources, EPA requests comment on whether proposed changes to describe the applicable procedures for calculating flared emissions for each source type separately rather than trying to generally describe a single set of consolidated procedures makes the rule easier for reporters to understand.

> **Comment**: Per our previous comments, we do not support reporting requirements to parse out flare emission data, and the procedures for calculating flare emissions are overly prescriptive.

J. Compressors

Proposed Change: EPA is proposing to remove the requirement to measure in the not-operating-depressurized mode every three years, and EPA is proposing to add new mode-source combinations.

> **Comment**: It is possible that mode-source combination measurements may occasionally not exist, especially if a reporter calculates emission factors at the facility level. EPA should include a provision for using the last valid reporter emission factor in that circumstance.
>
> **Suggested text**:
>
> *98.233(o)(6)(iii)…*
> *Eq. W-23*
> *EFs,m = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.* *If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.*
>
> *98.233(p)(6)(iii)…*
> *Eq. W-28*
> *EFs,m = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.* *If the mode-source combination was not measured in the current reporting year and the preceding two reporting years, use the last valid reporter emission factor at the facility, or use a company-wide factor.*

K. Fugitive Leak Surveys and Equipment Leaks by Population Count

Comment: The required (and allowable) leak measurement methods are extremely difficult to discern in the rule text (98.233(j)(1) and all its cross-references). EPA should include a table in the rule to show which methods are required and/or allowable for each industry segment.

Proposed Change: EPA is proposing many emissions factor changes in the table to Subpart W with inconsistent levels of precision.

> **Comment**: Rounding has been applied inconsistently to the emission factors. For example, in Table W-1E, the leaker emission factor for valves (if surveyed using any of the methods in § 98.234(a)(1), (3), or (5)) is listed as 16 scf/hr/component. Based on the technical support document, this factor should be 15.6 scf/hr/device. There are emission factors at this level of

precision within the same table; for example, 7.9 scf/hour/component is used for connector (other). EPA should maintain consistency on decimal precision of emission factors, especially within the same table, unless the underlying data truly supports different levels of precision.

Proposed Change: EPA is proposing to separate leaker emission factors based on the survey technique: (1) Method 21 > 10,000 pm (2) Method 21 > 500 ppm and (3) OGI/IR/Acoustic.

Comment: GPA finds many of EPA's conclusions regarding the addition of leaker emission factors for survey methods other than Method 21 troubling. First, EPA chose to ignore results from two of the four recent studies for equipment leak emissions based on a weak rationale. EPA disregarded the 2011 Fort Worth Study primarily because it was geographically limited and utilized the Bacharach Hi-Flow Sampler. EPA also ignored the 2013 Allen Study because it utilized the Bacharach Hi-Flow Sampler. Geographic constraints should have no bearing on the validity of data, and the Bacharach Hi-Flow Sampler is widely used for measurement of methane emissions. There is no known rationale for assuming the Bacharach Hi-Flow Sampler results are invalid. The equipment was not discontinued by the manufacturer due to issues in its performance, but because it was no longer profitable for them to manufacturer. As EPA notes in the Technical Support Document, Bacharach is the sole manufacturer of a commercial high flow sampler. Furthermore, EPA was comfortable in using the 2020 Zimmerle Study results even though the study utilized a "redesigned" high-flow sampler fabricated with Bacharach parts by Colorado State University and SLR Consulting that has not undergone extensive testing to validate its accuracy. It makes no sense to disregard one study for use of a commercial high-flow sampler, but use a study based on a piece of equipment designed as part of collegiate research. In doing so, EPA appears to be cherry-picking scientific studies to justify revision of emission factors.

EPA also states that "these studies showed that OGI finds fewer yet larger leaks than EPA's Method 21. Therefore, the application of the same leaker emission factor to leaking components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in Subpart W, underestimates the emissions from leakers detected with OGI.[27]" GPA disagrees with this conclusion, as the only study to compare OGI with Method 21 was the 2011 Forth Worth Study, which has been disregarded. Furthermore, the 2020 Zimmerle study focused on OGI camera operator bias and not technological capabilities. EPA is also ignoring years of technical support justification for the use of OGI in lieu of Method 21 at 10,000 ppm that has been used in promulgating NSPS OOOOa and other Alternative Work Practices, including in the recently proposed OOOOb/c, where EPA states, "our analysis shows that the proposed standards, which use OGI, achieve equivalent reduction of VOC and methane emissions as the current standards, which are based on EPA Method 21, but at a lower cost."[28] Absent any new comprehensive studies comparing technological capabilities of OGI and Method 21 simultaneously at facilities, GPA believes that the justification of revised leaker emission factors is flawed. At minimum, based on previous technical support documentation, the leaker emission factors for OGI should be the same as Method 21 at 10,000 ppm.

EPA should also consider how to incorporate emerging technology that supports quantification of leaks detected by imaging.

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[27] Technical Support Document at 35 ("TSD"); *see also* 87 Fed. Reg. at 36,976**.**

[28] 86 Fed. Reg. 63,110, 63,182 (Nov. 15, 2021).

Proposed Change: For Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, and Underground Natural Gas Storage, EPA is proposing new leaker emission factors for OGI that are 4.1 times higher than the current emission factors (Tables W-2A, W-3A, W-4A).

> **Comment**: These new emission factors are not based on actual study data for processing, transmission, or underground storage. EPA calculated ratios between the current and proposed emission factors for Production and G&B (Table W-1E). The average of these ratios (4.1) was multiplied by the current processing/transmission/underground storage emission factors to arrive at the proposed emission factors. This is inappropriate. EPA did not present information to support changing the leaker emission factors for processing, transmission, or underground storage. EPA did not reference any information to indicate that the current processing, transmission, and underground storage emission factors are not representative of actual emissions. EPA did not reference any information to support that it is appropriate to apply the magnitude of change between the current versus proposed emission factors for production and G&B to the emission factors for processing, transmission, and underground storage. If EPA can justify applying production and G&B studies to processing, transmission, and underground storage, then EPA should instead update Tables W-2A, W-3A, and W-4A to have the *same* OGI leaker emission factors as Table W-1E.

Proposed Change: EPA is proposing to change emission factors for gathering pipelines in Table W-1A based on the Lamb *et al* (2015) study of distribution pipelines. In particular, the protected steel emission factor is proposed to nearly double from 0.47 to 0.91 scf/hr/mile.

> **Comment**: For gathering pipelines, proposed emission factors are based on using the "Average Methane Leak Rate" from the Lamb Study in place of the GRI/EPA Study. We think EPA made two incorrect judgements when assessing the data. First, there is a significant increase in the mean leak rate due to only a few measured leaks. The three largest leaks measured in the Lamb Study (unprotected steel main, protected steel main, and cast iron main leaks) accounted for 50% of the total leak rate, whereas 90% of the measured leaks were less than approximately 3 scf/hr. The three largest leaks are by far outliers, and significantly increase the average emission rates for the respective material. As an example, removal of the large protected steel leak reduces the average leak rate and emission factor by ~60%.
>
> Second, EPA only used leak data from distribution mains in the Lamb Study and excluded leak data from services, "[T]he emission factors for gathering pipelines by pipeline material are based on the leak rates for distribution mains by pipeline material."[29] GPA does not support separating mains and services when identifying emission factors based on pipeline material. Gathering pipelines are not segregated like distribution pipelines and do not carry main or service designations. As such, it's not appropriate to represent gathering pipelines with only a portion of data collected on distribution pipelines from the Lamb Study. All leak measurement data for each pipeline material should be considered given the pipeline material is the corresponding factor when applying the results of the study on distribution pipelines to develop emission factors for gathering pipelines. Additionally, the Lamb Study notes, "it was not always possible to clearly define a main versus a service leak when the leak occurred at the junction between main and service." The uncertainty distinguishing between pipeline mains and services provides more support to analyze the leak measurements from pipeline mains and services

[29] TSD at 61.

together. When data from mains and services are assessed together, the average leak rate for protected steel drops ~23%.

Further, EPA should consider the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") leak detection and monitoring requirements for gathering and boosting. There should be an opportunity to align data on leaks as an alternative to using an emission factor. This would also align with the directive in the Inflation Reduction Act to report emissions based on empirical data, where available.

Proposed Change: Table W-1a is being revised to list equipment leak emission factors per major equipment type, rather than per component. This change impacts the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments. EPA is implementing this change to eliminate an unnecessary step where major equipment types are converted to component counts, which are in turn used with per component emission factors to calculate emissions. EPA seeks comment on the approach of providing population count emission factors by major equipment.

Comment: Although this revision will eliminate an unnecessary calculation step for many reporters, it also eliminates the option to use actual component counts per facility to calculate equipment leak emissions. 40 C.F.R. § 98.233(r)(2) currently allows both "Component Count Method 1" – counting major equipment; and "Component Count Method 2" – counting individual components. The option to use actual individual component counts to calculate emissions should be retained as it will provide more accurate emission estimates compared to using major equipment counts. Table W-1a should include both emission factors per major equipment type and per component count to allow for either option to continue to be used.

RFC: "Under this proposed amendment, reporters would still have to meet the subpart W requirement to conduct at least one complete survey of all applicable equipment at the facility per year, so if there were components listed in 40 CFR 98.232(d)(7) not included in any NSPS OOOOb or 40 CFR part 62-required surveys conducted during the year (e.g., connectors that are monitored only once every 4 years), reporters subject to NSPS OOOOb or 40 CFR part 62 would need to either add those components to one of their required surveys, making that a complete survey for purposes of subpart W, or conduct a separate complete survey for purposes of subpart W. We expect that reporters with onshore natural gas processing plants implementing traditional leak detection and repair programs are already making similar decisions regarding how to meet the requirement to conduct a complete survey for subpart W, and our intention with this proposed amendment is not to change those decisions. Rather, this amendment would specify that surveys conducted pursuant to NSPS OOOOb or 40 CFR part 62 that do not include all component types listed in 40 CFR 98.232(d)(7) would be used for calculating emissions along with each complete survey." "We request comment on the proposed amendments to subpart W for onshore natural gas processing facilities subject to the equipment leak provisions of NSPS OOOOb or 40 CFR part 62, as well as whether there are other provisions or reporting requirements for these facilities that we should consider."[30]

[30] 87 Fed. Reg. at 36,978-79.

Comment: EPA should not mandate that data from so-called “incomplete” surveys be incorporated into the calculations. Doing so increases the complexity of the leak calculations, since some components will have different leak times in equation W-30.

L. Combustion Equipment

Proposed Change: Some Petroleum and Natural Gas industry segments calculate and report fuel combustion emissions under Subpart C (which is proposed to reference Subpart W emission factors for certain sources). Other Petroleum and Natural Gas industry segments calculate and report emissions under Subpart W, except for some equipment for which emissions are calculated under Subpart C (which is proposed to reference Subpart W emission factors for certain sources) but are still reported under Subpart W.

Comment: The elaborate structure dividing reporting requirements for similar type sources and processes among Subparts C and W has long been a source of confusion, administrative difficulty, and cost for affected facilities. For reporting consistency and to improve transparency, GPA requests that EPA consolidate combustion source calculation and reporting (40 C.F.R. §§ 98.233(z) and 98.236(z)) for all Petroleum and Natural Gas Systems segments under Subpart C – General Stationary Fuel Combustion Sources.

As currently structured, Subpart W requires the Production segment, Gathering & Boosting segment, and the Distribution segment to calculate and report their combustion emissions under Subpart W. All other segments of the industry calculate and report combustion emissions under Subpart C (40 C.F.R. § 98.232(k)). This includes the majority of the segments in the industry: onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (“LNG”) storage, LNG import and export equipment, onshore natural gas transmission pipelines.

It has never been clear why EPA would treat the Production, Gathering & Boosting, and Distribution segments differently than the other industry segments in this regard—the source of the emissions, combustion, is the same. GPA has commented to EPA in previous rulemaking proceedings addressing Subpart W that the Agency’s unusual approach with respect to these facilities, inconsistently piecing together combustion-related emission reporting requirements across various subparts, lacks a clear rationale or precedent.[31] Indeed, because Subpart C is proposed to reference Subpart W emission factors for certain sources, and Subpart W will continue to reference Subpart C calculation methods for certain sources, the utility of housing combustion emission requirements under two different subparts will not only remain unclear and confusing but become more so.

Further this complex system with its many cross-references creates multiple and unnecessary opportunities for mistakes in the regulatory text itself, future agency guidance, and for companies attempting to implement the rule. As noted in the Federal Plain Language

[31] *See* Gas Processors Association, Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule (Docket EPA-HQ-OAR-2014-0831) at 24-26, 34 (Feb. 24, 2015).

Guidelines, "There are several ways to deal with cross-references. The best is to organize your material so you can ***eliminate the need for cross-references*.**"[32]

These issues are especially complex for companies that must report under the conflicting reporting regimes for different facility types that are treated differently under Subpart C and Subpart W, and the costs of maintaining separate systems for such facilities are not insignificant.

As EPA has previously explained, the purpose of Subpart W was to require the calculation and reporting of vented, fugitive, and flare combustion emissions, while "stationary combustion emissions are included in Subpart C."[33] Without providing a straightforward rationale for failing to adhere to that basic practice by including some combustion emissions in Subpart W, EPA has acted arbitrarily. An agency's basic obligation under the law is to assess the relevant facts and provide a reasoned rationale for its choice of action. As the D.C. Circuit has explained, agencies must "consider[] the relevant factors and articulate[] a rational connection between the facts and its choices."[34] Although it is permissible for an agency to make a decision that contradicts an earlier approach to a similar situation, when so doing, it must "supply a reasoned analysis for the change."[35] On the other hand, when an agency treats similarly situated parties differently, taking conflicting approaches based on the same or similar data, "[s]uch inconsistent treatment is the hallmark of arbitrary agency action," and requires further explanation from EPA.[36]

Here, the approach EPA has taken with respect to Production, Gathering & Boosting, and Distribution differs from and conflicts with the approach taken for other segments in the natural gas industry. The unusual division of reporting for these segments also differs from EPA's approach under other subparts of the GHGRP. EPA has supplied no clear rationale, and none is obvious.

Under these circumstances, the appropriate course of action is for EPA to move all combustion reporting under Subpart C. That would also allow EPA to streamline data aggregation and reporting for the annual Inventory of US GHG Emissions and Sinks and for other consumers of the reported data. Moving all combustion requirements to Subpart C could be accomplished by "lifting and shifting" regulatory text related to calculations, monitoring, and reporting from Subpart W to Subpart C. GPA is not proposing any changes to existing requirements related to combustion or sector threshold determinations.

Proposed Change: EPA is proposing three methane emission factors in Table W-9 (or three combustion efficiencies in Equation W-29) from reciprocating engines that drive compressors: two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn.

Comment: GPA does not oppose the proposed emission factors/combustion efficiencies. However, the proposal does not provide an opportunity for reporters to reduce emissions from this source and account for those reductions in their reports. The combustion calculations should allow reporters to use the emission factors in Table W-9 *or* use OEM (original equipment

[32] Federal Plain Language Guidelines at 83 (emphasis in original) (May 2011)
[33] 69 Fed. Reg. 18,576, 18,611, 18,614 (Apr. 12, 2010).
[34] *Nat. Res. Def. Council, Inc. v. EPA*, 194 F.3d 130, 136 (D.C. Cir. 1999).
[35] *Jicarilla Apache Nation v. DOI*, 613 F.3d 1112, 1119 (D.C. Cir. 2010).
[36] *Catawba Cnty., NC v. EPA*, 571 F.3d 20, 51 (D.C. Cir. 2009).

manufacturer) specific emission factors *or* use stack test data *or* apply a percent reduction to the Table W-9emission factors based on other data. Operators, engine manufacturers, and engine catalyst manufacturers are rapidly working to develop technologies to minimize methane slip. Allowing use of OEM specific factors, or stack test data, or a control percentage applied to the emissions incentivizes reporters to reduce methane slip, and by extension incentivizes engine and catalyst manufacturers to develop low methane emissions technology for both new and existing engines (with, for example, upgrade kits). EPA must not stifle innovations that are currently under development to reduce methane emitted to the atmosphere. If reporters cannot account for improvements in engine methane emissions, then improvements are much, much less likely to happen. Because this is an area of developing innovation, EPA should allow reporters to use the calculation method that is most representative of emissions, whether that be Table W-9 factors, OEM factors, stack test data, or control percentages applied to Table W-9 factors. With the confluence of possible SEC reporting, methane fees, ESG reporting, responsibly sourced gas certifications, and other driving forces for methane emission reductions, EPA must allow reporters to accurately reflect their emissions using a variety of means to calculate emissions. Especially for significant sources of methane emissions, like engine slip, the time for allowing flexibility in calculations is now, not a future rulemaking. The request also aligns with the directives in the Inflation Reduction Act to pursue reported emissions based on empirical data.

Proposed Change: EPA is clarifying that emissions may be calculated in 40 C.F.R. § 98.233(z)(3)(ii) for groups of combustion units. However, if any of the combustion units downstream of this shared measurement point are natural gas-driven compressor drivers, the volumes of fuel for those units would have to be separated from the total before emissions are calculated to account for the differences in combustion efficiency.

Comment: EPA should allow grouping of natural gas-driven compressor driver engines if they are of the same class. First, at a G&B station, most fuel combustion equipment are compressor drivers, with possibly one or two small heaters. Second, it takes considerable work to apportion fuel use to each piece of equipment. One must use actual station fuel use, individual equipment heat rate, and individual equipment actual run hours to properly apportion fuel use, and the calculations accordingly must be performed using a mix of station-wide operating data (fuel use), equipment properties (heat rate), and equipment operating data (run hours). This is difficult to automate. However, if a station consists of, for example, three 4 stroke-rich burn engines, and a heater less than 5 MMbtu/hr, the reporter should be able to simply use the station fuel use and the 4-stroke rich-burn methane emission factor and combustion efficiency. This would dramatically reduce burden and provide the same emissions data.

Proposed Change: EPA is proposing new methane emission factors for two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn reciprocating engines. However, throughout the preamble and proposed rule text, EPA uses the inaccurate and broad terminology of "compressor drivers" to refer to these engines.

Comment: In addition to engines, midstream operators commonly use <u>turbines</u> as compressor drivers. EPA is not proposing new methane emission factors for turbines. Therefore, EPA must replace the term "compressor drivers" with "compressor driver-engines" (or something similar) throughout the preamble and rule text, including in both Subparts C and W, to clarify that turbines are not included.

Proposed Change: In Subpart C, for reporters aggregating units, EPA is proposing that for *each* unit in the group, an estimate of the total annual heat input (expressed as a decimal fraction) must be reported, and this estimate should be based on the *actual* heat input of the unit compared to the *actual* heat input of all units in the group.

> **Comment**: EPA claims this is "not expected to significantly increase burden for reporters" but if the fraction must be based on **actual** heat inputs, then this requirement significantly increases burden and essentially negates the time efficiencies gained by reporting the aggregated group, especially for reporters who use the common pipe method of aggregation. By proposing that actual heat inputs must be used, EPA would essentially require that heat inputs be calculated for each piece of equipment each year, which would eliminate the benefits of reporting an aggregate group where heat input is calculated only once for whole group of equipment. This data element should be eliminated, since the maximum rated heat input capacity of each unit in the aggregated group should provide enough information for EPA to reasonably approximate emissions per individual pieces of equipment for bulk analysis purposes. At the very least, EPA should not mandate that this be based on *actual* heat input per equipment. If EPA does not make either change, then EPA must reflect the significant increase in burden in the *Assessment of Burden Impact for Proposed Revisions for the Greenhouse Gas Reporting Rule*. This would be approximated by multiplying the effort expended by reporters using an aggregation method by the number of pieces of equipment in the aggregated group. For GPA members using the common pipe method, for example, a ten-fold increase in burden (or more) would be a reasonable assumption of burden increase, especially since EPA further specifies that, "Estimates of the actual heat inputs may be based on company records."[37] This could be interpreted to mean that all available data must be used to develop the actual heat inputs, which further emphasizes the burden of this new requirement.
>
> **Suggested text**: [preferred] 98.36(c)(1)(ii) *For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, and maximum rated heat input capacity~~, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the actual heat input for that unit (all fuels) by the sum of the actual heat input for all units (all fuels), including units less than 10 mmBtu/hr. Estimates of the actual heat inputs may be based on company records~~. If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.*
>
> **Suggested text** [alternative] 98.36(c)(1)(ii) *For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, maximum rated heat input capacity, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the ~~actual~~ heat input for that unit (all fuels) by the sum of the ~~actual~~ heat input for all units (all fuels), including units less than 10 mmBtu/hr. ~~Estimates of the actual heat inputs may be based on company records.~~ If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.*

[37] 87 Fed. Reg. at 37,042.

M. Other Large Releases

Proposed Change: Calculate and report GHG emissions from other large release events that release at least 250 mtCO_2e per event.

> **Comment**: A quantifiable time element must be added to the emissions threshold of "other large release events." We propose that 250 mt of CO_2e released in any 24-hour period be used as the threshold for the definition of "other large release events." This will align with other common state and federal reporting thresholds, which include quantification of emissions over a 24-hour period. This will reduce burden by allowing reporters to align GHG emissions quantifications with other requirements when determining whether release event thresholds are met. A 24-hour quantifiable time element will also ensure that events that are quantified and reported are truly "large" release events, rather than low-level leaks over longer periods of time that would be addressed via the fugitive leak quantification requirements of Subpart W.
>
> **Suggested text**: *98.233(y) Other large release events. Calculate CO_2 and CH_4 emissions from other release events for each release that emits GHG in excess of 250 metric tons of CO_2e in a 24-hour period as specified in paragraphs (y)(1) through (4) of this section.*

Proposed Change: Calculate and report GHG emissions from other large release events that release at least 250 mtCO_2e per event.

> **Comment**: To reduce reporter burden, EPA should strive to align this requirement with other federal reporting thresholds. We suggest the large release event threshold should be 3 MMscf to align with Pipeline and Hazardous Materials Safety Administration reporting requirements. Doing so would help reporters align within their company on reporting and data collection procedures.

Proposed Change: If a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in Subpart W by 250 mtCO_2e or more, EPA is proposing that such releases would be included in the definition of "other large release events" and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release events.

> **Comment**: EPA must clearly define the emission sources to be reported as (or excluded from) the "other large release events" emission source category. It would be unworkable and confusing for reporters if EPA were to "mix" reporting requirements for certain sources where sometimes emissions are characterized as "other large release events" and sometimes not. The articulated categories suggested below should capture the majority of large release events in a manner that would accurately reflect such emissions.
>
> *98.238 Definitions. Other large release event means an unplanned, unexpected, and uncontrolled release to the atmosphere of gas, liquids, or mixture thereof~~,~~ from ~~wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 to appropriately estimate these emissions. Other large release events include, but are not limited to,~~ well blowouts, well releases, pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. ~~Other large release events also include failure of equipment or equipment components such that~~*

~~a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233 by the threshold in § 98.233(y).~~

Proposed Change: For "other large release events," EPA proposes to collect data elements that are extraneous to the information EPA needs to assess and compile GHG emissions. This information includes proposed reporting of the start and duration of an event, a description of the event, and volume fractions of emissions, among other things.

Comment: Such reporting is not likely to provide information of regulatory value or to inform the development or implementation of any EPA regulatory program. The significant additional burden that these requirements will impose are, therefore, not justified, and they should be removed from the rule.

Additionally, it is important to emphasize that these types of emissions are likely complicated to assess, and providing EPA with additional "raw" data is unlikely to allow the Agency to effectively validate reporting of emissions from these sorts of abnormal emission events. Regarding EPA's proposal to request reporting on "whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter," the rule should expressly recognize that "NA" must be an option because some events will be caused by sources not subject to those rules.

Suggested Text:

98.236(y) Other large release events. You must indicate whether there were any other large release events from your facility during the reporting year. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through ~~(8)~~(4) of this section.

(1) Unique release event identification number (e.g., Event 1, Event 2).

~~(2) The approximate start date, start time, and duration (in hours) of the release event.~~

~~(3) A general description of the event. Include:~~

~~(A) Identification of the equipment involved in the release.~~

~~(B)~~(2) ~~A description of how the release occurred, from one of the following categories~~ The category: fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

~~(C) A description of the technology or method used to identify the release.~~

(D) An indication of whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

~~(E) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted.~~

~~(4) The total volume of gas released during the event in standard cubic feet.~~

~~*(5) The volume fraction of CO_2 in the gas released during the event.*~~

~~*(6) The volume fraction of CH_4 in the gas released during the event.*~~

~~*(7)*~~*(3) Annual CO_2 emissions, in metric tons CO_2, from the release event.*

~~*(8)*~~*(4) Annual CH_4 emissions, in metric tons CH_4, from the release event.*

N. Other Reporting Elements

Proposed Change: EPA is proposing to add, as reporting element, the count of compressor stations within a basin to facilitate better understanding of G&B operations [98.236(aa)(10)(v)], at the request of GPA Midstream.

Comment: GPA thanks EPA for making this kind of change, as we think a change of this nature will add value when analyzing data from a G&B basin. However, recently GPA has found that limiting this count to compressor stations only does not adequately meet the intent of collecting this particular data element, which is to provide a way to "spread" the data reported across the number of facilities in the basin, so that it can be viewed and interpreted in light of a more traditional definition of "facilities." GPA therefore suggests revising the rule to require additional information, which will provide a more complete understanding of typical equipment counts at gathering and boosting assets. Please also see the next comment where this change provides additional value.

Suggested text: new definition in 98.238 Gathering and Boosting Station *means a booster compressor station, treating facility, centralized gathering facility, metering station, or dehydration facility.*

98.236(aa) (10)(v) The number of ~~compressor stations~~ gathering and booster stations in the facility.

Comment: In addition to collecting information on the number of gathering and boosting stations in a basin, GPA also encourages EPA to acquire additional information related to other key differences in the basins. For example, gathering systems that operate with low suction pressure will require more compression to move gas (sometimes twice as much compression), and this type of information may provide insight into differences in emissions between operators and/or basins.

Suggested text: *98.236(aa) (10)(vi) Average gathering and booster station inlet pressure.*

Comment: Reporting element 98.236(aa)(10)(ii)—"The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet"—is collected to assess basin throughput. However, this throughput metric only captures gas at the boundaries of a G&B basin and does not adequately capture gas movement within a basin. For example, it is not uncommon for gas to travel through multiple compressor stations in series on its way to a gas plant. However, with the current throughput definition, this gas movement is only captured once – at the gas plant. Just as understanding the number of gathering and booster stations in a basin is critical for data analysis, understanding gas flow through gathering and boosting stations as it truly moves within a basin is critical. We suggest that EPA include in this data element any gas volume that moves through a gathering and boosting station that is not otherwise captured by the existing definition.

Suggested text: *98.236 (aa)(10)(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet. This quantity should also include volume transported from one gathering and boosting station to another gathering and boosting station within the basin that is not otherwise accounted for.*

O. Purchased Energy Products

RFC: EPA is seeking comment on requiring GHGRP reporting facilities to submit summary data elements quantifying their consumption of purchased energy products and characterizing associated markets and products (e.g., regulated, or de-regulated electricity markets and renewable attributes of purchased products). Under this approach, facilities would not be required to quantify indirect emissions, and indirect emissions would not count towards GHGRP applicability.

Comment: The primary purposes of this proposed rule are to streamline implementation, make minor changes, clarify confusing provisions, and to improve the overall quality and consistency of the data reported under the GHGRP. This aspect of the proposed rule would not achieve any of those goals. It would represent an extraordinary broadening of the GHGRP. It could also result in significant double-counting of emissions. Undoubtedly, the vast majority of GHG emissions associated with power generation are already accounted for under EPA rules. That information is supplied directly by power producer, who have access to the best information available to characterize GHG emissions associated with such power. Asking power consumers to report that same information will result in unnecessary duplication of efforts and poorer quality information overall.

Further, the purpose of any information collection under section 114 of the CAA is for the development or implementation of regulatory requirements. EPA does not have authority to regulate energy consumption, so there is no appropriate purpose for collecting the information addressed in this element of the proposed rule.

This information is also very hard to track down. In most cases, facilities receive an electricity bill, similar to what you receive for your home. It does not include information on regulated or de-regulated electricity markets and renewable attributes of purchased products. For this request to work, electricity suppliers would need to provide this information in a clear manner to their customers. Right now, that is not the case, and there is presently no obligation upon those providers to do so. Operators simply do not have access to this information. EPA suggests that this information could be used to support the development of voluntary programs. Under those circumstances, EPA could consider providing for a voluntary purchased power reporting program. Such a program would require significant additional consideration and would not appropriately be included in the GHGRP

P. Burden Impacts

Comment: The overall burden of $842/year per Subpart W reporter to comply with the proposed rule changes is grossly underestimated. Per Table 3-2 of the Assessment of Burden document, EPA estimates an annual average cost per reporter for reporting and recordkeeping requirements of $412 for Subpart W. EPA estimates an annual average cost per reporter for monitoring and calculation methodology of $430 for Subpart W. At a cost $91/technical labor for Subpart W, simply reading the rule once would cost $228, which is 27% of EPA's average annual cost. The rule itself contains 101 new G&B data elements. Responding to the proposed changes will require many hours of additional work for which EPA has not appropriately accounted. GPA welcomes the opportunity to further discuss development of more realistic burden estimates with the Agency.

Comment: The method of determining respondent hours is inappropriate for G&B. For G&B, EPA attests there are 101 new data elements. The calculations multiply the respondent hours by the number of reporters, but this grossly underestimates the true level of effort because there is not one data element per reporter; the data element is repeated by the number of applicable pieces of equipment within the basin, which could be hundreds. For any new data element that is reported per equipment (i.e., more than once per report), EPA must assess how many affected pieces of equipment would have a new data element and use that number as the multiplier (not simply the number of reporters). EPA has all the data necessary to perform these calculations. If EPA assumes that a data element which may need to be reported for hundreds of pieces of equipment within a basin takes a grand total of 3 minutes per year per reporter to gather, QA/QC, and report, then EPA is completely detached from the reality of reporting under this rule.

Comment: In the Cost Spreadsheet, EPA nets out removed data elements from the cost estimate. This is inappropriate. For the initial year of reporting, any change results in work, even the exclusion of data elements. This is because reporters need to update their documentation, procedures, databases, and report mapping to remove these elements. Removed elements result in work. As such, the removal of a data element doesn't somehow negate the burden of an additional data element, especially in the first year of reporting when reporters must update procedures, documentation, calculations, databases, reporting mapping, etc.

Comment: EPA is proposing revisions to 40 C.F.R. § 98.36(c)(1) and (c)(3) to clarify that reporters may not report a combination of one design class of compressor driver engines (using one Table W-9 CH_4 emission factor) and other combustion units (e.g., using a Table C-2 CH_4 emission factor or another Table W-9 CH_4 emission factor) in the same aggregation of units or common pipe configuration. EPA claims the proposed change does not impose any new monitoring or reporting requirements and therefore has no impact on burden. This is false. At gas plants, it is not common (and is possibly never the case) to have an individual fuel meter on each piece of fuel combustion equipment. Reporters use the Subpart C aggregation/common pipe methods because that aligns with how fuel meters are set up – one meter for multiple pieces of equipment. Disallowing aggregation/common pipe between compressor driver engines and other combustion units will result in much more work, since instead of simply collecting volume and composition for a meter, reporters will have to apportion fuel use for all equipment on the meter. Reporters will have to collect fuel volume, fuel composition, heat rate for each equipment, run hours for each equipment (which is often not automated), and calculate the portion of fuel use per equipment using heat rate and run hours, and multiply that portion by the total fuel volume. While we understand that methane emission factors can't be mixed between design classes of compressor driver engines and other combustion units, EPA must at the very least properly account for the increase in burden. We estimate at least 2 hours per year per each aggregation of units/common pipe reported under Subpart C.

Comment: The time estimated per data element is too low, especially for calculated data elements. Per the Cost Spreadsheet tab "W (Data Elements)", EPA estimates 0.05 hours per data element, or 3 minutes per data element. EPA claims in the Assessment of Burden document that "There are no capital or operation and maintenance costs associated with the proposed revisions to add, revise, or remove data elements, because the proposed data elements may generally be obtained from existing company records or are readily available from existing information gathered under part 98, therefore, no additional monitoring or sampling is required" and "With the exception of new data elements required of reporters using the aggregation of units or common pipe configuration under subpart C, EPA assumed 3 minutes of technical labor to calculate each data element using readily available data and to submit the value via e-GGRT or enter the value into IVT." We do not understand how EPA can, with a straight face, assume such a tiny amount of time to gather the necessary data, calculate, QA/QC and report. GPA members anticipate spending a significant amount of time (e.g., months) gathering information, updating database calculations, updating reporting mapping, and updating QA/QC procedures just to initially set up the structure required to comply with these rules. This is far cry from EPA's estimate of a grand total of 6.84 hours of additional effort per year per G&B reporter and 3.68 hours per year per Processing reporter. At the very least, EPA needs to differentiate between data elements that are simple reporting elements (like count of pumps) versus data elements that have calculations behind them (like parsing out flare volumes and emissions data between different flared sources or calculating a flow-weighted basin average tank flash gas composition). While it *might* be appropriate to estimate *some* of the simple reporting elements at 3 minutes annually, any element involving a volume, emission, or composition calculation should be estimated at no less than 15 minutes.

Comment: EPA assumes the following changes have no significant impact on burden. These changes include new emission source measurements, calculations, and reporting requirements that must be incorporated into a reporting program. This reporting rule is prescriptive, complex, and expansive; most midstream reporters have implemented one or multiple databases to make the workload manageable. Operators also have documentation, QA/QC procedures, and other tools to ensure the data is complete and potentially auditable by a third party. As such, *any* change in measurements, calculations or how information is to be reported (even changes that are meant to simplify or clarify) will likely result in work. Operators must update documentation, redo training, change QA/QC procedures, update data collection systems, update database calculations, and update report mapping. It is incorrect to assume changes to measurements, calculations, or reporting have no significant impact on burden.

- Adding add standby-pressurized-mode to the defined modes for centrifugal compressors.
- Measurement of rod packing leaks from reciprocating compressors when found in standby-pressurized mode.
- Revise § 98.233(r)(2) to state that the gas service emission factors and default component counts in Table W-1A and Table W-1B should be used for all subject components at Onshore Petroleum and Natural Gas Gathering and Boosting facilities.

- Revise reporting elements related to flare stacks in § 98.236(e), (g), (h), (j), (k), (l), and (m) to include the data elements formerly reported in § 98.236(n).
- Clarifying edits to § 98.236(j) related to open thief hatches for atmospheric storage tanks.
- Revise the reporting elements for atmospheric tanks from "the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas" to "the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas" in § 98.236(j).
- Modify reporting requirements in § 98.236(n) to capture information only from "miscellaneous flared sources" (i.e., emission sources which are not listed separately in the reporting form or in the XML schema).

Appendix A

Table of changes GPA supports as proposed.

Sub part	Citation	Change
A	98.2(i)(1) and (2)	Clarify cessation of reporting (based on emissions calculated by GHGRP methods, and reassess of applicability uses calc methods simpler than reporting calc methods)
A	98.4(n)(1)-(4)	Clarify reporter for acquisitions/divestitures in oil and gas during the year of sale and onward
A	98.3(h)(4)	Maximum of 180 days to correct substantive errors
A	98.1(c)	Clarify definitions of owner and operator for G&B
A	98.6	Clarify dehydrator vents include still and flash
A	98.6	Clarify dehydrator vapor recovery does not include fire-box/fire tubes
A	98.6	Update dehydrator definition to remove desiccant; remove definition of "desiccant"
C	98.36(c)(1)(vi), 98.36(c)(3)(vi)	Remove the language requiring reporting of the total annual CO2 mass emissions from all fossil fuels combined if the unit also burns biomass.
W	98.238	Definition of "Routed to combustion"
W	98.238	Flare Stacks: Revising definition of *Flare Stack Emissions*
W	98.233(a)(1), 98.233(a)(6), 98.236(b)(2)	Natural gas pneumatic device venting: Clarify hours of operation means hours in service
W	98.233(c)(1), 98.236(c)(4)	Natural gas pneumatic pump venting: Clarify hours of operation means hours in service
W	98.233(c), 98.233(c)(3)	Natural gas pneumatic pump venting: Clarify emissions from pumps routed to flares, combustion, or vapor recovery systems are not reported under 98.233(c)
W	98.233(c)	Natural gas pneumatic pump venting: Natural gas driven pumps reported under 98.233(e) *Dehydrator vents* do not need to be reported under 98.233(c) *Natural gas driven pneumatic pump venting*
W	98.236(n)(1)(xi)	Flare Stacks: Clarification that flare stack CO2 emissions should exclude CO2 emissions reported under Acid Gas Removal Units.
W	98.233(i)	Blowdowns: Remove exclusion of desiccant dehydrator blowdown venting before reloading.
W	98.233(i)(2)(i) Equation W-14A Equation W-14B	Blowdowns: Allow engineering estimates based on best available data to determine temperature and pressure of emergency blowdowns for Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting
W	98.233(j)(1)(x)(A) 98.233(j)(1)(x)(B) 98.233(j)(1)(x)(C)	Tanks: Clarify/simplify reporting of the count of tanks
W	98.233(o)(1)(i)(A) 98.233(o)(1)(i)(B)	Centrifugal Compressors: Revising 98.233(o)(1)(i)(A) and (B) to reference 40 CFR 98.233(o)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements.

W	98.233(o)(10) 98.236(o)(5)	Centrifugal Compressors: Clarify that the compressor count used in Equation W-25 should be the number of centrifugal compressors with atmospheric (i.e., uncontrolled) wet seal oil degassing vents.
W	98.233(p)(1)(i)(A) 98.233(p)(1)(i)(B) 98.233(p)(1)(i)(C)	Reciprocating Compressors: Revising 98.233(p)(1)(i)(A), (B) and (C) to reference 40 CFR 98.233(p)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements.
W	98.233(p)(10) 98.236(p)(5)(B)	Reciprocating Compressors: Clarify that the compressor count used in Equation W-29D should be the number of reciprocating compressors with atmospheric (i.e., uncontrolled) rod packing emissions.
W	98.236(o)(1)(xiv) 98.236(p)(1)(xiv)	Compressors: Remove reporting requirement of whether compressor had scheduled shutdown.

Attachment B

January 18, 2023

Via e-filing on www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Attention: Docket ID Nos. EPA-HQ-OAR-2022-0875, EPA-HQ-OAR-2022-0875-0002
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Information, "Methane Emissions Reduction Program," Docket ID Nos. EPA-HQ-OAR-2022-0875, EPA-HQ-OAR-2022-0875-0002

Dear Docket Clerk,

Thank you for the opportunity for GPA Midstream Association ("GPA Midstream" or "GPA") to provide comments to the U.S. Environmental Protection Agency's ("EPA" or the "Agency") request for information, titled "Methane Emissions Reduction Program" ("MERP RFI").

GPA Midstream has served the U.S. energy industry since 1921 and has over 60 corporate members that directly employ more than 56,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids ("NGLs"), refined products, and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 396,000 jobs across the U.S. economy. GPA Midstream members gather over 77% of the natural gas and recover more than 80% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 380 natural gas processing facilities. In the 2019-2021 period, GPA Midstream members spent over $100 billion in capital improvements to serve the country's needs for reliable and affordable energy.

GPA and its members have participated in each EPA rulemaking to address greenhouse gas ("GHG") emissions from the oil and natural gas midstream industry, including the initial development of the greenhouse gas reporting program ("GHGRP") in 2009. Since that time, GPA has continued to work with EPA to improve, streamline, and clarify the requirements of 40 C.F.R. Part 98. We recently provided extensive comments on EPA's proposed rulemaking "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36,920 (June 21, 2022), Docket ID No. EPA-HQ-OAR-2019-0424.

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We hope EPA finds the enclosed information useful. GPA welcomes the opportunity to continue discussions with the Agency as it develops its revisions to the GHGRP and implements the MERP.

Respectfully submitted,

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Contents

On November 3, 2022, EPA announced the opening of a nonregulatory docket to accept public comment on new and existing programs addressed by the Inflation Reduction Act ("IRA"). EPA's Request for Information ("RFI") includes six separate dockets. These are the comments of the GPA Midstream Association ("GPA") on Docket 3: Methane Emissions Reduction Program (the "MERP RFI"). The MERP RFI addresses section 60113 of the IRA, which establishes (1) a waste emission charge on methane emitted from applicable oil and gas facilities; and (2) a $1.55 billion financial and technical assistance program to reduce methane emissions from the oil and gas sector. EPA poses specific questions regarding both of the section 60113 programs. GPA is pleased to offer these comments and hopes that they will help inform EPA's implementation of the IRA's methane reduction provisions.

1. Methane emissions from stationary combustion sources are not "waste emissions" and should not be subject to the waste emissions fee

It is crucial that, in any final rule implementing the directives in the IRA, EPA directly and explicitly exclude from the definition of methane emissions those that are not actually "waste emissions" such as any emissions resulting from the operation of equipment intended to actually perform a beneficial function—such as those that result from utilizing natural gas as fuel for engines driving compressors or generators.[1]

The text of the IRA supports this exemption. Specifically, Section 60113 makes a clear distinction between emissions that result from beneficial use and waste emissions, as it provides funding for "improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions *and waste*"[2] and for "supporting innovation in reducing methane and other greenhouse gas emissions *and waste* from petroleum and natural gas systems."[3]

A recent proposed ruled from the Bureau of Land Management further supports this distinction between beneficial use and waste emissions and even specifies explicitly that waste is associated with venting, flaring and leakage.[4] Emissions resulting from stationary combustion are fundamentally different; rather than being wasted, gas at those sources is used to fuel critical energy infrastructure. This interpretation is not precedent setting as Congress knows how to address methane emissions from beneficial uses and from waste and how to address waste emissions alone.[5] It did both of those things within section 60113, and it made clear that the methane fee provision was intended to apply to waste emissions only.

After all, the majority of combustion exhaust methane emissions are a direct result of industry being driven by EPA to reduce criteria pollutant emissions such as NOx and CO by switching combustion engines to lean-burn technologies. Methane emissions are inherent to a low-NOx/low-CO combustion process and lack any currently feasible or practical means of control. State gas capture programs such as in New Mexico [NMAC 19.15.28.8.F(3(a)] and North Dakota [NDIC Order 24665 (4)(b)] recognize this and deem gas used for combustion as beneficial use. These state gas capture programs do not count

[1] These emissions are often colloquially referred to as "methane slip." This term and "combustion exhaust methane emissions" are meant to be used interchangeably throughout these comments.
[2] IRA § 60113 (adding new Clean Air Act ("CAA") § 136(a)(3)(B) (emphasis added).
[3] *Id*. (adding new CAA § 136(a)(3)(C) (emphasis added).
[4] "Prevent the waste of gas through venting, flaring and leakage." 87 Fed. Reg. 73,588 (Nov. 30, 2022).
[5] *See, e.g.*, *Hamdan v. Rumsfeld*, 548 U.S. 557, 578 (2006).

fuel gas or fuel gas combustion products against gas capture target requirements and certainly do not deem it waste.

EPA has discretion under the statute and can address this issue through administration of the program. It should therefore make this clarifying point to ensure that combustion methane emissions are not considered "waste" and the intention behind the IRA is fulfilled.

2. Combustion exhaust methane emissions should report under Subpart C- General Stationary Fuel Combustion Sources

The IRA applies the waste charge to a "facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to *subpart W* [emphasis added]." While many sources covered by Subpart W could reasonably be deemed a waste and subject to a waste emission fee, methane emissions from combustion sources are a true outlier (because they are, in fact, not "wasted"), and so should not even be subject to reporting under Subpart W. Instead, the most appropriate way to address this issue is to revise Subpart W to redirect stationary combustion emissions to Subpart C – General Stationary Fuel Combustion Sources of the GHGRP. As described below, such action would be consistent with the intent behind section 60113 of the IRA, and it would rectify a longstanding discrepancy with Subpart W.

Subpart W was originally promulgated on November 30, 2010, with the express intent to add requirements for facilities that contain petroleum and natural gas systems to report equipment leaks and vented GHG emissions to the GHGRP. EPA later amended Subpart W on October 22, 2015, to include the addition of calculation methods and reporting requirements for GHG emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. Stationary combustion emissions are not equipment leaks or vented emissions and would be more appropriately reported under Subpart C. It would also be arbitrary and capricious for EPA to continue requiring the reporting of stationary combustion emissions under Subpart W for the onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution segments when *all* other segments of the petroleum and natural gas industry and all other industries with fuel combustion emissions report to Subpart C. GPA submitted comments to EPA to this effect in the docket for the June 21, 2022 proposed rule to the GHGRP.[6] For these reasons and the reasons stated in the GPA 2022 Subpart W Comments, EPA should revise Subpart W to move combustion sources for all industry segments to Subpart C.

If EPA is unwilling to move these emissions to Subpart C, GPA recommends that EPA make clear when administering the collection of the methane waste emissions charge that gas used for stationary combustion is a beneficial use—or that the resultant methane emissions from stationary combustion are deemed as unavoidably lost—and so are not subject to the waste emissions charge.

[6] Comments of GPA Midstream Association on The U.S. Environmental Protection Agency's Proposed Rule: "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, EPA Docket ID No. EPA-HQ-OAR-2019-0424-0192 (Oct. 6, 2022) ("GPA 2022 Subpart W Comments").

3. The historical context behind the IRA's waste emissions thresholds needs to be considered when determining how it will be implemented

A full understanding of the historical context underpinning the development of the waste emissions thresholds is crucial for ensuring that the IRA's language is properly implemented through its promulgating regulations. For example, most GHG emissions reporting to date (via GHGRP or other GHG reporting frameworks) has not adequately accounted for stationary source combustion exhaust methane emissions, and so it is unlikely these emissions were considered when establishing the waste thresholds. As such, it would be inappropriate to include these emissions when assessing a waste fee.

4. Emission factors should be considered empirical data

Emission factors are based on real-world empirical data. As such, EPA should interpret the IRA's mandate to base the methane waste charge on "empirical data" to include the use of emission factors. Relatedly, EPA should not mandate direct measurement of all sources. Direct measurement can provide granular point-in-time data, but it is also very costly and time consuming compared to using emission factors for some sources (for example, fugitive leaks) and will not necessarily yield better information on average. The time and money spent on direct measurement could instead be more effectively allocated to reducing or eliminating methane emissions.

5. Continuous monitors are not the panacea for emission reporting

EPA should consider preferring direct measurement techniques or emission factors based on *truly* direct measurement over indirect quantification technologies, and EPA should generally be cautious in preferring certain indirect measurement techniques over others. Specifically, a number of emerging "continuous monitoring" technologies coming to the marketplace imply that they can accurately measure emissions; in reality, these technologies do not directly measure emissions but rather extrapolate data to estimate a quantified emission amount. These technologies may have spatial issues (using trajectories based on meteorological data) or temporal issues (the measurement is a snapshot in time) that can result in significant uncertainty bounds (sometimes as much as 100% off when compared to direct measurement), and their accuracy is only as good as the proprietary systems correlating the detected data and emissions, many of which are still being adjusted and refined for accuracy.

Monitoring systems can indeed be helpful tools to identify unintended emissions, but these emerging technologies do not provide direct, or acceptably accurate, quantification of emissions upon which to base a waste fee.

Truly accurate quantification technology for methane emissions is still years away from being made commercially available. Instead of mandating the use of these types of indirect technologies, EPA's focus should be on directly reducing emissions from known sources—such as replacing gas-driven pneumatic controllers.

6. EPA should allow for a hierarchical GHG emission calculation approach similar to what is afforded in criteria pollutant emission inventories

As companies seek to improve the accuracy of their reported emissions, EPA could better fulfill the purposes of the GHGRP and the IRA by allowing more methods by which reporters can determine emissions. Most reporters have been submitting GHG reports to EPA for at least 6 years (G&B), if not 12 years (Gas Plants), and GHG reporting programs have come a long way in their maturity. As such, EPA should consider ways to move away from a reporting regime focused on consistent calculation methods among reporters and move toward a reporting regime focused on improving the accuracy of reported emissions. EPA should move toward a hierarchy of calculation methods, similar to how many states structure criteria pollutant emission inventory calculation requirements. Typical hierarchies include:

- Direct measurement (e.g., stack testing)[7]
- Manufacturer specifications and test data
- Emissions factors (generally supported by direct measurement data)
- Emissions quantification (algorithm-based estimates)
- Generally accepted calculation tools (e.g., ProMax, Glycalc, E&P Tanks, etc.)
- Engineering calculations
- Mass balance estimates

Operators use data and calculation methods that best represent emissions, and these methodologies—all valid in the context of emission inventories—can differ on an equipment-to-equipment or facility-to-facility basis. GPA supports the use of direct measurement and testing *as an option*, alongside the option to use emission factors derived from empirical data. This approach allows operators to use the best data available while avoiding inefficient and unnecessary mandates to collect direct measurements when other methodologies yield acceptable emission estimates. Importantly, operators should also be allowed to utilize equipment, facility, or company measurements instead of emission factors to reflect emission reductions (and increases) that would not otherwise be accounted for by emissions factors alone; this flexible approach recognizes different methodologies, measurements, and factors are best utilized in differing circumstances based on the precise application of technologies in specific contexts.

Additionally, Subpart W does not generally allow for downward adjustment of emissions to account for controls. As additional methane controls and mitigation methods emerge, calculations need to be flexible to reflect real reductions in emissions. For example, if a company has flyover and/or smart pigging programs to reduce pipeline emissions, the rule currently doesn't provide a way to reflect the emissions reductions achieved by those programs. As such, the rule should be expressly revised to account for those reductions by allowing operators to apply an emission reduction factor, or control percentage, if they have programs in place to reduce emissions.

[7] I.e., direct quantification of emissions using established testing protocols.

7. **EPA should allow calculation flexibility for all sources, as discussed above, but if it does not, certain sources must be allowed to use equipment, facility, or manufacturer-specific data**

GPA has identified several sources for which it believes the option to use equipment, facility or manufacturer-specific data in lieu of prescribed emission factors should be expressly included in any governing regulatory provisions. These are emissions sources where data and information specific to the individual equipment, facility, and/or manufacturers—including direct measurements—have the potential to be more accurate than the relevant emission factors. These equipment types are:

- Uncombusted methane from engines, i.e., methane slip (if this emission source is included in the waste fee, which GPA argues it should not be in comment 1)
- Pneumatic devices not currently covered by the existing GHGRP draft rule (i.e., allow monitoring of continuous bleed pneumatic devices)
- Fugitives (quantification from OGI surveys)
- Rod packing emissions

These are all sources where proven direct measurement techniques exist and operators should be allowed the option to use such data, or equivalent data from manufacturers and/or comparable sources at a facility, if it is available.

8. **Allow operators to report emissions based on best available data to avoid multiple "sets of books" on GHG emissions**

There are a multitude of driving forces on GHG reporting. These include EPA's GHGRP, the proposed SEC climate-related disclosure rules, and various voluntary reporting frameworks (e.g., GHG Protocol, NGSI, ONE Future, OGMP 2.0). Operators are often required to provide different sets of publicly available GHG data due to the rigidity of the GHGRP and the simultaneous need to state GHG emissions more accurately or differently in other reporting frameworks and publications. A waste fee based on data from the inflexible GHGRP only exacerbates this problem. Operators will be put in the position of paying waste fees based on emissions that are likely inaccurate (either too high or too low based on best available data) while also needing to justify that expense alongside the publication emissions data under other reporting frameworks. EPA should ensure that its GHGRP emissions reflect the best available data. Providing for sufficient flexibility by allowing the most accurate, real-world data to be reported into the GHGRP is crucial to avoiding the multiple "sets of GHG books" problem.

9. **Throughput should be based on natural gas throughput, not methane throughput**

The IRA states that the Administrator shall impose and collect the waste charge on the reported metric tons of methane emissions that exceed 0.05 percent of the **natural gas** sent to sale from or through a covered facility. It is clear that the legislative text prescribes that the waste charge is to be based on total natural gas and not just on the methane portion of the natural gas. GPA notes this distinction because other methane intensity protocols are based on methane throughput, but the legislation is clear that throughput is to be based on total natural gas.

10. Throughput should align with an appropriate interpretation of "a facility"

"A facility" within the context of the IRA should align with an appropriate interpretation of a facility (not the equipment-level "affected facility" used in OOOOb/c, nor the basin-level "facility" used in Subpart W). Throughput should similarly be based on discrete sites (i.e., each gathering and boosting compressor station). Any other interpretation would result in arbitrary treatment among industry segments and would lead to significant uncertainty as operators attempt to parse out what exactly is and is not a "facility" and how to correctly assess facility throughput. To address this potential confusion, EPA should revise Subpart W throughput reporting elements for gathering and boosting to allow reporters to reflect true facility throughput and define "facility" as explained below.

If EPA utilizes existing regulatory definitions to define a "facility," implementation of the IRA's language will be particularly challenging in that the terms "facility" and "facilities" have vastly different meanings in Subpart W and OOOOb/c, and those meanings themselves do not necessarily align with the public's understanding of what these words mean. In OOOOb/c, the "affected facility" is an individual piece of equipment (or group of equipment, like all the natural gas-driven pneumatic controllers at a gas plant). On the opposite side of the spectrum, under Subpart W, a gathering and boosting "facility" includes all gathering and boosting emission sources within a basin, which is usually a large geographic area spanning many counties and sometimes many states. Neither the OOOOb/c nor the Subpart W gathering and boosting facilities definitions are consistent with a general understanding of the word "facility." The IRA states, "the term 'applicable facility' means *a facility* within the following industry segments…." (emphasis added). GPA suggests that EPA use the simplest interpretation of the term, which is that "a facility" is a single site, and not specific pieces of equipment within that site, nor the aggregation of hundreds of sites within a geographic area. We think this is straightforward and "bridges the gap" between OOOOb/c and Subpart W.

Current Subpart W requirements address throughput differently depending on each industry segment, and this has significant ramifications for implementation of the waste charge provisions of the IRA, particularly if "facility" is not defined for purposes of the waste fee. For instance, under current Subpart W requirements, the gas through each transmission compressor station is reported on a per-transmission-compressor-station basis (98.236(aa)(4)(i)). However, Subpart W only requires reporting of volumes into and out of a gathering and boosting *basin* (98.233(aa)(10)(i)-(iv)). Reporting throughput at the gathering and boosting basin boundaries does not adequately capture "intra-basin" movement, e.g., natural gas that moves through multiple gathering and boosting compressor stations within a single basin. Since emissions generated from a facility are a function of the facility throughput, this is a significant disparity. EPA can address this disparity by modifying or adding Subpart W throughput reporting elements for gathering and boosting that allow reporters to align with other industry segments and reflect true facility throughput for assessment against the waste charge.[8]

[8] *See* GPA's comments on this matter in our comments for "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36,920 (June 21, 2022), Docket ID No. EPA-HQ-OAR-2019-0424.

11. Special consideration should be given to natural gas liquid fractionation plant throughput and/or emissions

Under Subpart W, natural gas liquid ("NGL") fractionation plants (which solely fractionate NGL) are required to report methane emissions as "onshore natural gas processing facilities," but NGL fractionation plants do not process natural gas and <u>therefore have no natural gas throughput</u>. The facilities receive bulk NGLs (C2+ mixture) and fractionate them into separate NGL products (C2, C3, C4, C5+). Methane emissions at these facilities primarily come from fuel gas system fugitive leaks and stationary combustion emissions. The statute bases the waste fee on natural gas throughput, which NGL fractionation plants do not have, and so to ensure regulatory certainty, EPA should explicitly state that NGL fractionation plants are entirely excluded from the waste fee. EPA should further clarify in its final preamble that it was the intent of Congress to base the waste fee on natural gas throughput, and therefore the Agency has no discretion to apply the fee to NGL fractionation plants.

Even if EPA believes it has discretion to apply the waste fee to NGL fractionation plants, the Agency should recognize that doing so is inappropriate given the nature of these facilities. As such, EPA would need to develop an entirely different method of applying a "waste fee" threshold. Options include:

- Provide a pathway for plant NGL throughput to be converted to a natural gas throughput equivalent for calculating the waste emissions threshold; or
- Provide a pathway to allocate reported Subpart W methane emissions to each product handled by a facility (i.e., x% of emissions are associated with natural gas throughput and should be included; y% of emissions are associated with NGL throughput and can be excluded)

12. GPA offers suggestions with respect to "exemption for regulatory compliance" based on GPA's proposed interpretation of "facility" above

The IRA offers relief from charges for sources that are in compliance with standards at least as stringent as those described in the OOOOb/c preamble published November 15, 2021. The exact language is, "Charges shall not be imposed pursuant to subsection (c) on an applicability <u>*facility*</u> (emphasis added) that is subject to and in compliance with methane emissions requirements…." GPA offers the following considerations for implementing this exemption.

When a facility (the simple interpretation, "a single facility" (e.g., a compressor station)) is in compliance with OOOOb/c, then the methane emissions from that facility should not be subject to the waste charge. This aligns with the text of the IRA and is the most straightforward approach to implementation of the waste emissions charge.

In addition, EPA should consider that distinguishing between methane emissions that are from sources subject to, and in compliance with, OOOOb/c and those that are not may result in significant emissions accounting challenges, especially for companies with hundreds, thousands, or tens of thousands of facilities. As such, while EPA should *allow* reporters to distinguish between emissions that are exempt from charges and those that are not, EPA should not *mandate* this. In particular, if a company is below the charge threshold regardless of OOOOb/c applicability/compliance, it should not be required to undertake the substantial work of parsing out emissions subject to and exempt from the charge.

Further, GPA has concerns about which facilities will be considered "in compliance" (or not) with OOOOb/c standards. This may not be straightforward, and EPA should consider initiating a separate proceeding to solicit comment on this issue. As an initial matter, GPA supports EPA's consideration of distinguishing between "material compliance" and minor deviation. For example, if there is a minor recordkeeping deficiency, that should not render a facility in noncompliance for purposes of the waste fee exemption. As another example, if upon annual measurement of compressor rod packing emissions, the emissions are found to be greater than 2 scfm, that source should not be considered in noncompliance, particularly if the operator takes immediate corrective action. Indeed, EPA should consider a broad safe harbor for timely corrective action to avoid noncompliance and the loss of an otherwise appropriate exemption.

GPA is also concerned that the legislative "exemption for regulatory compliance" from the waste emission charge could be interpreted to exclude combustion methane slip emissions, since the proposed NSPS Subparts OOOOb and OOOOc do not address this source category. As noted above, there is currently no practical or feasible way to control these emissions. The lack of ability to seek fee relief for regulatory compliance for stationary combustion emissions is further evidence that these emissions should not be included in this fee program.

Next, GPA requests that EPA provide subject facilities with the ability to seek a "determination by the Administrator" that certain state rules are *already* at least as stringent as the proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 Fed. Reg. 63110 (November 15, 2021)). In other words, operators should not have to wait until the Administrator approves OOOOc state plans, which will likely not happen for several years, to seek relief from fees on facilities that are already subject to acceptably stringent methane reduction rules.

Finally, the IRA states, "Charges shall not be imposed… upon a determination by the Administrator that… methane emissions standards and plans have been approved and are in effect in all States with respect to the applicable facilities." EPA should provide an interpretation of this language that gives as much flexibility as possible, and not punish operators for a particular state's poor performance preparing its methane reduction program. If a company operates in multiple states and only one of those states does not have approved methane standards, it would be unreasonable for EPA to refuse to exempt the company from charges for facility emissions in the states that impose such emission standards.

13. EPA should allow a pathway for fee exemption for voluntary adoption of emission standards

The IRA provides a pathway for fee exemption for regulatory compliance. EPA should allow operators to adopt compliance practices on an early or voluntary basis and provide fee relief for these operators. This is a win-win scenario that achieves early emission reductions. Allowing a pathway for early compliance also prevents subjecting operators to unnecessary fees merely because compliance standards have not been approved by EPA or are caught up in legal proceedings.

EPA should also consider whether OOOOa compliance satisfies certain aspects of the November 2021 OOOOb/c proposal and whether those OOOOa sources are potentially exempt from waste fees. In any case, EPA must provide a pathway for these OOOOa sources (or OOOO sources, or KKK sources, or any sources) to voluntarily "trigger" OOOOb.

14. Waste charge should be based on "finalized" Subpart W data

The IRA requires basing the waste emissions charge on Subpart W reported emissions. The GHGRP reports are due to the agency by March 31 of each year. EPA then reviews the data and may ask companies to correct errors or make other changes. Companies may also provide revisions to the reported emissions after March 31. Once EPA concludes its data review, the data is "finalized" in the August timeframe, and EPA then makes the information available to the public. Although companies may make changes to previously reported emissions after this publication of the reported emissions, we encourage EPA to base the emissions fees on what has been reported to EPA by the "finalization" date. We suggest this approach to mitigate accounting challenges that could occur when historical changes are made to reported emissions (and negate the need to track either underpayments or overpayments). Alternatively, EPA could structure the payment timeline like some state emission fee programs, where fees are calculated and assessed in arrears (for example, two years in arrears). This would allow time to make material corrections to emissions prior to any fee payments. If EPA implements a payment structure that would necessitate payment adjustments, then a time limit must be established, and it must be based on the reporting year, not on when the data was most recently submitted. For example, if in 2027 EPA identifies an error in a reporting year 2024 report that necessitates a correction, the timeframe should **not** be "reset" to 2027.

15. EPA should involve stakeholders in Subpart W form testing early

Subpart W data will, for the first time, be associated with fees, and it is critical that changes are implemented with stakeholder feedback to ensure e-GGRT, Subpart W forms, and XML schema are working correctly. GPA strongly encourages EPA to provide the draft XML schema and draft revised reporting forms to reporters for review and testing. In the past, doing so has led to the identification of errors and resulted in significant improvements. Additionally, final forms and schema should be published at least 6 months prior to the due date of the first affected reports. Many midstream operators are reporting data for hundreds of assets and have thus developed automated processes for populating forms and/or schema, which will need to be updated to reflect any changes EPA proposes. Additionally, because fees (and possibly SEC reporting) will now be tethered to this data, reporters need time to implement repeatable and auditable reporting processes. In the past, EPA has often not released schema until late January (mere weeks before the reporting deadline), and this has compounded challenges during the demanding annual reporting process.

16. EPA should prioritize engagement and flexibility

EPA asks a number of questions related to the IRA's incentives program provisions. GPA does not address all of those questions in these comments but does believe it is appropriate to respond to EPA's request for information on metrics for measuring success and ensuring accountability of the waste fee program.

EPA should not adopt inflexible measures for assessing success or ensuring accountability at this stage. The agency has never before implemented a waste emissions fee program for methane for the natural gas industry. The IRA program differs in many fundamental ways from other Clean Air Act programs. Creation of this waste fee program is a new and unique one for EPA: as such, especially in early years of the program, EPA should adopt policies that encourage engagement with the agency rather than a punitive approach while initial implementation of the program and complex issues of first impression are decided and addressed.

Accordingly, success and accountability can best be addressed through transparency in emissions reported and fees assessed. EPA should reward companies for their involvement in helping the agency develop the program and consider adopting an approach that allows for flexibility in the initial years of the program with the potential for further revisions, as necessary or appropriate, based on experience with implementation. Indeed, the GHGRP already includes provisions to ensure the success of the emissions reporting requirements and the accountability of companies subject to the program's requirements. The waste fee builds on that program and can reasonably rely on its existing success and accountability measures.

GPA therefore suggests that EPA use its authority and funding under the incentives provisions of the IRA to support companies that are subject to the waste fee in their efforts to comply and implement Congress's intent for the program. Reserving additional accountability and success measures until implementation has been fully realized by EPA and its partners in the regulated community is the appropriate course of action.

Attachment C

February 13, 2023

Via electronic submission (http://www.regulations.gov)
Attn: EPA-HQ-OAR-2021-0317
United States Environmental Protection Agency
EPA Docket Center
WJC West Building, Room 3334
1301 Constitution Avenue NW
Washington, DC 20004

Re: EPA-HQ-OAR-2021-0317; Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector, 87 Fed. Reg. 74,702 (Dec. 6, 2022)

Dear Sir or Madam:

GPA Midstream Association ("GPA Midstream") appreciates this opportunity to submit comments on the U.S. Environmental Protection Agency's ("EPA") supplemental notice of a proposed rulemaking, 87 Fed. Reg. 74,702 (Dec. 6, 2022) (the "Supplemental Proposed Rule") regarding emission standards and guidelines proposed on November 15, 2021 pursuant to Section 111 of the Clean Air Act ("CAA") ("the November 2021 Proposal"). EPA claims that the Supplemental Proposed Rule is intended to further reduce air emissions from the Crude Oil and Natural Gas source category, which is of significant interest and importance to GPA Midstream.

GPA Midstream has served the U.S. energy industry since 1921 and has over 60 corporate members that directly employ more than 56,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids ("NGLs"), refined products, and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 396,000 jobs across the U.S. economy. GPA Midstream members gather over 77% of the natural gas and recover more than 80% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 380 natural gas processing facilities. In the 2019-2021 period, GPA Midstream members spent over $100 billion in capital improvements to serve the country's needs for reliable and affordable energy.

GPA Midstream members have extensive gas and NGL operations that will be significantly affected by many aspects of the Supplemental Proposed Rule. Many of GPA Midstream's concerns were previously expressed in our comments submitted to EPA on the November 2021 Proposal. *See* GPA Midstream, Comments on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Climate Review, 86 Fed. Reg. 63,110 (submitted January 31, 2022). GPA Midstream, therefore, incorporates and asserts as if fully included here, those previous comments, which are attached for ease of reference as Exhibit A.

Executive Summary

GPA Midstream has welcomed the opportunity to engage meaningfully with EPA during this rulemaking and during prior related rulemakings so that the Agency may hear directly from the midstream industry and better understand our business and the technical aspects of midstream operations. A fuller understanding of the midstream industry will ensure regulations are founded on sound assumptions about the nature of our operations and how such operations may be affected by proposed regulatory requirements. GPA Midstream also appreciates important revisions in approach EPA has made in formulating this proposal, now spelled out in regulatory text for public review. However, there remain issues important to GPA Midstream that we urge EPA to reconsider and revise in any final rulemaking. More specifically:

- EPA should revise the subpart OOOOb applicability date to no earlier than December 6, 2022. The November 2021 preamble did not provide any regulatory text, which is essential for establishing an effective date. Preambles are designed to provide description and interpretation, but it is the regulatory text that specifies the governing regulations. EPA should not take this unprecedented step of claiming preamble language is sufficient.
- GPA Midstream urges EPA not to adopt its proposed definition of "legally and practicably enforceable." Rather than provide clarity, EPA's proposal is inconsistent with the long-standing definition, overly restrictive, excludes work practices and other control options, and effectively prohibits the use of permits by rule and general permits. EPA should not upend the state permitting process, which has long relied on the current understanding of legally and practicably enforceable, as adoption of this legally-deficient proposed definition would prove unworkable in practice and would require significant time and resources to implement, for which EPA has not allotted in its proposal.
- EPA should remove the proposed mandatory "Super-Emitter Response Program," which would unilaterally grant unprecedented powers to private parties without authorization from Congress as neither the Clean Air Act, nor any other statute, authorizes EPA to create the program. Instead, EPA should first assess the effectiveness of new Subpart OOOOb and OOOOc regulations after the requirements have been implemented to determine whether additional measures would be needed to address larger emitting sources, within the bound of EPA's statutory authority. At most, EPA could establish a voluntary program to address so-called "super emitters."
- GPA Midstream renews its concerns regarding the feasibility and actual cost-effectiveness of EPA's proposal to adopt solar powered or electric powered pneumatic controllers.

Crucially, EPA's unsupported optimism in the wide-spread adoption of solar powered controllers and the use of electric controllers is misplaced, and EPA must provide appropriately for sites that have no reliable access to the electrical grid.

- EPA should revise the definitions of tank battery, centralized production facilities, and modification, base applicability determinations on actual data or valid engineering estimates, and provide a reasonable timeline for compliance with these new requirements for storage vessels.
- EPA should revise the proposed rules for control devices to provide appropriate flexibility and enhance clarity to avoid confusion, and EPA should fully consider costs and the limited availability of equipment in evaluating cost-effectiveness and setting deadlines for installation of devices in the midstream sector.
- EPA should revise proposed regulations governing reciprocating compressors and wet seal centrifugal compressors to ensure appropriate flexibility and provide additional clarity. Among other revisions, owners and operators should be allowed to combine flow across compressor cylinders, and work practice standards should be allowed, such as instituting a repair or replacement scheme, and allowing owners and operators to route rod packing emissions to a control device. These would alleviate significant technical difficulties involved in the proposed requirements. Further, EPA should defer the proposed standards for dry seal centrifugal compressors due to the absence of data supporting a technically feasible vent rate.
- EPA should revise the compressor station Leak Detection and Repair ("LDAR"), closed vent system, and alternative monitoring provisions to provide greater flexibility and reflect the practicalities of operations and monitoring.
- EPA should revise gas plant LDAR requirements and Appendix K to provide for a more reasonable monitoring framework. Among other changes, EPA should provide a more reasonable approach to dwell times, survey breaks, the operating envelope, and senior camera operator requirements in Appendix K.
- EPA's analysis of costs and benefits should be revised, as it includes significant errors and omissions regarding the midstream sector. In particular, owners and operators of gathering and boosting compressor stations do not own the gas that they process and, therefore, recoup no financial benefits from reducing lost gas as EPA assumed. Midstream facilities and upstream production facilities are not comparable for purposes of analyzing the cost-effectiveness of the proposed regulations, and EPA's cost analysis should be revised to reflect these differences. Further, several necessary costs were omitted, such as compressor monitoring costs, installation costs, and the need for vapor recovery units, and we urge EPA to consider these costs in determining whether regulatory requirements are cost effective.
- EPA should not rely on the social cost of methane for this rulemaking, as the interim values are deficient and have not been finalized. Significant comments were presented to the government interagency working group that set the interim values, and those comments have not been addressed by the working group or EPA. Those technical issues need to be considered and addressed, before relying on the social cost in this rulemaking.

- In a future rulemaking, EPA should include a reasonable interpretation of the waste emissions charge provisions of the Inflation Reduction Act. In particular, EPA should fairly apply the "exemption for regulatory compliance" provided in this new law, including by adopting a reasonable, common sense meaning of "facility" and "in compliance," and to provide a "notice and cure" process that would allow sources reasonable time to cure any material non-compliance before a waste emission charge is assessed.
- Lastly, EPA's proposed requirements for states to show their state plan is equivalent to EPA's OOOOc emissions guidelines are contrary to the Clean Air Act. By seeking to shift power to EPA from that granted to the States by the Congress, EPA's proposal is contrary to the plain language of the statute, settled case law, and the core principles of federalism established by Section 111(d) of the Act. In all events, EPA should address any potential changes to the process for states to develop state plans under EPA's separate, pending rulemaking to revise subpart Ba, not this rulemaking.

As always, GPA Midstream stands ready to discuss EPA's proposal and provide information to further help the Agency understand the effect of rules on midstream operations and to assist with reasonable and appropriate regulation of our industry.

I. EPA Should Revise the Subpart OOOOb Applicability Date to No Earlier Than December 6, 2022

We further request that EPA revise the applicability date for subpart OOOOb to be, at the earliest, December 6, 2022—the date EPA published the Supplemental Proposed Rule in the Federal Register. EPA did not in fact propose the actual "regulations" when it provided an initial proposal in 2021. Without any actual rules to guide, as a matter of law and basic fairness, EPA should not seek to make November 15, 2021 the effective date for OOOOb.

First, the Clean Air Act does not authorize EPA to make the effective date of OOOOb a year before it published the actual regulations. We recognize that in CAA § 111(a)(2) the definition of "new source" suggests that EPA may apply a "standard of performance" to a new source as of the date of "proposed *regulations*." [1] But here, EPA did not publish a clear "standard of performance" in "proposed regulations" in November 2021 – it provided preamble language, requested comment on the numerous suggestions it outlined in that preamble, and promised to publish the actual regulatory text. The preamble, however, does not set a "standard of performance" and is not the governing "regulations," but is designed to inform the public about the meaning of the *regulations* that are codified in the Code of Federal *Regulations*. *E.g.,* 1 C.F.R. § 18.12 ("Each agency submitting a proposed or final rule document for publication shall prepare a preamble which will inform the reader, who is not an expert in the subject area, of the basis and purpose for the rule or proposal."); *see* Administrative Conference of the United States, Guidance in the Rulemaking Process: Evaluating Preambles, Regulatory Text, and Freestanding Documents as Vehicles for Regulatory Guidance at 4 (May 16, 2014) (distinguishing preamble language as

[1] A "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." 42 U.S.C. § 7411(a)(2); CAA § 111(a)(2).

"agency statements outside of those appearing in regulatory text that pertain to the meaning or interpretation of the agency's regulations or to advice about how to comply with the agency's regulations"). It has long been understood that those explanatory statements are distinct from the actual rules – and would be used by the courts and the public "in the interpretation of the agency's rules." United States Department of Justice, Attorney General's Manual on the Administrative Procedure Act at 32 (1947).[2] EPA cannot – and should not – seek to blur this long-settled distinction.

Second, in putting together the Supplemental Proposed Rule and preparing the regulatory text, EPA has added to and changed the approach it described in the November 2021 preamble. *See, e.g.,* Proposed Rule at 74,707 (summarizing changes made to Subpart OOOOb in response to comments received on the November 2021 Proposal). It would be grossly unfair and unsound policy for the agency to make a proposal retroactive, when sources and permit writers could not know even a general description of what EPA intended, let alone the regulatory text that would in fact govern. Indeed, in some cases, EPA did not even set out suggested outcomes, but only requested comment. For example, requirements for control devices on combustion sources were not in the 2021 preamble. The general request for comments for additional monitoring for control devices does not mean that flow meters and net heating value measurements and other requirements would be required, as EPA has now proposed. Moreover, unilaterally applying new regulatory text retroactively does not consider the practical implications, costs or burdens associated with retrofitting controls or monitoring equipment on existing controls in the segment.

Third, EPA's proposed November 2021 effective date runs counter to the U.S. Supreme Court's long settled rule against applying law retroactively. *Bowen v. Georgetown University Hospital*, 488 U.S. 204 (1988) ("Retroactivity is not favored in the law."). Congress must convey "the power to promulgate retroactive rules" "in express terms." *Id.* Nothing in the Act *expressly* provides EPA the authority to take the wholly unprecedented act of saying its preamble is sufficient. As such, by making OOOOb effective a year before EPA provided the public the regulatory text, it should be viewed as an impermissible retroactive application. *E.g., Marrie v. S.E.C.*, 374 F.3d 1196, 1207 (D.C. Cir. 2004) ("In the administrative context … 'a rule is retroactive if it 'takes away or impairs vested rights acquired under existing law, or creates a new obligation, imposes a new duty, or attaches a new disability in respect to transactions or considerations already past.'").

Fourth, even assuming for the sake of argument that EPA had the authority to apply its December 6, 2022 proposed regulations to sources that commenced construction after November 11, 2021, EPA should not do so. Good policy should afford affected facilities fair notice of the actual regulations – the regulatory text – before potentially being subject to those requirements. This is especially the case here, in light of the extraordinary complexity of the proposed regulations – layered onto the already confusing history surrounding the past decade of regulation of oil and

[2] That was the governing principle underpinning the requirement in the Administrative Procedure Act to require a "statement of basis and purpose of rules issued," so as to "with reasonable fullness explain the actual basis and objectives of the rule." H.R. REP. NO. 79-1980, at 259 (1946); S. REP. NO. 79-752, at 201 (1945), as available in ADMINISTRATIVE PROCEDURE ACT, LEGISLATIVE HISTORY, 79TH CONG., S. Doc. No. 79-248, 1944-46, 225 (1944-46). That statement is the explanation – not the "rule."

natural gas production, midstream, transmission and storage. Moreover, in the Supplemental Proposal EPA has proffered no actual justification for adopting this unprecedented approach. It makes no effort to consider the impracticality, burdens and costs imposed on sources that had no actual regulatory text to consider – and to weigh those against any purported benefits of this harsh retroactive approach. There is no data, analysis or other information. As such, we urge EPA to reconsider its intended effective date.

At the same time, GPA Midstream also recommends that EPA include provisions in the final rule that would allow and facilitate those owner/operators that have existing affected facilities covered by OOOOa to opt-in to OOOOb requirements for some or all of their facilities that are presently covered by OOOOa. This would be a voluntary measure for those owner/operators who wish to comply with what EPA determines in its final OOOOb regulation to be the current BSER for their facilities. Those owner/operators would opt-in because they are committed to achieving the reduced emissions and improved level of environmental performance that EPA would expect from implementing the expanded emission controls and other requirements in the latest BSER in OOOOb. It would also facilitate the work of regulators overseeing and permitting those facilities, which could otherwise have different requirements at the same location with some equipment subject to OOOOa and some to OOOOb, if certain affected facilities are modified or reconstructed. It would also streamline owner/operator compliance programs, which should likewise improve compliance and overall performance.

II. GPA Midstream Urges EPA Not to Adopt its Proposed Definition of "Legally and Practicably Enforceable"

GPA Midstream explained in detail in its prior comments that the preamble outline of a revised definition of "legally and practicably enforceable" in the November 2021 Proposal required substantial revisions, because it was inconsistent with existing definitions of the term and lacked any record support for revising the long established term. *See* Exhibit A at 12-17. EPA has now proposed regulatory text for Subpart OOOOb that proposes to define "legally and practicably enforceable" with the same flawed elements on which we previously commented. EPA has included this regulatory text without responding to the comments of GPA Midstream and others on this issue in any meaningful way, or providing additional justification for the departure from the long-applied definition of this phrase, except to assert that the proposed definition was intended to provide clarity. 87 Fed. Reg. at 74,800. Therefore, for the same reasons we outlined in our previous comments, GPA Midstream submits that EPA's proposed definition of "legally and practically enforceable limits" (found in regulations related to storage vessels in §60.5365b(e)(2) and §60.5386c(e)(2)) is unsound and unjustified.

GPA Midstream reasserts and adopts those previous comments and objections as if fully stated here. Briefly: First, contrary to EPA's suggestion that this is codification of previous policy, EPA previously defined and used the term differently.[3] Therefore, regardless of EPA's intent, providing a new and different definition does <u>not</u> provide "clarity to owners and operators claiming

[3] *See* 40 C.F.R. §§ 49.152, 49.167; 76 Fed. Reg. 38,748 (July 1, 2011); *see also* Prevention of Significant Deterioration and Nonattainment New Source Review: Debottlenecking, Aggregation, and Project Netting, 71 Fed. Reg. 54,235, 54,240 n. 13 (Sept. 14, 2006).

the storage vessel is not an affected facility in NSPS OOOOb, due to legally and practicably enforceable limits that limit their potential for VOC emissions below 6 tpy." 87 Fed. Reg. at 74,800.

Second, rather than provide clarity, EPA's proposed definition—including quantitative production and operational limits, averaging time, parametric limits on performance testing, continuous monitoring, and recordkeeping and reporting thereof[4]—is inconsistent with the long-standing definition, overly restrictive, excludes work practices and other control options, and effectively prohibits the use of permits by rule and general permits. *See* Exh. A at 13-15. EPA has not provided any reasonable justification for this shift from its previous position.

Third, EPA should not upend the state permitting process, which has long relied on the current understanding of legally and practically enforceable. Indeed, EPA has approved the state minor source permitting programs, which are part of the states' implementation plans. Based on those programs, sources have obtained permits and relied on the presence and operation of its controls to meet its regulatory requirements, such as the limit on VOC emissions from storage vessels. By substantially revising this definition – and apparently effectively assuming that controls are not in place – EPA would dramatically change the permitting landscape. Moreover, it is really putting the cart before the horse. If EPA believes state minor source programs generally require revision, there is a process for that and EPA should follow that process of generally revising state SIPs, as opposed to attempting to make changes in this regulation.

Fourth, adoption of this legally-deficient proposed definition would prove unworkable in practice and would require significant time and resources to implement, for which EPA has not provided in its proposal. *See id.* at 17. Among other concerns, these sources do not have methane limits in permits now. EPA's new approach offers no guidance on how to assess whether a particular set of parameters is legally and practically enforceable to achieve a methane limit in that case. Further, prohibiting the use of permits by rule and general permits would impose enormous burdens on sources and state permitting authorities, for which the proposal makes no provision. This would have a cascading effect on Title V determinations across numerous sources, imposing substantial additional burdens and complexities on sources and states.

Nevertheless, should EPA adopt such flawed text, EPA should recognize that sources in good faith went to the regulator and obtained a permit under the applicable state minor source program. Thus, at a minimum, EPA should provide flexibility by phasing in the requirement - applying the new definition only when a source needs to apply for a new or revised permit or a permit renewal. Moreover, crucially, for all existing sources, EPA should be clear that existing permits authorizing a source to operate remain fully effective, pending state processing of new permits.

[4] Proposed Regulatory Text, at § 60.5365b(e)(2)(i)(A)–(F).

III. The Proposed "Super-Emitter Response Program" is Not Supported by the Record, Contrary to Law, Would Impose Undue Costs Without Any Demonstrated Benefit, and Has Significant Implementation Challenges

We urge EPA to remove the proposed "Super-Emitter Response Program" from any final rule. 87 Fed. Reg. at 74,746-55. EPA's overall proposal includes significant new measures to regulate emissions from designated facilities that will impose substantial requirements on thousands of affected facilities. Through these new regulations, EPA has stated its intention to reduce emissions, increase monitoring to detect and respond to leaks and other sources of emissions, and expand reporting and recordkeeping. Yet, EPA has not demonstrated the need for mandating this type of extraordinary additional "super-emitters" measure on top of and in addition to the extensive new proposed regulations. Even more importantly, as proposed, the program is contrary to law as neither the Clean Air Act, nor any other statute, authorizes EPA to create the program, which would give extraordinary power to private parties to unilaterally require action by other private actors.

GPA Midstream supports appropriate, legal measures to address and mitigate excess emissions based on the administrative record. The proposed super-emitters program is neither lawful nor based on an established record. Instead, we submit that the prudent policy for EPA is to move forward without a mandatory super-emitters program and assess the effectiveness of the new regulations (as we urge them to be adjusted) after these new requirements have been implemented to determine whether additional measures would be necessary and appropriate to address larger emitting sources, provided those measures fall within EPA's statutory authority. At most, EPA should consider developing a voluntary framework that does not deputize third parties as outlined in the proposal.

A. EPA Has Not Identified a Need for a Mandatory Super-Emitter Response Program

To begin, EPA should not include a mandatory "Super-Emitter Response Program" in a final rule because it is an additional regulatory burden that is not supported by the record. The Supplemental Proposed Rule introduces "super-emitter" events as very rare and "typically caused by abnormal operating conditions or malfunctions."[5] EPA then states that "the November 2021 Proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent … or detect and mitigate … most of these large emissions events."[6] Thus, EPA anticipates that implementing these new regulations would make "super-emitter" events

[5] 87 Fed. Reg. at 74,746-47; *see also id.* at 74,748 (the percentage of super-emitting sources is so small that "it is not cost-effective to impose additional inspection costs on every source"); *id.* at 74,749 (where a source is compliant with regulations "the EPA does not expect unintentional releases at these very high levels to occur in normal operations").

[6] *Id.* at 74747.

extremely rare.[7] That itself demonstrates that adopting this additional and extraordinary program is not justified by actual record-based evidence.

Moreover, regardless of how many larger emission events would remain, if any, a new quasi-enforcement program is not required to address them. EPA's proposal is not intended to address intentional venting as part of normal operations or maintenance. *Id.* at 74,747, n. 101. Thus, a "super-emitter" event would present an enforcement issue, not a new regulatory issue, as these events would only arise through violations of the regulations. *See id.* at 74,753 ("Where one of these facilities is determined to be the cause of a super-emitter emissions event, it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement"); *id.* (where flares cause a super-emitter event they are not in compliance with existing regulations).

We recognize that EPA claims this extraordinary program is necessary as "a backstop to address the large contribution of super-emitters to the pollution from this sector." *Id.* at 74,747. However, EPA offers no supporting data and provides no reason why traditional federal, state, and citizen suit enforcement mechanisms would be unable to fully address these events, if any occur under a new set regulations once finalized. EPA found additional monitoring would not be cost-effective, and thus, EPA's proposed program would not increase the availability of monitoring capabilities or the likelihood that sources will be monitored. Instead, the Super-Emitter Response Program would only change how monitoring information may be handled if an alleged "super-emitter" is discovered. The Supplemental Proposed Rule provides no actual data or any other credible explanation of why monitoring information cannot be used for traditional regulator responses, as may be appropriate under the Clean Air Act.

The Supplemental Proposed Rule also infers that these events are somehow different than other potential regulatory violations because they are intermittent. *See*, *e.g.*, 87 Fed. Reg. at 74,747 (stating that "many such large emissions events are intermittent and can occur at different sites over time"). To the extent that EPA is claiming that the intermittent nature of these alleged events presents an unusual problem for traditional state, federal, or citizen enforcement, it provides no data or evidence to support such a claim. In fact, many types of alleged environmental violations occur on an intermittent basis, yet they have been addressed with existing enforcement tools – and without deputizing private parties well beyond the authority provided by the Clean Air Act. To the extent that a facility is out of compliance and truly causing significant methane emissions, traditional enforcement mechanisms are available.

B. EPA Should Consider Creating A Voluntary Program

While GPA Midstream opposes a mandatory program for the reasons outlined here, we are generally supportive of initiatives to identify other large emitting events (as defined in proposed revisions to subpart W regulations, 40 C.F.R. Part 98) using satellite, aerial, mobile, or other advanced detection platforms, and to stop them. GPA Midstream members have participated in

[7] This is the best description in the record available to the public, given that EPA has not identified how many alleged "super-emitters" there are under current conditions or estimated a reduction in "super-emitters" if measures like the proposed rules were promulgated and implemented.

numerous voluntary programs, such as The Environmental Partnership to respond to observations made by satellite and aerial remote sensing platforms. We would encourage EPA to consider a voluntary program instead of the proposed program. It would provide a demonstration of the concept before fashioning a regulatory program within the bounds of current law. A voluntary program would also allow time for new OOOOb regulations to be implemented, providing real data as to whether a program like that proposed is necessary.

C. EPA Has no Legal Authority For the Proposed Mandatory Super-Emitter Response Program

Nothing in the Clean Air Act authorizes EPA to create an entirely new third-party enforcement program that not only stands outside of the Act's citizen suit provision, but lacks the safeguards that Congress considered necessary for third-party enforcement. Further, as discussed in more detail below, the Super-Emitter Response Program is inconsistent with how Section 111 defines sources and source categories.

1. The Super-Emitter Response Program is not Authorized by Congress and Ignores Statutory Protections for Citizen Enforcement

Congress has not authorized EPA to adopt this program. The Super-Emitter Response Program establishes a quasi-enforcement system where EPA would unilaterally delegate to a private party the authority to obtain injunctive relief against another private party – all without any express authorization by Congress or an order from either a court or a regulatory agency. This new private party enforcement system lacks any basis in the Clean Air Act, and is precisely the type of agency legislating the Supreme Court struck down in *West Virginia v. EPA.*

In fact, it not only is not authorized by Congress, this program would be an end-run around the limitations that Congress either expressly established on third-party enforcement or that it knew to be imposed through formal legal proceedings when it passed the Clean Air Act. These include, among others, the citizen suit notice provision under 42 U.S.C. § 7604(b)(1)(A) and the diligent prosecution bar under § 7604(b)(1)(B), as well as the need for citizen plaintiffs to demonstrate an ongoing Clean Air Act violation, establish Article III standing, and demonstrate to an impartial judge that injunctive relief is warranted. Nothing in the CAA authorizes EPA to run roughshod over these statutory and constitutional requirements and create entirely new private rights.

In short, the Supplemental Proposed Rule, despite acknowledging that the Super-Emitter Response Program would enforce existing regulations, refuses to recognize it for what it is: a private-party enforcement program.[8] Authorization for such a private-party enforcement system is not found in the Clean Air Act, and EPA does not claim that the Program is justified by an

[8] The Supplemental Proposed Rule also appears to say that EPA and state agencies could also initiate the Super-Emitter Response Program to obtain corrective actions. 87 Fed. Reg. at 74,752. The Supplemental Proposed Rule, however, fails to describe such an enforcement action as being grounded in either the Administrator's emergency powers under 42 U.S.C. § 7603 or any form of enforcement authority identified in 42 U.S.C. § 7413. With respect to State agencies, the Supplemental Proposed Rule never considers whether the Super Emitter Response Program is consistent with State enforcement authorities or processes.

ambiguity in the statute. Instead, the Supplemental Proposed Rule simply creates an entirely new private-party enforcement mechanism out of whole cloth, despite Congress establishing robust systems for administrative, civil judicial, criminal, and citizen enforcement. 42 U.S.C. §§ 7413(b)-(d); *id.* § 7604. EPA should not embark on this extraordinary and unlawful endeavor.

2. *An Unauthorized Third-Party Enforcement Mechanism is not a "Compliance Assurance Measure"*

Nor can the Supplemental Proposed Rule disguise its new proposed enforcement scheme as a "compliance assurance" measure. 87 Fed. Reg. at 74,753. Under this theory, the proposal asserts that allowing a private-party (or any enforcement agency) to unilaterally issue an order "to require corrective action to bring the facility back into compliance with the applicable standard or requirement" is merely "a backstop – an additional compliance assurance measure." *Id.* The term "compliance assurance" is not found in the Clean Air Act or defined anywhere in 40 C.F.R., Part 60, let alone in any NSPS regulation. Thus, the Supplemental Proposed Rule's attempt to "interpret" a new and unauthorized enforcement scheme is not an act of interpretation. And even if it was, the Super-Emitter Response Program would be inconsistent with the types of monitoring, testing, recordkeeping, and reporting programs that the affected facilities must satisfy that one would consider to be "compliance assurance" requirements. *See*, *e.g.*, 40 C.F.R. §§ 60.7 (notification and recordkeeping requirements by affected facilities for construction and operational changes, recordkeeping for unit startups, shutdowns, and malfunctions, installation of continuous monitoring devices); 60.8 (performance test requirements); 60.11 ("Compliance with standards and maintenance requirements" that includes performance testing, opacity observations, or continuous opacity monitoring); 60.13 (standards for continuous monitoring devices). Allowing third-parties to issue unilateral compliance orders is not a "compliance assurance" measure and there is no evidence that Congress ever contemplated such a measure within the Clean Air Act.

3. Section 111 Does not Authorize Shifting Source Categories Based on Compliance Status

EPA cannot avoid the strictures of the Clean Air Act by designating a new (but temporary) "super-emitters" source category. 87 Fed. Reg. at 74,752. Under this approach, a source would transition from being an affected facility under the Crude Oil and Natural Gas Facilities category to an affected facility under the newly-created "Super-Emitter" category when one private-party unilaterally claims another private party incurred a "super-emitter event." *Id.* Assuming the third-party's information is correct and the new "Super-Emitter" affected facility implements a corrective action, it would then presumably transition back to a Crude Oil and Natural Gas Facilities source. Or, put another way, a Super-Emitter designated facility will only come into existence where a Crude Oil and Natural Gas Facility source violates a Crude Oil and Natural Gas Sector Facility emission or work practice standard, and then cease to exist once the violation ends. That cannot square with the notion of a source category under CAA § 111.

Moreover, that EPA's approach is not well founded is confirmed by the proposed Best System of Emission Reduction ("BSER") for super-emitters, which EPA proposes to define as the new super-emitter source merely coming back into compliance with whatever pre-existing Crude Oil and Natural Gas Facilities emission standards or work practices that was purportedly violated.

See id. ("the BSER for super-emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super-emitter emissions event"); *see also id.* at 74,753 ("Where one of these facilities is determined to be the cause of a super-emitter emissions event, it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement"). Requiring action to bring a source back into compliance with the applicable rules is not a system of emission reduction – it is an enforcement action.

This unprecedented approach is also inconsistent with Section 111. The Administrator may create new source categories under 42 U.S.C. § 7411 (b)(1)(A) or sub-categories based on "classes, types, and sizes … for the purpose of establishing such [performance] standards." *Id.* § 7411(b)(2). Nothing in the statute allows for the Administrator to create a new source category consisting solely of facilities already included in another existing source category that are violating existing regulations. Nor could the Administrator create a sub-category of such facilities as the sub-category would not be created "for the purpose of establishing" any "standards." The only BSER work practice standards the Supplemental Proposed Rule would impose is an order for a source to cure any alleged violation without so much as a notice of violation, much less any formal enforcement action and the accompanying statutory and due process protections.[9] The Supplemental Proposed Rule is not an attempt to interpret the meaning of some ambiguous statutory word or phrase; it is attempting to impermissibly create an entirely new type of enforcement program that sheds the Clean Air Act's procedural mandates.

Further, the Super-Emitter Response Program deviates from EPA's longstanding practice of designating specific equipment, such as tanks, turbines, or engines as "affected facilities" under Section 111. Even fugitive emissions requirements are tied to specific equipment types, such as valves, connectors, or flanges. Here, however, the "affected facility" would be an entire site, containing various categories of affected facilities, and subject to what is effectively an arbitrarily selected bubble limit or site-wide cap of 100 kg/hour, applying to both planned and unplanned emissions.[10] Nothing in Section 111 authorizes EPA to use such an approach.

4. *A Super-Emitter "Source" Can Neither be a New Source Nor an Existing Source*

EPA may only regulate two types of sources under Section 111: new sources (including modified sources) and existing sources. 42 U.S.C. §§ 7411(b), (d). A Super-Emitter Source, as the Supplemental Proposed Rule contemplates it, cannot be a new source under Subpart OOOOb because a new source must be either constructed or modified. *Id.* §§ 7411(a)(2) (a "new source" is

[9] Nor is the Supplemental Proposed Rule able to characterize the Super-Emitter Response Program as merely "an additional work practice standard," as work practice standards must "reflect[ ] the best technological system of continuous emission reduction." 42 U.S.C. § 7411(h). An order to cure alleged regulatory violations is not a "technological system of continuous emission reduction."

[10] The 100 kg/hour threshold is essentially an emissions limit, but EPA did not rely on any health-based or environmental drivers to establish it. The threshold appears to be based on current or pending satellite detection capabilities. *See* 87 Fed. Reg. at 74,749.

constructed or modified after the publication of the standard of performance regulations), (a)(4) ("modification" requires a "physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source"). Here, a Super-Emitter Source would be created by an emission event, not any construction or modification.

Nor can Super-Emitter Sources be existing sources under Subpart OOOOc as an existing source is typically constructed and operating before either the approval of a state plan with existing source standards or the issuance of federal existing source standards. 42 U.S.C. §§ 7411(d)(1), (2). Here, however, a Super-Emitter Source is only created by an emissions event. Even if the source itself is 20 years old, its existence as a Super-Emitter Source post-dates the issuance of any state or federal existing source standards. And yet, as described above, the absence of construction or modification activities means it cannot be a "new source" under Section 111 either. The Supplemental Proposed Rule never addresses this conundrum, which only arises because Congress never contemplated a source category-shifting scheme like the one proposed here.

D. <u>The Supplemental Proposed Rule Fails to Consider the Full Range of Costs for the Super-Emitter Response Program</u>

The Supplemental Proposed Rule mistakenly claims that "[t]o the extent there are additional costs associated with the investigation or mitigation of these [Super-Emitter] events, the EPA expects that the costs would be minor in relation to the benefits of stopping such huge emissions event, making them obviously cost-effective." 87 Fed. Reg. at 74,754. EPA offers no data, study, or other hard analysis to support this conclusory assertion. For that reason alone, EPA should reconsider its approach. Regardless, EPA apparently assumes that every source receiving a "Super-Emitter" compliance order will, in fact, be the cause of an alleged super-emitter event and can cost-effectively resolve the alleged emissions. However, while there have been improvements in satellite and airborne imaging, few can provide an accurate designation of a "Super-Emitter" source.

Even with such a highly developed imaging platform, third-parties will have significant difficulty pinpointing exactly which source is the alleged "super-emitter," and most third-parties must do with far less sophisticated equipment and software. As framed, nothing would constrain one private party from merely sending notices to multiple sources knowing that, at most, only one of the recipients is potentially responsible. On the contrary, EPA proposes to protect third-parties who are sending the notices in such a situation: "the failure of the operator to find the source of the super-emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier." 87 Fed. Reg. at 74,750. Yet, each recipient would have to investigate their facility or facilities in response to the notice. This will mean diverting personnel, or having to hire new personnel or contractors, to investigate potential violations or malfunctions, often at remote unmanned locations (and some of which are difficult to access during the winter months), without any hard evidence those facilities are the source except the assertion of another private party. Despite EPA's conclusion that the Super-Emitter Response Program is "obviously cost-effective," 87 Fed. Reg. at 74,752, the Supplemental Proposed Rule seems to give the actual costs and burdens that would be involved minimal consideration. In fact, if a company receives multiple notices per week, regardless of whether those notices are accurate or not, the time and resources required to respond would be immense. If EPA proceeds with this approach in some fashion, it should review fully and carefully the full range of costs associated with this type of program.

E. If EPA Proceeds With This Program, the Agency Should Develop a Program With Robust Governing Requirements

While GPA Midstream urges EPA not to proceed with a mandatory program, if EPA moves forward, there are important issues for EPA to consider before proceeding to finalize any regulation. Moreover, consistent with the requirements of the Administrative Procedure Act, EPA should afford the public an additional opportunity for comment before finalizing the details of any program.

1. *EPA Should Revise the Applicability Threshold and Nomenclature it Uses for the Program*

As an initial matter, GPA Midstream recommends that if the agency pursues this approach, it should align the threshold for notification with the proposed revisions to EPA's Greenhouse Gas Reporting rule, 40 CFR Part 98, which has a proposed reporting threshold for "large emission events" of 250 tonnes methane carbon dioxide equivalents (or 10 tonnes of methane). Applying a 24-hours timeframe for such events, this would result in a threshold of approximately 415 kg/hour. Should EPA increase the Subpart W threshold, we would recommend EPA aligning this program accordingly. Likewise, we suggest EPA align with the phrasing of "large emission events" in subpart W, in lieu of "super-emitter."

2. EPA Should Be Clear That Notice May Be Given Only if the Observed Emissions Are Due to Unplanned Events of a Persistent Nature Warranting a Response

As proposed, there is no validation that the observed emissions are unplanned occurrences or upsets of a persistent nature warranting the type of evaluation and response contemplated by the program. Singular observations of emissions from remote sensing technologies may constitute an observation of a planned or authorized activity that is part of normal facility operations, such as a blowdown or other authorized short term events (an engine startup) or short term malfunctions (a stuck dump valve) that vent gas at a high rate, but for a short period. Third-party observations may estimate these emissions as exceeding the threshold, but the actual estimated emissions may be well below the threshold.

Accordingly, EPA should provide that, operators/companies notified of an observation, should not be subject to reporting and corrective action if the event was a) associated with normal operations or maintenance activities and/or b) the observed emissions event is determined by the operator to not exceed the applicability threshold. To implement this, GPA Midstream recommends that for an emissions observation to be deemed as a persistent emission event for which a notice may be submitted, the observation must have been made between two distinct time intervals (such as 3 hours apart).

3. EPA Must Publicly Specify the Criteria Used to Approve Third-Party Notifiers and the Detection Technologies They Use

Under EPA's framework, the agency would designate "people with specialized equipment and expertise," 87 Fed. Reg. at 74,749, who could become third-party notifiers – but, EPA has not detailed fully in regulatory text the actual criteria that it would propose to use to make such designations. In the preamble description, EPA's approach is circular: third-party applicants would demonstrate their technical expertise by demonstrating their technical expertise. *See*, *e.g.*, *id.* at 74,750 (application would "demonstrate[ ] the potential notifier's technical expertise in the specific technologies and detection methods … [t]his demonstration would include technical expertise in the use of the detection technology and interpretation, or analysis, of the data collected by the technology"). This would leave approval to EPA's sole discretion without any real explanation of the criteria that EPA applied or why they approved any particular applicant.

We urge EPA to reconsider that type of approach. Instead, any program should provide the specific criteria for considering whether a third-party has the true "expertise" and qualifies for this role – and allow a notice and comment process to provide stakeholders the opportunity to comment on proposed third-party notifiers. That would be consistent with how EPA accepts applications, vets and allows for public input on proposed members of boards or for peer review. Further, GPA Midstream would urge EPA to be fully transparent about the criteria it is considering and allow for public comment before finalizing any criteria. Only by being fully open and public about the approval criteria, would the program have any potential credibility.

4. Third-Party Notifiers Should Have a Formal Affiliation with the Detection Technologies They Use to Have the Necessary Expertise

One criterion that EPA should adopt is that any third-party notifier must be employed by or directly contracted to, the company that makes or operates the monitoring technology that the notifier would use to monitor emissions. A strong affiliation with the manufacturer is necessary as few people outside of the company will understand accurately and fully how to use the highly specialized equipment that EPA is contemplating (*e.g.*, satellite imaging) or interpret their results. Although a person may be provided with basic training by the manufacturer, this is not true "expertise" in the technology and how detected data is translated into emissions data. Such expertise only comes with extensive experience and a real understanding of how the detection technology works, which would often involve an understanding of proprietary "black box" computational and analytical methods not available to the public. As such, EPA should specify that third party notifiers will not include individuals merely reviewing publicly available online data from outside sources (like Carbon Mapper or Climate Tracer) that then notify operators based on their observation of Carbon Mapper information.

As an alternative absolute minimum, EPA should require notifiers who meet other criteria to be certified in a specialized training program provided by the manufacturer of the technology, with demonstrated time in the field utilizing the technology overseen by a company expert to develop sufficient expertise to reliably measure and attribute relevant data. That is what EPA requires for other forms of testing and monitoring, and at a minimum, we urge EPA to be consistent and apply the same approach here.

Moreover, we also urge EPA to consider how unfair it would be for EPA to retain broad discretion to approve private parties, who would be granted extraordinary powers to require other private actors to take action and potentially expose other private parties to enforcement actions or negative public perception, without providing strict and transparent qualifications. It is particularly unfair given the stringent training requirements EPA imposes on industry personnel and their contractors on a wide range of matters – and in this area, the stringent standards EPA has imposed on the senior OGI camera operators that regulated parties must use.

5. *EPA Should Impose Standards and Protocols for Detection Technologies on Par With Those Industry Must Follow*

GPA Midstream would likewise urge EPA to develop and impose criteria on the third-party detection technologies that may be used under any Super-Emitter Response Program. At present, the proposal offers no criteria, leaving room for third-party detection equipment that is not reliable, and thus, could be used to compel another private party to invest substantial time and resources unnecessarily, as well as to create a public perception regarding an industry entity that is unfair and unjustified. Before finalizing these new criteria, EPA should make the proposed criteria available for public comment, as required by the APA.

Among other requirements, EPA should require approved third-parties to implement and document protocols established by equipment manufacturers for how they calibrate, use and regularly maintain detection equipment in a fashion similar to proposed Appendix K, which includes exceptionally detailed proposed mandates for OGI use (from maximum wind speeds to operator break times). Yet, as framed in the proposal, EPA appears to allow for approval of third-party detection equipment upon the barest showing of theoretical functionality – a standard that EPA does not follow for monitoring or compliance monitoring generally. New test methods or monitoring techniques must go through rigorous review by technical experts and public scrutiny before EPA allows their use – and often not until the technology or the technique has first gone through lengthy testing and review by knowledgeable standards setting bodies, such as ASTM and others. This type of rigor should be applied to any technology that would be used for a proposed program, along with a public process for review and comment on the technology. Any less rigorous approach would, again, not only lack credibility – but would arbitrarily impose requirements on industry that it would not impose on those bringing quasi-enforcement actions against industry.[11]

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[11] Although GPA Midstream views the Super-Emitter Response Program as unlawful under both Section 111(b) and 111(d), EPA appears to believe that the program also will be applied to existing sources through Section 111(d) state plans. *See* 87 Fed. Reg. at 74,753 (stating that most super-emitters would be violating "the proposed NSPS OOOOb/EG OOOOc."). The Supplemental Proposed Rule never addresses how EPA will evaluate state plans implementing the Super-Emitter Response Program and the discretion state agencies may have in approving third-party notifiers and the detection technologies they use. EPA should not apply this program to existing sources unless and until it addresses these and other issues regarding extending this program in a separate proposal subject to public comment.

6. The Proposed Regulatory Text's Description of Detection Technologies Highlights the Need For a More Detailed Proposal

Where EPA has provided general descriptions of technologies that would be allowed under this proposed program, the draft regulatory text - specifically the categories of "Satellite detection of methane emissions," "Remote-sensing equipment on aircraft," and "Mobile monitoring platforms" – highlights the need for EPA to consider these technologies and their use further, offer a more detailed regulatory proposal, and allow for public input. Proposed §§ 60.5371b(a)(1)-(3).

First, the proposed text conflates the concepts of detection and quantification. All of the listed categories of technologies involve remote sensing technologies that detect methane emissions – but they <u>do not</u> directly measure emissions. At most, these technologies may rely on proprietary algorithms to estimate remotely sensed concentrations (commonly expressed in ppm-m) and convert those into a mass emissions rate (such as kg/hour). EPA should recognize that these technologies can only provide a rough estimated emissions rate. They do not provide a "quantified emission rate" as the proposed text asserts. *See* Proposed §§ 60.5365b(j), 60.5371b, 60.5371b(b)(4), 60.5371b(e)(ii)(D).

Second, while these technologies (if properly calibrated, operated, and maintained) may be able to detect methane emissions, each of these technologies have documented accuracy limitations.[12] EPA has provided no independent evaluation or other rationale for accepting the listed technologies as accurately detecting methane to a degree that they may be used as tools to compel investigations and corrective actions by affected facility owners and operators. Further, as noted above, it does not appear that EPA plans to impose any protocols on how these technologies are used or their results interpreted. For example, if the technology's field study data shows an error in emission estimates that ranged from -50% to 100%, a measurement should only be valid as it relates to this program if it is still over the 100 kg/hr threshold assuming the potential error. These types of nuances in data interpretation need to be thoughtfully considered and explained. OGI cameras are comparatively mature technologies, yet EPA would use proposed Appendix K to impose restrictive mandates on how they are used, and who may use them. The absence of any similar protocols for the technologies in Proposed §§ 60.5371b(a)(1)-(3) not only undermines confidence in their use, but effectively implements an arbitrary "no rules" policy for these technologies.

Accordingly, to improve the confidence in use of these technologies, EPA should create a detailed protocol through which these technologies prove their accuracy (including maintenance and calibration requirements) and provide assurance that changes made to proprietary algorithms are not made without agency approval. Further, in view of inherent limitations with certain

[12] The tools used to evaluate an emissions event have error bars for a single "measurement" ranging from +/- 17% at the most accurate end to +/- 70% for the types of events that occur in the field. Heltzel, R., *et al.*, Understanding the Accuracy Limitations of Quantifying Methane Emissions Using Other Test Method 33A, *Environments* 2022, 9, 47, https://doi.org/10.3390/environments9040047; Halley L., *et al.*, Assessment of Methane from Oil and Gas Production Pads Using Mobile Measurement, *Envt'l Sci. & Techn.* 2014 *48* (24), 14508-14515.

technologies (e.g., satellite/aerial detection capability is limited due to weather conditions), EPA should specify conditions under which these technologies are suitable for emissions detection.

Third, the term "mobile monitoring platform" is vague. EPA should provide the public with fair notice of exactly what platforms may be qualified for use by third-party notifiers and proffer specific guidelines on how each of the defined set of platforms may be used to support a notice under this program.

Further, if EPA intends "mobile monitoring platform" to mean that third-parties may use drones, we urge EPA to consider fully the implications of approving and encouraging the use of that technology, as the proposal provides no procedures or limitations on the use of drones. Private parties flying drones over or through a facility not only could be an illegal trespass, but it would undoubtedly present a major safety hazard, including at unmanned facilities. Accordingly, EPA should develop proper monitoring procedures to prevent third party notifiers from placing themselves or others at risk of personal injury or jeopardizing the security of an operator's property, including clear direction that third party notifiers must not be allowed to encroach on an operator's property to conduct monitoring.

7. *The Supplemental Proposed Rule's Restrictions on Petitions to Disqualify Third-Party Notifiers is Unlawful and Should be Revised*

In addition to establishing strict criteria for approving notifiers, GPA Midstream suggests that the process for petitioning to disqualify a third-party notifier be revised.

Currently, EPA has proposed that "[a]ny owner or operator that has received more than three notices of a super-emitter emission event at the same well site, centralized production facility, or compressor station from the same third-party may petition the Administrator to remove that third party from the approved list." Proposed § 60.5371b(a)(4). GPA Midstream commends EPA for recognizing that, by tendering enforcement powers to private parties without legislative direction, this extraordinary program could be abused and used as a tool for harassment. However, owners and operators should be able to petition EPA to disqualify a third-party notifier at any time and without respect to the limitations listed by the proposed regulatory text. *See id.* (petition permitted only after three notices at the same facility, petitions may not be used to dispute technology accuracy, disqualification limited to "meaningful, demonstrable errors" or failure to observe event threshold).

The proposed restrictions on submitting a petition violate the Administrative Procedure Act. That requires "[e]ach agency" to "give an interested person the right to petition for the issuance, amendment, or repeal of a rule." 5 U.S.C. § 553(e). The Administrative Procedure Act does not authorize EPA to limit, condition, or otherwise restrict the filing of such petitions. And the decision to approve a third-party notifier easily meets the definition of a rulemaking. Such decisions are not only final (as opposed to "merely tentative or interlocutory") but impose rights and obligations "from which legal consequences will flow." Bennett v. Spear, 520 U.S. 154, 178 (1997) (internal quotations omitted). Here, EPA will authorize specific third-parties to exercise enforcement rights that other members of the public may not. Once an affected facility receives a notice from such a party, the Super-Emitter Response Program would legally compel the owners or operators of those facilities to undertake an investigation and response, including a potential corrective action. This makes EPA's approval of third-party notifiers a rulemaking under the Administrative Procedure Act and, as a consequence, EPA is prohibited from restricting the right of petition.[13]

At a minimum, we would urge additional revisions to the petition and review elements of any program. For one, as written, the ability to petition only applies after three improper notices at the same well site, centralized production facility, or compressor station. However, given that operators have multiple sites, GPA urges EPA to incorporate a cap across an entire operator's asset base, such as a maximum of six improper notifications per rolling 12-month period per parent company. Further, there should be clear provisions for restricting third parties that are ultimately removed from the approved list. EPA should make clear that individuals removed will be permanently prevented from reenrolling in the program. In addition, a provision should be included to cover an entity that may employ more than one notifier. So, where the third-party notifier is employed as part of a notifying entity, that entity should be removed from the approved notifier list for a period of at least one year. After the one year period, the entity may re-apply to be re-approved.

8. The Notification and Response Procedures Should Be Improved to Provide More Guidance to Both Notifiers and Sources

The Supplemental Proposed Rule's notification and response procedures require various revisions and significantly more detail to provide guidance to both third-party notifiers and those receiving a notice.

First, as noted, there needs to be validation that the observed emissions are of a persistent nature warranting the type of evaluation and response contemplated by the program. Absent data from two distinct time intervals, the notice should be deemed incomplete to which no response would be required.

Second, proposed § 60.5371b(b)(7) only requires a third-party to notify the owner or operator of the site "as soon as practicable." EPA does not define what is "practicable." This is a significant concern as the ability to verify any large emission event and, if verified, the cause of the event, will diminish greatly with time. Delays in receiving notice would therefore frustrate the owner or operator's investigation. GPA Midstream suggests that EPA require that notifications be submitted no later than five days after the third-party made the observation through a detection technology specified under any final rule – and only for observations that are made after the technology has been properly vetted under any final rule. This will ensure that the third-party provides actionable information to the affected facility so that the owner or operator may effectively and efficiently deploy resources to evaluate the notice. Moreover, a short timeline

[13] Of course, given that EPA's approval of a third-party notifier is a rulemaking subject to the Administrative Procedure Act, any proposed approval of a third-party notifier must be subject to the Act's public notice and comment process.

reduces the likelihood of unnecessary time and resources are invested in evaluating and reporting on an observation that a company/operator has already identified and abated.

Third, the Supplemental Proposed Rule provides no guidance on how third-party notifiers can accurately identify the owner or operator of an affected facility or provide any direction on notification. In the field, ownership and operation is often more difficult than anticipated given that co-located or adjacent facilities are common (*e.g.*, sites where both a production operator and a centralized production facility operator are on the same or adjacent properties), as are joint ventures where only one company has operational responsibility. If a third-party notifier can accurately identify the owner or operator, guidance on what constitutes an effective notice to the affected facility is important because the proposal would impose very short deadlines for evaluating the notice, and implementing a corrective action plan that are triggered by receipt of the notice. Without such guidance, however, owners and operators may end up exceeding these deadlines because the third-party notifier sent the notice to the attention of a general community relations employee that does not understand the significance of such a notice, former employees, employees on vacation, or any number of company contacts that are not designated to handle such environmental concerns.

Accordingly, EPA should provide guidance in a final rule on how the notifier is to know whom to notify at a company – and the method by which actual notice should be deemed to have been provided. Specificity is critical, given the responsibilities EPA is proposing. The rule should not, for example, allow notifiers to rely on phone numbers or other contact information posted on facility locations or general contact information as the formal contact for receiving official notice on behalf of the operator/company.[14] The contact could, for example, be the same person or contact that is the designated representative for Subpart W. EPA should also detail how changes to the company contact would be handled when the named contact(s) are not at work (PTO/Vacation/Sick leave) or have been reassigned or retired. The rule should also address co-located facilities to avoid undue confusion, given the short response time, and specify the responsible party for a joint venture - GPA Midstream recommends that the notice be provided to the operator.

Fourth, the Supplemental Proposed Rule provides no guidance as to how an owner or operator should respond to multiple notifications for the same alleged super-emitter event. Presumably, if an owner or operator receives, for instance, three separate notices of an alleged event, it should perform only one investigation or response applicable to all three notices. The proposed regulatory text, however, should be clarified to avoid a possible interpretation that would read the text as requiring a separate investigations into the same alleged super-emitter event. EPA should clarify that an investigation is tied to an alleged large emissions event, not to each notice of the alleged event.

Fifth, the Supplemental Proposed Rule does not contemplate what should happen where an owner or operator identifies and abates a potential emissions event and then subsequently receives

[14] The complexity of providing notice to a company or operator is a further reason why GPA Midstream had proposed in its previous comments that any private party notice should be handled through the regulators, not by a direct action from another private party. Notifications would come to the agency first and then sent to the company.

a third-party notice for this event. Such scenarios are certainly possible given that the Supplemental Proposed Rule's "as soon as practicable" standard means that affected facilities could receive notices weeks after an emissions event. GPA Midstream proposes that, in such instances, the affected facility should be able to respond with a letter identifying (1) the cause of the emissions event, (2) how it was abated, and (3) when it was abated. The affected facility should not have to waste its resources performing a *post hoc* mock investigation and corrective action under proposed §§ 60.5371b(c)(1)-(10) for an incident that was already resolved.

Sixth, proposed § 60.5371b(c) requires the recipient of a notice to initiate a "root cause analysis" within five days of receiving the notice and complete both the "root cause analysis" and an initial corrective action within 10 calendar days of receiving the notice.[15] References to "calendar days" should be changed to "business days." Unlike large petroleum refineries or chemical plants, which have employees working 24 hours a day, seven days a week, most midstream sites are unmanned. Engineering staff at the company's headquarters or a regional office would conduct the investigation. These are salaried employees, not shift workers, that typically work Monday through Friday (excepting federal and state holidays where offices are closed) during normal business hours. Further, investigation time may be consumed by time needed to travel to and from the sites, some of which are relatively remote. Therefore, EPA should afford owners and operators 10 business days (or two weeks) to complete their investigations.

Finally, GPA Midstream is concerned with the proposed process to have all notices sent by third-parties, and subsequent reports by the recipients, posted to a public website. 87 Fed. Reg. at 74,750. For one, EPA should not post any information about a third-party notice until the responding party's report is final – and no information related to the event should be publicly available. Moreover, EPA should include procedures to ensure that the database of publicly available notifications will be maintained to ensure the accuracy of provided notices. EPA should undertake its own review of the documentation before posting, as notifications deemed to be invalid or incorrect or made by a notifier deemed unqualified should not be posted. Indeed, fundamental fairness demands that, where a recipient cannot verify a third-party notice of a super-emitter event, or demonstrates that the notice was invalid (*e.g.*, was not an unplanned occurrence or upset but was due to normal operations, did not exceed the threshold, used an unapproved detection technology, identified the wrong source, *etc.*) it should not be posted or removed from the website if already posted.

F. The Term "Root Cause Analysis" is Inapt for Describing the Evaluation Required to Respond to a Notice

GPA Midstream recommends that EPA strike refences to a "root cause analysis" throughout the Supplemental Proposed Rule and regulatory text as a notice recipient is not actually required to conduct one. It is only required to conduct various inspections and to document various issues listed in proposed §§ 60.5371b(c)(1)-(10). This is not a "root cause analysis" in that it is not a formal systematic investigation, using multiple potential methodologies, into the potential causes of an incident that identifies corrective actions to reduce the probability of similar future incidents.

[15] As discussed below, the Supplemental Proposed Rule requires an investigation or response, not a root cause analysis.

See, *e.g.*, OSHA-EPA, Fact Sheet, The Importance of Root Cause Analysis During Incident Investigation (Oct. 2016);[16] Dep't of Energy, Root Cause Analysis Guidance Document, DOE-NE-STD-1004-92 (Feb. 1992).[17] Root cause analyses take significant amounts of time – far longer than the 10 days required by the Supplemental Proposed Rule. Therefore, EPA should remove all references to "root cause analysis" and replace them with a more generic and appropriate term, such as "investigation" or "evaluation," *e.g.* Revised Proposed 60.5371b(c)("Within 5 days of receiving the notification of a super-emitter emissions event, you must initiate ~~a root cause analysis~~ **an evaluation** to determine the cause of such emissions and to determine appropriate corrective action… The ~~root cause analysis~~ **evaluation** and initial corrective action …")

G. The Effective Date of the Program Should be Deferred Until EPA Completes a Process of Approving Notifiers and Appropriate Technologies

GPA Midstream also recommends that the effective date for implementing any program be deferred until EPA completes the process of approving notifiers and defining and approving appropriate technologies. As outlined above, EPA should defer any program until it has developed robust governing requirements in a supplemental rulemaking that allows the public a full opportunity to comment on those requirements. At a minimum, any final rule should state that only observations/identifications made no sooner than 180 days after the rule is final would be subject to the new requirements in the program. We suggest a minimum of 180-days to provide EPA with necessary time to review and approve certified third-party notifiers and to approve qualified technologies.

IV. GPA Midstream Renews its Concerns Regarding the Feasibility and Actual Cost-Effectiveness of EPA's Proposal to Adopt Solar Powered or Electric Powered Pneumatic Controllers and Pumps

Although GPA Midstream supports certain aspects of the proposed requirements for pneumatic controllers, the Supplemental Proposed Rule did not address several significant issues we raised in comments on the November 2021 Proposal. The most important of these concerns include EPA's unsupported optimism in the wide-spread adoption of solar powered controllers and the use of electric controllers despite many sites lacking reliable access to electricity. This will necessarily require the use of gas- or diesel-fired generators to power instrument air systems. Further, EPA continues to underestimate costs by assuming that midstream facilities, such as gathering and boosting compressor stations are analogous to oil and gas production well sites. We explain, at length, that midstream facilities and upstream production facilities are simply not comparable for purposes of analyzing the cost-effectiveness of the proposed regulations.

A. Zero Emission Controllers are not "Affected Facilities" Subject to Regulation

Since the applicable facility is the pneumatic controller itself, and a zero emitting controller is excluded from the class of applicable facilities regulated under proposed § 60.5365b(d), the

[16] *Available at*, https://www.osha.gov/sites/default/files/publications/OSHA3895.pdf.

[17] *Available at*, https://www.standards.doe.gov/standards-documents/1000/1004-std-1992/@@images/file.

installation of zero-emitting controllers would remove the site from regulation. In this scenario, an owner or operator would be able to use any means available to power zero-emitting controllers as there would be no regulatory restrictions on how those controllers may be powered. GPA Midstream requests that EPA confirm that any controllers that are not driven by natural gas (and are, thus, zero emission) are not subject to proposed § 60.5365b. Indeed, imposing requirements on sources that do not emit pollutants is unnecessary and beyond EPA's Clean Air Act authority. EPA's authority under Section 111 is to address new sources of emissions that "contribute significantly to, air pollution …." 42 U.S.C. § 7411(b). Likewise, a standard of performance is a "standard for emissions of air pollutants" that represents "the degree of emission limitation" that is achieved by "the best system of emission reduction." § 7411(a)(1). Clearly, where there are no emissions at issue, the source cannot and should not be subject to regulation.

B. GPA Midstream Supports Aspects of the Supplemental Proposed Rule's Pneumatic Controller Requirements

GPA Midstream supports the Supplemental Proposed Rule's definition of "modification" and "reconstruction." Further, GPA Midstream agrees that natural gas-driven pneumatic controllers should be treated in the aggregate as an "affected facility" and not individual gas-driving pneumatic controllers. We also support the proposed regulatory language allowing for like-kind replacement of existing individual pneumatic controllers without causing the controller to become an "affected facility."

C. EPA Should Limit Application to Facilities With Reliable Access to Grid Power

Sites, such as centralized production facilities and gathering and boosting facilities, would need reasonable access to available and reliable grid power in order comply with the controller requirements in Subparts OOOOb and OOOOc. Proposed §§ 60.5390b and 60.5390c would require pneumatic controller affected facilities to either use zero-emitting controllers (*e.g.*, electric drive control valve or instrument air with power supplied by either access to electricity or solar power) or zero-venting controllers (*e.g.*, self-contained and routed to a process). GPA Midstream requests that any final rule should limit applicability of these requirements to facilities with ready access to reliable offsite power, such as grid access.

From a practical standpoint, many new compressor stations and centralized production facilities are being installed in areas with access to grid power and are being designed to operate pneumatic controllers with instrument air. Where access to grid power is not present, for either new or existing affected facilities, many owners and operators would install diesel- or gas-powered generators in order to supply controllers with electric power and either instrument air-driven controllers or electric drive controllers and valves under voluntary or ESG-driving initiatives. As GPA Midstream detailed in our previous comments, the electric drive controller and valve option, and the solar power option, presents serious technical challenges that render them impracticable in nearly all instances. *See* Exh. A at 24-26. GPA Midstream also notes that relying on supplied or onsite power (*i.e.*, solar panels or on-site generators) poses a risk to operations in the event that power fails and results in a facility shutdown. Such a shutdown will effect upstream facilities, such as wells feeding into a compressor station.

A key element of this recommendation is determining what constitutes "readily available and reliable access to electricity." GPA Midstream recommends that to be "readily available" would mean that there is a nearby, operating electricity supply line with sufficient capacity for the site and would not require significant new construction by a third-party provider, such as a new tie-in or the installation of additional substations. With respect to "reliable access to electricity," GPA Midstream would recommend that this mean that a power source is not subject to frequent intermittent power losses (brownouts), as continuous power is necessary for safe, reliable operations. Further, a site also would be deemed to lack reliable access to power where the electricity service provider does not have the capacity to power facility operations. In many areas, GPA Midstream member companies are informed that electric service providers simply lack adequate capacity to provide power to our facilities.

Despite the importance of access to reliable grid power, proposed Subpart OOOOc does not recognize the clear distinction between existing facilities and truly new facilities, which have some flexibility in where they will be sited, and existing sources that do not. To address existing sources' lack of flexibility, GPA Midstream proposes that Subpart OOOOc requirements be subject to a site-specific technical and cost effectiveness review for connecting to the power grid or using onsite power generation, such as solar power or natural gas- or diesel-fired generator. It would also consider the costs of conversion, such as the installation of additional instrument air headers and piping. This type of review would be similar to the review for pneumatic pumps. If the review determines that these options are either technically infeasible or not cost-effective (*e.g.*, more than \$5,540 per ton of VOC or \$1,970 per ton of methane), then the owner or operator should be permitted to use natural gas-driving continuous low-bleed and intermittent-bleed controllers.

D. <u>The "Carbon Limits" Report is Flawed and Cannot Support Requirements for Zero-Emitting Controllers</u>

GPA Midstream does not believe that it is appropriate for EPA to rely so heavily on a single study, the "Carbon Limits" report, for the justification of zero-emitting controllers. As discussed in our January 2022 Comments, the Carbon Limits report has significant flaws in how it gathered information, preventing it from providing an accurate representation of the technical cost issues involved in using zero-emitting controllers at gathering and boosting stations. *See* Exh. A at 24-27. Neither the Supplemental Proposed Rule nor the November 2021 update to the Carbon Limits report addressed these flaws. Therefore, GPA Midstream incorporates its prior comments on the 2016 Carbon Limits report by reference.

GPA Midstream's overarching criticism of the Carbon Limits report is that it focuses almost entirely on the use of solar power at 22 production sites in Canada, Wyoming, Utah, and Peru. Further, the economic models it uses to support solar power and electronic controllers and valves are based on three model facilities with five, 10, and 20 pneumatic controllers at <u>production facilities</u>, *i.e.*, well pads. An evaluation of production sites is simply not representative of, or applicable to, midstream gathering and boosting operations which are significantly different from a well pad. GPA Midstream believes that the following issues also demonstrate that the Carbon Limits report is unreliable and cannot support the Supplemental Proposed Rule's requirements:

- The Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. There is no indication that the Carbon Limits report authors made any inquiry about whether solar power or electronic controllers and valves could be applied to midstream gathering and boosting operations. EPA has no rational basis to simply presume that these technologies will apply to gathering and boosting operations in the same manner as production operations, as gathering and boosting stations typically have a far larger footprint and substantially greater power needs.

- EPA should not require industry-wide adoption of technologies based on only 22 cases of adoption over three countries. This is simply too small of a sampling to support a determination that these technologies are technically feasible and cost-effective nationwide and in so many varying applications. Further, there is no indication that either the Carbon Limits report authors or EPA undertook any type of follow-up inquiry with the 22 sites in order to determine whether they had any challenges in using the technologies or whether they had stopped using them.

- The economic models supporting cost effectiveness are based on three well pad site configurations, ranging from five to 20 controller, with air compressors ranging from five horsepower to 20 horsepower, and generating between 2.5 and 60 cubic feet per minute instrument air. The Regulatory Impact Analysis appears to indicate EPA believes that gathering and boosting stations are analogous to the "large model facility" for production sites. Although the "large model facility" may apply to a small gathering and boosting station, moderate and larger gathering and boosting stations require far more. GPA Midstream members report the need for air compressors rated between 40 and 150 horsepower to generate instrument air at 400 standard cubic feet or more. This means that the needs of production well pads are simply not comparable to gathering and boosting stations. Additional operational and/or cost differences between production sites and gathering and boosting operations include the following:

    - The pneumatic devices used for the three model production sites are substantially smaller than most gathering and boosting compressor stations. These smaller scale cost metrics will not linearly scale up with larger facilities where new instrument air header and piping, additional pipe supports, or an extended pipe rack may be necessary.

    - The installation costs for a header to the pneumatic controllers, in Table 5 of the Carbon Limits report, is for a new installation. Retrofits often require the existing methane pipe header to remain in place as a source of fuel gas to on-site equipment, such as compressors, fired heaters, combustors/ thermal oxidizers, or flares. A new parallel air header needs to be run to all instruments, adding significant costs depending upon the location, site layout, available space, and the need for additional pipe supports. Put simply, the installation costs at a well site are not useful in determining the cost-effectiveness of retrofitting gathering and boosting operations.

    - The stated installation costs in the Carbon Limits report is much lower than what GPA Midstream member companies typically see. It does not appear that wire and miscellaneous electrical material were accounted for. Further, the installation labor time per each devices does not appear for the time to pull wire to each device. This may not be significant at small production sites with only a handful of devices, but for larger equipment, this will involve significantly more time and higher costs to install.

- In the midstream industry, typical total project costs are three to four times the major equipment cost for brownfield facilities. The Carbon Limits report improperly assumed only two times major equipment cost. It is not clear if the report properly accounted for hydrovacing underground inside the fence line, work permits, additional safety and personal protective equipment costs, and other issues that add to overall brownfields project cost.

- For greenfield sites, total project costs are typically two to three times major equipment costs. For instance, one of our member company's New Mexico central gathering facilities has 34 shutdown valves, 70 other pneumatic devices, and 34 diaphragm pumps. The site will install 150 horsepower of air compression (two 75 horsepower flooded screw compressors) for this relatively large operation. GPA Midstream's vendor quotes indicate that the skid price for these compressors, the dryer, wet/dry air receiver, and off skid star air receiver is approximately $250,000. *See* Exhibit E. Total project cost is anticipated to be approximately $1,050,000, which includes roughly $175,000 to route sufficient utility power to a location if that is required. This is an installation factor of 3.5 times the major equipment cost (not including utility power costs).[18] Yet, the Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation.

- Table 9 of the Carbon Limits report provides a cost comparison for the Sample C Site, the larger productions site. For the site with no electricity and using solar power, the report calculates $2,200 per device with the controller accounting for $2,000 of that cost. This means that the Carbon Limits authors assumed that it would cost only $200 per device for installing the device, installing a new panel, purchasing wire and miscellaneous electrical materials, and pulling wire from the panel to the device. In the experience of our member companies, these costs are underestimated by one to two orders of magnitude, depending upon the site's size and complexity.

- The Carbon Limits report assumes that, for a new site with electricity, the electronic controller option is only $1,950 per device. It is not clear why the controller cost is less than that for a site with no access to electricity, but even assuming the lowest potential controller cost - $1,500 – it is implausible that a company can install the device for only $450 each. Given the labor and additional materials described above, $450 in installation costs is severely underestimated.

- For a new site with electricity, the Carbon Limits report also assumes that grid instrumentation will cost only $50,000 for a 20 horsepower air compressor, leaving approximately $31,000 for installation, This is two to three times lower than typical

[18] A second member looked back at projects over the past 2 1/2 years and found a similar installation factor for their projects.

installation costs, which including building a foundation, setting the instrument air skid and air receiver, grounding the skid, running a new air heading to 22 devices, and running power to the new air compressor skid.

- At a retrofit site with no electricity, the Carbon Limits report assumed approximately $2,900 to install solar power and electric controllers. As the Carbon Limits report assumes the controllers are $2,000 each, this leaves only $900 to retrofit each valve with an electric controller, install a new panel, purchase wire and miscellaneous electrical equipment, and pull wire from the panel to the device. The owner or operator may also have to excavate and remove buried lines. Further, retrofitting goes significantly slower than for new installations. This means that Carbon Limits' installation cost assumptions are underestimated by at least one to two orders of magnitude depending upon site size and complexity.

- In retrofitting a site with no electricity using solar powered electric controllers and new control valves, the Carbon Limits report estimates a cost of $4,700 per device with each controller costing $2,000 and each control valve costing $2,500. This leaves a mere $200 per device to install the controller, valve, new panel, purchase wire and miscellaneous electrical equipment, and pull the wire. The Carbon Limits report evidently did not consider the need to shut in, isolate, and blow-down the process to be able to physically install the new valves into the piping, then remove isolation valves, purge, and pressure up before putting the equipment back into service.

- In retrofitting a site with electricity, using the electric controller option and existing valves, the Carbon Limits report estimates a cost of $2,700 per device with the controllers costing $2,000 each. This would leave only $700 for installing each controller – a process that goes far slower than installation on a new source and may require excavating buried lines.

- Finally, the Carbon Limits report estimated that retrofitting a site with access to electricity using electronic controllers and new control valves would cost approximately $4,600 per device with each controller costing $2,000 and each control valve costing $2,500. This leaves only $100 per device to install each controller and valve, involving shutting in, isolating, and blowing down the process, removing isolation valves, purging the system, and then re-pressuring before putting the equipment back into service. This is simply not credible and demonstrates that the Carbon Limits report's authors lack the understanding of midstream operations necessary to apply its findings to the midstream industry.

- The Carbon Limits report focuses on the reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power generation works best in areas with more sun. The study does not support the reliability of solar powered systems in areas of limited sun exposure, such as West Virginia, or in canyons and mountain valleys.[19]

[19] EPA has properly recognized this as an issue by proposing to exempt Alaska from this requirement.

In sum, although GPA Midstream appreciates the effort to attempt to update the 2016 Carbon Limits report, the 2021 update fails to support the Supplemental Proposed Rule as applied to the midstream sector. The report's dataset is too limited in number and too different in character for application to gathering and boosting equipment.

E. Several Aspects of the Controller Options are Neither Technically Feasible or Cost-Effective

GPA Midstream's January 2022 comments provided a significant discussion on the technical and cost challenges associated with solar powered controllers, electric drive controllers/valves, and the use of instrument air (with and without offsite power) despite EPA failing to provide proposed regulatory text. Although EPA has now provided the proposed regulatory text, the Supplemental Proposed Rule preamble does not address or respond to our prior comments. Therefore, we again raise the issues discussed in those comments along with additional relevant information. *See* Exh. A at 24-26.

1. Electrically Actuated Controllers Perform Poorly and are Unduly Expensive

Electrically actuated controllers should not be required for midstream equipment as they lack the speed and performance of gas-powered or air-powered actuators. For instance, they tend to have inadequate duty cycle ratings and their torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions to maintain a set point. Controller failures can result in overpressure events, releasing far more methane than that saved by electrically actuated controllers.

A controller failure is a serious concern for midstream operations, which have significant unmanned facilities. Hence, any repair requires sending personnel out to those facilities that are frequently found in remote locations. Further, electrically actuated controllers require the installation of a complex automated control system, which would require offsite monitoring using a Supervisory Control and Data Acquisition system—an additional cost that EPA does not appear to have included in its estimates. Any final evaluation of electrically actuated controllers should consider <u>all costs</u> associated with forcing a switch to electrical power. EPA should also allow midstream companies the option to continue to use, or install, a dual natural gas system as a backup for key controller functions. Such a natural gas backup system would be used in the case of air-actuated controller failure, loss of power, or other contingencies.

Although electrically actuated controllers can be installed in certain limited circumstances, they are more expensive with fewer options available on the market. Mandating their use would further drive up prices with manufacturers being unlikely to catch up to increasing demand until after the Supplemental Proposed Rule's compliance date.

2. *Solar Powered Controllers are not Technically Feasible*

The November 2021 Proposal asserted that "[a]t sites without electricity provided through the grid or onsite electricity generation, mechanical controllers and electronic controllers using solar power can be used." 86 Fed. Reg. at 62,203. At the time of the November 2021 Proposal, there was no indication that EPA had any information or experience with significant operational use of solar powered controllers on the scale that EPA was considering – literally at thousands of sites across the country in diverse geographic areas. Further, the November 2021 Proposal relied on the broad assertion that the Canadian provinces of Alberta and British Columbia have adopted non-emitting controller regulations. This, however, is highly misleading. British Columbia only adopted zero-emission regulations for newly constructed sources, while Alberta only requires that 90% of new sources use them, thus permitting some flexibility for new sites that cannot be constructed in a location that does not connect to line power. Moreover, neither province imposes a zero-emission requirement on existing sources. Rather, in both provinces, existing sources are subject to a 0.17 m^3/hr, or 6 scfh, limit. Not zero emissions.

The Supplemental Proposed Rule indicates that EPA remains just as optimistic about the use of solar powered equipment as it was in the November 2021 Proposal, claiming that "a solution based on solar energy would likely utilize a single array of solar panels to provide power to all the controllers at the site." 87 Fed. Reg. at 74,756. Yet, EPA has not acquired any additional information on solar powered controllers other than the update to the Carbon Limits report discussed above, which does not provide a reliable basis for imposing this requirement. Although the Supplemental Proposed Rule recounts and summarizes the significant number of comments criticizing solar powered controllers, 87 Fed. Reg. at 74,764, its only response was to reference the Carbon Limits report, which does not even attempt to address most of the issues that commenters raised.

EPA did offer that, where owners and operators are concerned about snow covering solar panels, the Carbon Limits report suggested that "these panels [be] placed vertically, eliminating snow cover on the solar panels." *Id.* EPA did not attempt to calculate how much sun exposure is diminished by vertical placement, whether this could also prevent ice accumulation, how much power generation would be diminished through snow pack, or whether solar panels could work with any placement in areas prone to blizzards and other serious winter weather. Nothing in the Supplemental Proposed Rule or the Carbon Limits report addresses the fact that reliance on solar power leaves sites subject to the weather and could be effectively shut down for days.[20]

What EPA has not considered is that, if a midstream site loses power, it can disrupt the entire upstream and downstream supply chain. Power loss at a site with electrical equipment raises environmental consequences, as well. Unplanned downtime can lead to additional emissions at both the midstream facility and the upstream well sites. Compressor stations can be forced to blow

[20] EPA's citation to a vendor's comment for the notion that zero-emission controller systems can successfully be used in all climates provides no support. 87 Fed. Reg. at 74,764, n. 151 (citing EPA-HQ-OAR-2021-0317-0838). The vendor's claim that solar powered air systems result in a 26% improvement in production is misleading as it is based on a single case study in the Wamsutter Basin of Wyoming during a month (January 2020) that was warmer than the comparison month (January 2019).

down equipment to the atmosphere or route blowdown emissions to a combustion device. In some circumstances, it may be forced to flare all incoming gas while the equipment is down in order to avoid a safety concern. Upstream well sites may be forced to vent or flare as well if a downstream compressor is not available. Also, shutting in wells generally does not happen immediately when there is midstream loss of power. It takes time to shut-in wells and until such time that the well is shut down, the gas must be vented or flared if it cannot continue to the downstream facility for processing and distribution. GPA Midstream asks EPA to reconsider this requirement and examine fully the technical difficulties, performance problems, costs, and consequences of power loss that will attend requirements to use solar powered controllers.

3. *EPA's Cost-Effectiveness Analysis is Inadequate for Gathering and Boosting Facilities*

EPA's cost modeling does not provide any reasoned basis to estimate cost-effectiveness for gathering and boosting facilities. The cost models only considered production and transmission facilities. They do not include gathering and boosting facilities – and to the extent that EPA claims to cover those facilities, the agency is inappropriately including gathering and boosting facilities as production facilities. They are not the same – and to treat them the same is arbitrary and capricious. Unlike production facilities, gathering and boosting facilities see no economic benefit from recovered gas. In addition, as explained above in detail, gathering and boosting facilities have much larger system requirements due to the larger number of controllers and the need for more powerful air compressors. Assuming that gathering and boosting facilities have roughly equivalent system requirements as production facilities dramatically underestimates costs. For instance, it appears that EPA is assuming zero high bleed pneumatic controllers, four low bleed devices, and 15 intermittent bleed devices for new facilities and one high bleed, four low bleed, and 15 intermittent bleed for existing facilities. These counts (19-20 pneumatic controllers) are only applicable to a relatively few number of very small gathering and boosting facilities.[21]

EPA's large plant model estimate $96,000 for a 20 horsepower air compressor to supply instrument air to 19 pneumatic devices. This severely underestimates the actual costs for gathering and boosting facilities. Based on GPA Midstream members' actual installation costs and vendor quotes, owners and operators of gathering and boosting facilities may spend $500,000 to $1,000,000 for instrument air systems at sites with available grid power. For sites that require onsite power generation, the cost could readily increase by an additional $400,000 to $1,000,000. GPA Midstream urges EPA to reconsider the costs for gathering and boosting stations – evaluating these midstream facilities as separate facility types, instead of treating them as being similar to much smaller production facilities.

[21] It is also unclear if EPA's pneumatic controller count included those used on emergency shut down ("ESD") devices. Many operators have installed ESD devices that utilize "intermittent" venting controllers. These devices only "vent" in an emergency and not routinely, like process controllers. However, the air system must provide adequate air to allow these devices to operate in case of an emergency.

F. Any Zero-Emission Requirement Should be Technology Neutral

Instead of requiring that midstream companies use specific types of equipment – despite significant performance and reliability issues – EPA should use a technology neutral standard. Since the Supplemental Proposed Rule did not consider, or respond to, GPA Midstream's January 2022 comments on this issue, we are incorporating those comments here by reference. *See* Exh. A at 26.

G. EPA Should Confirm that Diesel- or Gas-Fired Generators May Still be Used

GPA Midstream urges EPA to confirm in the final rule as it recognized in the November 2021 preamble that diesel- and natural gas-fired generators may be used to supply onsite power for instrument air systems or other electrical source needs (*e.g.*, electric valves, pumps, heat tracing, *etc*.).[22] Both of these types of generators are currently being installed to provide on-site power for instrument air systems, as allowed by states such as New Mexico. Although natural gas-fired generators are more commonly used, operators need flexibility in choosing which fuel source provides the more reliable and safer power generating option for the specific location. Issues affecting diesel- versus natural gas-fueled generators may include horsepower requirements, fuel quality, site elevation, access to fuel, available space for installation (diesel fuel requires additional storage vessel (s) for onsite fuel storage), *etc.* As addressed previously, relying on instrument air systems, or even solar powered systems, presents risks to facilities if the electricity supply is interrupted. Power loss can result in a facility shutdown impacting both the facility itself and upstream facilities. For these reasons, GPA Midstream requests that EPA expressly reconfirm that the final rule would allow both diesel- and gas fired-generators as options to supply power for instrument air systems for pneumatic devices or other electric devices (*e.g.*, valves).

H. EPA Should Define Several Terms Related to Pneumatic Controllers or Revise Those Definitions

GPA Midstream requests that EPA modify definitions for the following terms used in the proposed regulatory text for the pneumatic controller requirements: "intermittent vent natural gas-driven pneumatic controller," "natural gas-driving pneumatic controller," "non-natural gas-driven pneumatic controller," "pneumatic controller," "self-contained pneumatic controller," and "zero emissions controller." The absence of clear definitions for these terms can create confusion and potentially lead to unnecessary and unintended compliance issues.

- **Intermittent vent natural gas-driven pneumatic controller** means a **process control device that uses natural gas and** ~~natural gas-driven pneumatic controller that~~ is ~~not~~ designed to **not** have a continuous bleed rate but is instead designed and operated to only release natural gas to the atmosphere as part of the actuation cycle.

[22] 87 Fed. Reg. at 74,765 (EPA recognized that owner and operators may "elect to comply by installing and operating a generator").

- **Non-natural gas-driven pneumatic controller** means a~~n~~ ~~automated~~ process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position.

- **Pneumatic controller** means a~~n~~ ~~automated instrument~~ process control device used for maintaining a process condition such as liquid level, pressure, delta-pressure or temperature by changing valve position.

- **Self-contained pneumatic controller** means a natural gas-driven pneumatic controller ~~in which the motive gas is not vented to the atmosphere but captured in a closed vent system for process use or control such that there are no direct methane or VOC emissions from the controller~~ **that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions**.

I. GPA Supports the Exemption for Emergency Shutdown Devices But Requests Additional Clarification

GPA Midstream supports the exemption for controllers that act as emergency shutdown devices. *See* proposed §§ 60.5420b(c)(6)(i)(A); 60.5365b(d). However, we request that EPA clarify that the emergency shutdown device exemption is not limited to those devices at well sites, centralized production facilities, natural gas processing plants, and compressor stations. *See* 60.5365b(d) (defining pneumatic controller affected facility as being limited to these types of facilities).

J. GPA Supports the Proposed Definition of "Affected Facility" for Natural Gas-Driven Pneumatic Controllers That Allows for In-Kind Replacements

GPA supports the proposed definition of "affected facility" for natural gas driven pneumatic controllers that allows for replacements without triggering the modification requirements. Specifically, we understand that under this definition an "in-kind" replacement of a natural gas driven pneumatic controller would not be a modification "provided that less than 50% of the controllers are replaced at the same time." 87 Fed. Reg. at 74,758-59; Proposed § 60.5365b(d)(2)(ii) ("If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the pneumatic controllers at a site are replaced … within any 2-year rolling period …") This is a reasonable approach, as if EPA did not allow this, operators would be discouraged from voluntarily replacing high-bleed natural gas-driven controllers with low-bleed controllers. We also believe that replacing a natural gas driven high bleed pneumatic controller with a natural gas driven low bleed pneumatic controller or intermittent bleed pneumatic controller would not be a modification (as no increase in emissions occurs). And we believe that retrofitting a natural gas driven low bleed pneumatic controller to a natural gas driven intermittent controller would not be a modification (again due to no increase in emissions).

K. EPA Should Not Impose Recordkeeping Requirements for Exempt Controllers

GPA Midstream stated in its January 2022 comments that EPA did not explain how it had authority to require recordkeeping for components exempted from regulation or why companies would need to maintain records for components that would be obviously understood as being exempt upon inspection (*e.g.*, those powered by solar panels or using instrument air). *See* Exh. A at 28. Since the Supplemental Proposed Rule did not address those comments, GPA Midstream incorporates them by reference. Indeed, GPA Midstream highlights this point again to underscore its request that EPA confirm that regulatory requirements do not apply to and will not be imposed on sources that do not emit air pollutants.

L. EPA Should Extend the Implementation Timelines for Controller Compliance with Subparts OOOOb and OOOOc

GPA Midstream explained in its January 2022 comments that the midstream industry would require at least five years to retrofit existing sources for compliance with the controller requirements under Subpart OOOOc. *See* Exh. A at 28-29. Since the Supplemental Proposed Rule does not address or respond to those comments, GPA Midstream incorporates them by reference herein.

In addition, EPA should allow more than one year from publication of a final rule for retrofitting "new" sources subject to Subpart OOOOb to comply with the zero emission controller requirements. Several GPA Midstream member companies with operations in New Mexico, which already requires zero bleed or zero emission controllers at new facilities, are experience significant delays in the availability and actual delivery of instrument air system and related equipment. Further, those members are finding it difficult to secure the necessary contractor services. GPA Midstream believes that, if EPA finalizes its proposed zero emission controller requirements, these supply chain and labor issues will only become worse as the standards are applied nationwide for both new and existing sources, not just new sources in New Mexico.

V. EPA Should Revise the Definitions of Tank Battery, Centralized Production Facilities, and Modification, Base Applicability Determinations on Actual Data/Valid Engineering Estimates, and Provide a Reasonable Timeline for Compliance With These New Requirements on Tanks and Storage Vessels

GPA Midstream raises three main concerns with the Supplemental Proposed Rule's provisions for tanks and storage vessels. First, EPA should implement relatively minor revisions to the definitions of "tank battery," "centralized production facilities," "modification." Second, applicability determinations should be based on actual data or valid engineering estimates instead of highly overstated assumptions regarding maximum site throughput. Third, owners and operators will need additional time to comply with the storage tank provisions should they be finalized.

A. EPA Should Revise Definitions Used in the Supplemental Proposed Rule

GPA Midstream supports the regulatory text defining "tank battery," which is greatly improved from the description EPA included in the November 2021 preamble. However, GPA

Midstream would urge EPA to improve this definition further, by eliminating a provision requiring manifolding for vapor transfer. In addition, the definition of "centralized production facilities" should be revised to more clearly exclude compressor stations that are not part of producing operations. Further, the definition of "modification" for compressor stations should also be revised to differentiate between compressor stations owned by the well site owner and compressor stations owned by third parties who lack any control or influence over the well sites that send production and would not know about operational issues prior to the custody transfer point.

1. *EPA Supports the Revised "Tank Battery" Definition, But it Should be Further Revised to Exclude Vapor Transfer or Remove the Requirement for All Tanks to Route to the Same Control Device*

GPA Midstream appreciates that, after considering public comments, EPA now proposes regulatory text that would not include the term "adjacent" in the definition of "tank battery." 87 Fed. Reg. at 74,800. As discussed in GPA Midstream's January 2022 comments, Exh. A at 9, the concept of adjacency is vague, does not provide additional guidance to owners or operators, and is not relevant where storage vessels are manifolded together for liquid transfer.

EPA's proposed requirement to manifold the vapor space for tank batteries, found at § 60.5395b(b)(1), unnecessarily dictates how storage vessels are routed to controls. The Supplemental Proposed Rule states "that these changes reflect our intent that a group of storage vessels which are manifolded together by liquid line operate as a system and, as such, share the same control device." 87 Fed. Reg. at 74,800 (emphasis added). However, the Supplemental Proposed Rule provides no explanation, and cites no record support, for requiring all of the tanks in a tank battery to share the same control device.

While it is not unusual for all storage vessels in a tank battery to be routed to the same control device, this will not always be possible, such as when vessels store different contents. This means that, under certain circumstances, more than one control device and closed vent system would be required to control storage vessels across a tank battery, especially for storage vessels at existing sites. An owner or operator could find itself unable to comply with conflicting requirements. For example, where steel and fiberglass vessels are forced to share a common vapor space manifold, static buildup and grounding deficiencies will result in a severe safety issue, including the risk of an explosion. Additionally, if storage vessels are not located near each other, it may be better to install two separate control devices. Using multiple control devices for storage vessels does not significantly affect emission rates and will result in the same total emissions from the tank battery. Therefore, GPA Midstream proposes the following revisions to § 60.5395b(b)(1):

(b) Control requirements.

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, ~~you~~ **all storage vessels within the tank battery** must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through (iii~~v~~) of this section.

> (i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);
>
> ~~(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;~~
>
> (ii~~i~~) The tank battery must be equipped with a closed vent system that meets the requirements of §60.5411b(a) and (c); and
>
> (iii~~v~~) The vapors collected in paragraphs (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

GPA Midstream believes that these minor revisions will meet EPA's desire to have these emissions controlled and avoid safety concerns and other conflicts without affecting total tank battery emissions.

2. *EPA Should Revise the Proposed Definition of "Centralized Production Facility"*

EPA should revise the definition of "centralized production facility," as used in proposed § 60.5430b, because it does not clearly exclude compressor stations that are not part of producing operations. GPA Midstream suggests that the last sentence of the definition be revised as follows:

> A centralized production facility is located upstream of the **compressor station,** the natural gas processing plant, or the crude oil pipeline breakout station and is a part of producing operations.

GPA Midstream is concerned that the current definition does not clearly distinguish between a compressor station, which will have associated storage vessels, and a centralized production facility which may have associated compression. Storage vessels located at compressor stations would provide a function similar to a centralized production facility but they are not "part of producing operations." Without the proposed revision provided above, GPA Midstream believes there would be significant confusion as to how applicability determinations would be performed for storage vessels and which LDAR monitoring program would apply.

Further, the definition should exclude independent centralized production facilities that are not part of producing operations, such as where the centralized production facility is owned by a midstream company separately from production assets. Where a centralized production facility is owned and operated by a midstream company, that company cannot know whether a well site added equipment or fractured a well because there is no obligation for the production company to inform downstream processing companies. EPA should clarify that a centralized production facility that is not part of producing operations is not included in the definition.

3. *The Definition of "Modification" Should be Revised to Clearly Exclude Mere Increases in Throughput*

The current proposed definition of "modification," as applied to tank batteries at compressor stations, centralized production facilities (possibly including independent centralized production facilities, as discussed above), and natural gas processing plants, includes the mere receipt of "additional fluids which cumulatively exceed the throughput used in the most recent … determination of the potential for VOC or methane emissions." Proposed § 60.5365b(e)(3)(ii)(D). As discussed previously, the owner or operator of midstream tank batteries at compressor stations or natural gas processing plants have no control over the receipt of fluids from upstream production facilities owned by third parties. Midstream companies take possession of liquids at the custody transfer point and lack information regarding the upstream exploration and production company's production volume prior to that point. Hence, quite simply, these modification requirements are not feasible, as the midstream owner/operator is not the producer.

Moreover, attempting to define a change in throughput as a modification is contrary to law. Under the Act, a mere increase in throughput without any capital expenditure, other physical change to the equipment, or change in the method of operation is not a "modification." *See* 42 U.S.C. § 7411(a)(3). The Supplemental Proposed Rule is not only inconsistent with the statutory definition of "modification," but it is inconsistent with EPA's prior interpretation that a "modification" requires some physical change to a tank. *See* Letter from Valdus Adamkus, EPA Region 5, to Bradley Miller, Hamilton County Environmental Services (Mar. 25, 1996) (increase in vapor pressure resulting in increased tank emissions was not a "modification" under 40 C.F.R., Part 60, Subpart Kb because there were no physical changes to the tank). GPA Midstream is concerned that, unless the proposed definition of "modification" is revised to require a physical change or change in the method of operations, midstream owners and operators could find their equipment "modified" solely based on the decisions of upstream third parties and without taking any action themselves.

B. The Applicability Determination Methodology for Compressor Stations and Natural Gas Processing Plants Should be Revised

The Subpart OOOOb proposed calculation methodologies for compressor stations and natural gas processing plants should be revised. GPA Midstream appreciates that EPA incorporated our suggestion to create separate applicability determination criteria for compressor stations, but we have some new concerns, as described below. Given the new interpretation of "legally and practicably enforceable limits," and the lack of certainty regarding the enforcement of state-issued permits, the existing text and approach is no longer appropriate. Under the proposal, emission calculations for these sources would be based upon the projected maximum daily average vessel throughput derived from the maximum gas throughput capacity of each facility. In most cases, this would significantly overstate actual tank battery emissions. The effect would be to premise applicability determinations on the site's design capacity, not actual emissions or even engineering estimates of throughput used for New Source Review permit authorizations of the site. A methodology based upon the maximum gas throughput capacity is used to calculate potential to emit thresholds for New Source Review permits. However, condensate production is not easily estimated as it is a combination of liquid that drops out of field gas during compression and condensate that drops out of the gas along the pipeline to the station or plant. This is dependent on several factors, including weather conditions, that change throughout the year. EPA's methodology will ensure that many storage tank batteries would be deemed subject to OOOOb, even though they would be exempt based upon actual throughput data. As such, we urge EPA to allow for qualified engineering estimates, instead of design capacity.

For new compressor station sites, permit calculations are generally submitted prior to construction, based upon engineering estimates of liquid throughput based on expected gas design capacity. This is not the same as storage vessel design capacity, which may be much higher. For existing sites that are modified, existing throughput data is used in combination with engineering estimates of any expected throughput increase. In neither case would the maximum design capacity be used to estimate VOC or methane emissions from the storage tank battery. Engineering estimates based upon expected throughput are much more accurate than assumptions of maximum throughput capacity for the site. Additionally, in permitting hourly and annual emission limits, frequently the maximum hourly emission limit does not match the annual limit due to issues with variability in storage vessel throughput across an entire year.

Owners or operators must obtain a permit for any new tank battery, the reconstruction of a tank battery, or the modification of a tank battery (where a tank is added, total capacity will increase, or the actual throughput will exceed the current permit or most recent Subpart OOOOb determination). In each instance, owners or operators must submit an emissions estimate prior to startup. GPA Midstream suggests that engineering estimates, signed by a qualified individual or professional engineer involved with the project, be used in lieu of maximum design capacity. We understand that these estimates infrequently may underestimate the actual throughput once the site comes online. To account for this, we suggest that the throughput estimates be compared to actual operating data within 30 days of startup to ensure accuracy. This is consistent with current requirements under Subpart OOOOa and the definition of "maximum daily throughput."

C. Owners and Operators Need Additional Time to Comply With Storage Vessel Monitoring Requirements

The Supplemental Proposed Rule added monitoring requirements for storage vessel control devices than were not included in the Proposed Rule. The November 2021 proposal only provided general concepts for monitoring, recordkeeping, and reporting requirements but did not propose anything specific. *See generally* 86 Fed. Reg. at 63,201-02. Unlike with large, capital-intensive equipment, storage vessels can be put into operation quickly. In fact, a significant number of new storage tanks have been operating since EPA published the November 2021 Proposed Rule. These are currently operating without the newly proposed monitoring requirements, as those requirements were never explained in the November 2021 Proposed Rule. As we explain in these comments, as a general matter, EPA should not apply a November 2021 applicability date for any of these regulations. *See* Section I, *infra*. In the particular circumstance of storage vessels, if application of the monitoring requirements were to relate back to the November 2021 Proposed Rule, these sources would need to be retrofitted for compliance equivalent to an existing source as the equipment necessary for compliance with the new monitoring requirements could not have been incorporated into their initial design.

GPA Midstream requests that any date for storage vessel compliance be at least one year after the effective date of any final rule. This time is needed to determine what type of monitoring devices could be used for each specific application and budget for the additional equipment purchasing and installation. Given the large number of storage vessels used in the midstream industry, retrofitting will take a significant amount of time and resources.

VI. EPA Should Revise the Proposed Rules for Control Devices to Provide Appropriate Flexibility and Enhance Clarity to Avoid Confusion, and Should Fully Consider Costs and Availability of Equipment in Evaluating Cost-Effectiveness and Setting Deadlines

A. The Control Device Provisions Require Significant Revisions for Clarity

GPA Midstream appreciates EPA's intent to consolidate the proposed control device provisions into one section, but the resulting regulatory text requires some further clarification to ensure end users fully understand all of the requirements and do not unintentionally misunderstand monitoring and testing requirements. Accordingly, we suggest further streamlining and clarification to the control device section.

1. The Proposed Regulatory Text Should be Streamlined and Reorganized to Improve Overall Clarity

As a general matter, we urge EPA to consider streamlining and reorganizing the regulatory text to improve clarity. As written, the proposed regulatory language is extremely complicated and difficult to follow. As an example, proposed § 60.5417b explains "What are the continuous monitoring requirements for my control device?" This is an important section imposing binding obligations upon regulated owners and operators, however, the section has numerous layers of subsections. In this instance, the explanation of an owner or operator's obligations goes as far as § 60.5417b(d)(1)(viii)(C)(1). Further, constant cross-references to other sections and sub-sections makes it easy for readers to become lost, confused, or misinterpret the regulation's intent. For most of GPA Midstream's members, engineers and technicians manage regulatory compliance, not sophisticated legal counsel. Any finalized regulatory language should be in a more streamlined and simplified form, organized so that all of the requirements for specific control devices may be found in one place, and written so that those subject to the rules can clearly understand them.

2. EPA Should Clarify What May be an "Affected Facility" for the Control Device Requirements

The proposed regulatory text describes control device requirements for various "affected facility" types but that listing is incomplete. *See* Proposed § 60.5415b (including "well affected facility," "wet seal centrifugal compressor affected facility," "pneumatic pump affected facility" and others). Yet, there are multiple sections in the proposed regulatory text where a control device can be used to control emissions from a source, but it is not clear whether the source is subject to the testing requirements under § 60.18(d). GPA Midstream would like clarification on whether control devices used for those sources must be tested every five years.

Further, it is common for multiple equipment types, such as pneumatic pumps and rod packing vents, to be routed to a common control device. It is not clear if adding new equipment that are "affected facilities" under the proposed regulations to the common control device will make all equipment routed to the common control device affected facilities. EPA should clarify that equipment that is merely routed to the same control device as an "affected facility" will not cause existing equipment to become "affected facilities."

3. Proposed Regulatory Text Regarding Flare Requirements Should be Clarified

EPA should also clarify requirements for flares that control a mix of new and existing sources, such as where an affected facility installs a new pneumatic pump or compressor that is then routed to the same flare controlling other existing sources. The proposed regulatory text is not clear as to whether routing new sources to an existing flare would be authorized if the existing flare does not meet Subpart OOOOb monitoring requirements. To the extent that the Supplemental Proposed Rule expects midstream facilities to install new control devices for new affected facilities, EPA should understand that new control devices will create additional pollutant emissions. If the Supplemental Proposed Rule expects midstream facilities to modify existing control devices to accommodate both new and existing sources, then EPA should provide more time for compliance. Installing new flow meters, testing ports, or net heating value measurement tools on existing control device lines handling multiple units or sources involve "Hot Tap" safety protocols. This is specialized work that is typically handled by only a small handful of qualified contractors. In-house staff typically do not perform Hot Tap work. Therefore, if EPA expects an entire industry to modify existing flares, the compliance deadline must account for the relatively small labor pool available to perform that work.

GPA Midstream also requests clarification regarding flare testing requirements under proposed revisions to § 60.18(d). It is not clear if § 60.18(d) requires a formal test or some sort of certification that the flare meets applicable requirements. Nor is it clear whether all flares must meet a testing or certification requirement. If § 60.18(d) requires a formal test, GPA Midstream would like to ensure that adequate time for the necessary installation of ports to perform the flow and heating value requirements per the test methods in 60.18(d) on a live flare line.

GPA Midstream would also request confirmation that flares do not need to be continuously tested when they have a manufacturer's certification. We believe that EPA intended to exempt manufacturer-certified enclosed combustors from continuous testing, however, the regulatory text itself could be written to state that intent more directly. Accordingly, we ask that EPA clarify and confirm that manufacturer-certified control devices would only be required to meet the minimum and maximum flow requirements from the manufacturer to be compliant with Subpart OOOOb and Subpart OOOOc.

4. EPA Should Confirm That Carbon Regeneration Systems are Not Subject to Control Device Requirements

Some carbon absorption systems used in the midstream industry do not have access to a steam system, as frequently found at a chemical plant or refinery. In the gas production and processing industry, natural gas and heat exchange systems are used to regenerate the carbon beds instead of steam. These systems can be used when there is the potential for air to enter the system. A carbon bed does not have a direct fire source, limiting the potential for a fire in the system. The regeneration cycle is infrequent for these systems. GPA Midstream would like to confirm that the gas from these regeneration cycles would not be subject to any control requirements under the Supplemental Proposed Rule, if finalized.

5. Clarification Regarding Devices with Pressure Regulators

Because many flares and enclosed combustion devices rely on a pressure regulator, GPA Midstream would like to ensure that the emissions from any pilot, sweep, or purge gas required to prevent flame back flow will be exempt from any operating limit associated with control requirements. GPA Midstream believes that EPA intended such an exclusion while affected facility gas was not directly going to the flare. However, facilities may route affected gas to the fuel system which may end up at the flare as purge or pilot gas. Because many gathering and boosting facilities use field gas or waste gas as part of their fuel system to ensure these gases are not vented to atmosphere, GPA Midstream believes those streams should be exempted from the requirements while only these gases are going to the flare. This is important when pressure regulators are used on regulated streams to ensure flow minimums are met.

Further, GPA would like EPA to clarify and confirm that a pressure regulated flare does not need to meet the control requirements when using sweep and pilot gas. Sweep gas is needed to ensure the flare does not burn back into the stack and helps to prevent dead leg corrosion. Consistent with rules governing similar equipment at refineries,[23] EPA should likewise confirm that this practice is exempt from any operating restrictions in a final rule.

6. EPA Should Confirm the Scope of a Vapor Recovery Units as a Control Device

GPA Midstream requests that EPA confirm the scope of the use of Vapor Recovery Units as a control device, i.e., where the closed vent system ends and the fuel gas system begins. GPA Midstream believes that the closed vent system should be included up to the compressor unit as the fuel gas system can have a variety of different break points after it leaves the compressor and may not have another break point up to a heater or compressor. Once compressed, the gas is now at a higher pressure and should be considered recovered after it enters the recycle or fuel system.

[23] *See*, *e.g.*, 40 C.F.R. §§ 63.670(b) (pilot flame presence required only "when regulated material is routed to the flare"); 63.670(c) (visible emissions restriction only "when regulated material is routed to the flare"); 63.670(d) (flare tip velocity requirements apply "whenever regulated material is routed to the flare for at least 15 minutes.").

7. EPA Should Clarify Its Proposed "Leak Free Condition" Requirement

GPA Midstream would request that EPA clarify the meaning of ensuring "that each enclosed combustion control device is maintained in a leak free condition." *See* Proposed § 60.5413b(e)(7). GPA Midstream recognizes that the "leak free condition" requirement is not an entirely new concept, but owners and operators need additional clarity to ensure that inspections are completed properly to achieve compliance. GPA Midstream would submit this should be limited to checking for fugitive emissions on the line leading up to the enclosed combustion device, similar to the requirements on a closed vent system. However, if EPA intends to require other measures to demonstrate compliance with the "leak free condition" requirement, it should specify those and make those specifications available for review and public comment.

B. EPA Should Consider and Evaluate the Full Cost of Control Devices

GPA Midstream supports better monitoring for control device equipment but would like to ensure that any additional monitoring is done in a cost effective manner. GPA Midstream would also like to ensure that a proper cost-effective analysis is performed when considering control device requirements. As written, the Supplemental Proposed Rule would require the installation of thousands of flow meters, net heating value monitoring devices, and testing ports for compliance purposes. This monitoring equipment would cost the industry millions of dollars with costs expected to increase as short-term demand for this equipment dramatically increases as a result of the Supplemental Proposed Rule, and other rules, requiring similar monitoring equipment. We urge EPA to consider these costs fully before adopting any final rule.

1. EPA Should Consider the Additional Costs of Hot Tapping Flares

As discussed previously, installation of this equipment on existing flares will require a hot tap. This is specialized work that usually requires a third party contractor to perform. Because of the safety protocols that are required to perform this work, and the nature of the work, it is often a costly install. The cost of performing a hot tap will sometimes be as much as all of the other costs to install the equipment, depending on the location of the hot tap. These costs should be considered to assess the full costs of controls.

2. EPA Should Allow For More Flexibility in Flow Meters, as Requiring Flow Meters Accurate Up to 2% Maximum Flow Rates Unnecessarily Increases Costs

The purpose of the monitoring equipment that would be installed under the Supplemental Proposed Rule is to monitor general information on flares and ensure complete combustion. The equipment is not being used for complex calculations or controls that would be required by other rules such as MACT Subpart CC or the Ethylene MACT. The proposed Subpart OOOOb and OOOOc requirements would allow for a very large operating window under normal operations for most midstream control devices. Further, the midstream industry uses individual control devices for certain equipment, such as a device only for storage vessels. This means that many control devices see limited flow during a typical year.

The Supplemental Proposed Rule, however, would require that flow meters be accurate up to 2% at maximum flow rates. In most cases, such accuracy could only be achieved with an optical meter or an ultrasonic flow meter. These typically cost about $30,000 for basic models, however, there is no evidence in the record that, based on the Subpart OOOOb and OOOOc requirements, these precise and expensive flow meters will provide any benefits over less costly flow meters. As with many other types of flow meters, these also struggle with accuracy at lower flow rates such as when the device is only controlling breathing losses from tanks or pressure safety valve discharges at gas plants. As a result of these operating issues, even the most accurate flow meters will lose some accuracy. Accuracy at lower rates can increase with additional flow meter monitoring devices installed in tandem with the basic ultrasonic meter, however, this significantly increases the overall cost of this monitoring equipment. GPA Midstream would like to ensure that meters with an accuracy of up to 10% at maximum flows, such as thermal dispersion flow monitoring devices, can be used to show compliance with the proposed rule. Further, this accuracy should be warranted by the instrument provider.

C. EPA Must Consider Equipment Shortages in Providing an Adequate Lead Time for Compliance

GPA Midstream is also concerned about EPA providing enough lead time for installing the monitoring equipment required by the Supplemental Proposed Rule. This is complicated by potential supply chain issues that would be expected to arise as the entire industry orders thousands of new monitoring devices that would need to be installed over the next few years. This type of monitoring equipment has already started to see longer lead times as a result of global supply shortages. Further, the midstream industry is continuing to grow, meaning that more and more control devices are being installed every month, requiring the installation of more monitoring equipment. This does not include current demand for monitoring equipment from the production sector. Plant and compressor stations are currently being built without this monitoring equipment being part of the original plans because there was no reasonable way to anticipate these additional requirements. Therefore, they will require retrofits almost immediately. As a result, GPA Midstream would request at least one year to install the monitoring equipment for sources subject to Subpart OOOOb.

D. EPA Should Allow Alternatives to Demonstrating Compliance with Minimum Net Heating Value Requirements

Compressor station and gas processing plant waste streams generally have a net heating value that far exceeds the minimum values required under the Supplemental Proposed Rule. *See* 87 Fed. Reg. at 74,793.[24] Waste gas streams routed to control devices at midstream sources are largely comprised of natural gas and field gas, meaning that these streams are typically above 1,000 Btu/scf. Continuous monitoring requirements, and requirements to perform 10-day tests on control devices for storage tanks, pneumatic pumps, and compressor vents are unnecessary, imposing burdens and costs without any benefit. Instead, EPA should allow owners and operators to perform and maintain a design evaluation to ensure that waste gas streams will consistently

[24] GPA Midstream notes the exception of amine treater process vents, which tend to have a lower net heating value.

exceed minimum net heating value requirements. This would be similar to that provided in proposed § 60.5413b(c) for condensers and carbon absorption units, as well as for combustion device maximum flow rates in proposed § 60.5417b(d)(1)(viii)(D).

As an alternative, if a design evaluation is not sufficient, GPA Midstream proposes that a simplified sampling protocol be allowed for exempting a control device from continuous heat content monitored by allowing for samples to be taken twice a day for seven days. We believe that such sampling would demonstrate that streams have a relatively constant net heating value well exceeding the minimum requirements.

The Supplemental Proposed Rule would also require installation of net heating value equipment with a high-cost threshold for the expected emissions reductions. GPA Midstream asks that EPA ensure there is an allowance for monitoring options other than a calorimeter. The midstream industry has extensive experience using gas measurement and analytical tools as part of our fee-based business and believes that there are better tools available than a calorimeter. Options like gas chromatography and optical spectroscopy should be allowed for compliance purposes. Costs of this equipment can range from $75,000 to $100,000 each. For most control devices, the heating value of the gas would consistently be well above the 200 BTU/scf, or 300 BTU/scf, or 800 BTU/scf triggers, making this equipment very expensive for the expected heat content of the gas streams. As currently written, the Supplemental Proposed Rule's exemption option to the expensive and unnecessary continuous monitoring requirement would require extremely expensive short-term monitoring to obtain 240 samples and lab analyses, as well as specialized contractors to install and operate those monitors, to exempt a site from the heat content monitoring. With hourly samples taken over a ten day period, each sampling event would cost approximately $200,000 per control device due to equipment rental costs and the costs for contractors to be onsite analyzing the data during this period. This issue becomes more complicated when the facility is at a remote location where staff is not there to continuously catch samples or support the testing company analyzing the sample.

E. <u>Flow Rate Monitoring is Problematic</u>

GPA Midstream is concerned that the Supplemental Proposed Rule's flowrate monitoring requirements present significant technical difficulties and, in some cases, may not be possible. Many of these systems operate at, or slightly higher than, atmospheric pressure, meaning that only small volumes of gas will be sporadically released. These systems are not designed to provide three hours of continuous flow to the control device. Manufacturer tested emission control devices provide an inlet pressure requirement, which thereby mandates installation of a control valve and pressure monitoring. This as well as improved liquids handling leads to intermittent vapor routing making traditional performance testing, which consists of three one-hour runs, very difficult to complete. For example, a GPA Midstream member company compiled one month's worth of data on pressure actuating at a tank facility. The valve routing vapors to enclosed combustion device opened for an average of eight seconds per actuation. The total time that vapors were routed to the control device during a day was under seven minutes.

EPA should allow for the use of pressure monitors coupled with control valves in lieu of flow rate monitoring because pressure monitoring achieves the same goal- ensuring that a sufficient volume of waste gas is going to the control device to ensure proper combustion. Many of the tank facilities that would be covered by the control requirements are already controlled by pressure monitors and control valves that route vapors to the control device only when tank pressure meets the manufacturer's set point for complete combustion and the safety setpoints on the tank pressure relief devices. For example, if a tank is rated to hold a pressure of 16 ounces, then a pressure transducer will open and allow vapors to the control device when the pressure reaches 10 ounces. It will close when pressure drops to seven ounces. Certain manufactures state that only one ounce of pressure is needed to achieve good combustion, making pressure monitoring an accurate and reliable alternative to flow rate monitors.

F. Temperature During Control Device Testing is the Best Indicator of Combustion Performance and Should be an Available Alternative to Continuous Monitoring

GPA Midstream proposes that temperature monitoring not be based on just a static number but on the temperature achieved during the initial performance testing that demonstrates required destruction efficiency set as a minimum temperature limit. The minimum temperature could be updated in subsequent performance tests if the required destruction efficiency can be met at a lower temperature. The temperature limit in proposed § 60.5414b(c) is unnecessarily high and would require a large amount of supplemental fuel gas to maintain continuous compliance with the limit generating additional greenhouse gas emissions from the combustion of supplemental fuel. Further, the proposed limit appears to be based on a temperature in the flame zone which many enclosed combustors cannot monitor. Most enclosed combustors have thermocouples installed above the flame zone in the combustion chamber, resulting in lower read temperatures due to the location. If the thermocouple is used during testing, however, the test should demonstrate that proper combustion is occurring. Therefore, GPA Midstream asks that EPA provide more flexibility in temperature testing to account for the differences inherent in enclosed combustor design.

G. EPA Should Maintain the Enclosed Combustor Concentration Limit

GPA Midstream would like to ensure the concentration limit for existing enclosed combustors should continue to be allowed as included in OOOOa. Destruction efficiency testing requires VOC sampling at the inlet and outlet of the control device. Many existing control devices do not have an inlet sampling port. Combined with the potential need to install additional monitoring equipment, allowing the use of a 20 ppm concentration limit will allow facilities that do not have intlet testing ports to have an alternative to meet compliance requirements for both Subparts OOOOb and OOOOc.

H. EPA Should Consider the Technical Difficulties in Testing Existing Storage Vessel Control Devices

GPA Midstream wants to ensure that EPA understands and considers technical difficulties in testing existing storage vessel controls. As discussed above, many of the closed vent systems do not have testing ports to accommodate monitoring. These existing systems have also never required certification by a qualified individual or professional engineer regarding maximum or minimum instantaneous flow rates. Further, testing these systems would involve significant technical difficulties as tank systems do not typically provide a high volume, continuous flow, and even where flow may be at high volumes, those periods tend to be sporadic, rare, and for very brief periods of time. EPA must clarify how control device testing at maximum flow rate over the required three-hour period should be accomplished for storage vessels. GPA Midstream members are not aware of how to easily simulate storage vessel vapor composition for a continuous three-hour period.

I. EPA Should Allow for FTIR Testing as an Alternative to Method 25a

Finally, GPA Midstream requests that EPA allow owners and operators to use Fourier Transform Infrared ("FTIR") spectroscopy as an alternative to Method 25a. *See* Proposed § 60.5413b(b)(3). FTIR testing is commonly used for engines and turbines, and EPA previously approved the method for demonstrating compliance with 40 C.F.R., Part 60, Subparts IIII, JJJJ and KKKK and Part 63 Subpart ZZZZ. This is a more cost-effective testing method than Method 25a, because it can measure multiple pollutants at once with the same monitor, reducing mobilization costs. Accordingly, EPA should authorize FTIR testing as an option for owners and operators.

VII. EPA Should Revise Proposed Regulations Governing Reciprocating Compressors to Ensure Appropriate Flexibility and Provide Additional Clarity

GPA Midstream supports aspects of the proposed regulation provided in the Supplemental Proposed Rule, but urges EPA to make important changes to any final rule to ensure appropriate flexibility and provide additional clarity. As described in more detail below, GPA Midstream believes that allowing owners and operators to combine emissions across compressor cylinders, and implementing work practice standards, such as instituting a repair or replacement scheme, and allowing owners and operators to route rod packing emissions to a control device would alleviate the significant technical difficulties involved in the proposed requirements. Further, we ask that EPA resolve conflicting language in the proposed regulatory text regarding compliance dates and to provide further consideration of the technical challenges and costs involved in implementing the proposed regulations.

A. The Reciprocating Compressor Rod Packing Requirements Should be Considered a Work Practice Standard Instead of an Emission Standard

GPA Midstream submits that rod packing vent compliance must be regulated as a work practice instead of as a numeric emission standard. Unlike with stack-related emission sources subject to control devices, rod packing emissions result from equipment that deteriorates from normal use. Similar to the LDAR program, owners and operators would have to monitor the rod packing to determine if fugitive emissions have reached a threshold level and, if the threshold is reached, repair or replace the rod packing. 87 Fed. Reg. at 74,717. Such a situation accords with the statute's determination of when using a work practice standard is appropriate: where "a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant." 42 U.S.C. § 7411(h)(2).

As an emission standard, the proposed rod packing requirements are unworkable. Operators would be forced to decide between continuing to operate out of compliance until a maintenance shutdown can be scheduled or shutting down the compressor immediately to conduct the repair and venting or flaring gas that can no longer be compressed and transported during the unscheduled shutdown. A forced shutdown will likely result in significantly more emissions than continuing to operate until the next scheduled maintenance shutdown. For systems that are at capacity, shifting the incoming gas to another station is not a feasible or reliable option, resulting in additional flaring and venting, which is magnified given the time it takes to have producers shut-in wells.

Thus, the risks of additional emissions from an emissions standard significantly outweighs any purported benefits and support relying on a well-established work practice standard for rod packing vent emission control. Under a work practice framework, companies would be required to complete a corrective action within 720 hours of operation (equivalent to 30 days) and allow for delay of repair, similar to leak monitoring programs, of up to two years if repair goes beyond the replacement of rod packing. See separate comments below on delay of repair. Exceeding the vent rate threshold after the time for corrective action would be a deviation, but exceeding the vent rate within the time allotted to correct would not. Additionally, under either standard, companies that choose to replace rod packing annually (prior to 8,760 hours) should not be required to perform monitoring.

B. EPA Should Clarify That the Leak Rate is on a Per Rod Packing Vent Basis

GPA Midstream supports the Supplemental Proposed Rule's proposal to perform volumetric flow rate monitoring after 8,760 hours instead of performing such monitoring every calendar year. 87 Fed. Reg. at 74,797. However, GPA Midstream believes that it is important to allow reciprocating compressor owners and operators the option of using a combined emissions leak rate, based on the number of cylinders routed to a common vent stack, in meeting the 2 scfm per cylinder threshold. As explained in GPA Midstream's January 2022 comments, combining is appropriate because a single reciprocating compressor may have multiple cylinders (also referred to as compression cylinders, throws, or packing case vents) routed to a common vent stack, making rod packing-specific measurements impractical and unreasonable. *See* Exh. A at 30. Such a combining option, if included in proposed Section 60.5385b(a), would read as:

> § 60.5385b(a). The volumetric flow rate, measured in accordance with paragraphs (b) **or (c)** of this section, must not exceed 2 standard cubic feet per minute (scfm) **per cylinder, or a combined rod packing emission flow rate greater than the number of compression cylinders multiplied by 2 scfm**. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

Including a combined emission total provision and specifying 2 scfm per cylinder, such as the one described above, would be similar to that allowed under California law. *See* 17 CCR § 95668(c)(4)(D) (allowing for "a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm").

C. EPA Should Include a Repair or Replacement Timeframe and a Delay of Repair Provision

GPA Midstream requests that EPA include a timeframe to replace or repair rod packing that exceeds the volumetric flow rate specified in §60.5385b(a). As currently written, it is not clear how compliance will be managed if the volumetric flow rate indicates that a compressor cylinder exceeds the 2 scfm standard. Adding a timeline to repair or replace the cylinder would be consistent with EPA fugitive monitoring programs and California regulations governing rod packing emissions. Those regulations state that a "compressor with a rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute (scfm), or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be successfully repaired within 30 calendar days from the date of the initial emission flow rate measurement." 17 CCR § 95668(c)(4)(D). However, instead of providing 30 days to replace or repair the compressor cylinder, GPA Midstream believes that requiring replacement or repair within 720 operating hours would be more consistent with the hours of operation limitations in proposed Sections 60.5385b(a)(1) and (2).

GPA Midstream also requests an appropriate delay of repair option due to potential issues with obtaining necessary parts or equipment in the time required to make repairs or where weather makes compressors in remote areas inaccessible. This would be consistent with multiple federal fugitive monitoring programs and California regulations. *See also* 87 Fed. Reg. at 74,798 (acknowledging the need for a delay of repair option for "scenarios beyond the owner or operator's control"). Thus, a delay of repair option is a commonly used and well understood compliance option for certain scenarios. GPA Midstream requests a two year delay of repair timeline that matches the leak monitoring program for streamlining. Additionally, the time to repair rod packing has all similar repair timing constraints as fugitive components.

D. EPA Should Allow for Rod Packing Vents to be Routed to a Control Device

GPA Midstream recommends that EPA continue to allow an option for rod packing vents to be routed to a control device. It may not always be technically feasible to route rod packing vents back to the process, and this will be especially true for existing sources. Specifically, in many cases rod packing capture to process will require recompression and, depending on the location of the facility, may require a gas driven engine to achieve recompression. The engine's emissions could offset many of the emissions reductions the Supplemental Proposed Rule would purportedly achieve and such an offsetting increase in emissions from this requirement should be considered by EPA before finalizing any rule. Additionally, routing rod packing vents back to the process could introduce oxygen into the system, leading to safety concerns.

In addition, depending on the pressure differential between nearly ambient rod packing vents and pressurized piping, substantial horsepower may be required to achieve capture. The currently available rod packing capture systems that have been attempted by GPA Midstream members have not performed as intended and, in some applications, have not worked at all. Even if these systems were as effective as advertised, timing is a significant concern as the supply is not currently available to meet demand. Delay is further exacerbated by the need for engineering work. Capture to a process is not always straightforward and will require time for existing or modified facility redesign, as well as for new facilities, assuming effective re-design is feasible. For instance, gas quality in the rod packing vents may not be compatible with the only technically feasible location in the process for the gas to be routed. Moreover, pressure differentials may be incompatible or sour gas from the rod packing vents could only be routed to the fuel gas system, but sour gas is often a poor candidate for fuel gas.

Due to the technical difficulties that can arise, GPA Midstream requests that EPA allow an option to route rod packing vents to a control device for new, modified and existing facilities. If permitted, GPA Midstream also recommends that, where rod packing vents are routed to a control device, they should be flow measured every 26,000 hours of operation. This will ensure that rod packing is appropriately maintained while overall emissions are greatly reduced.

E. Certain Conflicting Compliance Deadlines Require Clarification

GPA Midstream is concerned that portions of the proposed regulatory text include compliance dates that are inconsistent with other portions of the text that they cross-reference. We urge EPA to resolve these conflicting dates before issuing any final rule.

Proposed § 60.5370b(a)(1)(i) requires compliance with § 60.5385b(a)(1) on or before 12 months after publication of the final rule or 12 months after the source's initial startup, whichever is later. This is inconsistent with proposed § 60.5385b(a)(1) which requires owners and operators to "conduct your first volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after" the final rule publication date "or on or before 8,760 hours of operation after startup, whichever is later." (emphasis added) EPA should clarify that the compliance timeline referenced in proposed § 60.5370b(a)(1)(i) should be on or before 8,760 hours of operation after either the final rule publication date or the startup date, whichever is appropriate.

Proposed § 60.5370b(a)(1)(ii) requires compliance with proposed § 60.5385b(a)(2) within 30 days after compliance with proposed § 60.5385b(a)(1) (referenced above). This 30 day compliance date, however, is inconsistent with proposed § 60.5385b(a)(2). That requires owners and operators to "conduct subsequent volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 2 scfm volumetric flow rate." EPA should clarify that the compliance date referenced in proposed § 60.5370b(a)(1)(ii) should be 8,760 hours of operation, as identified in proposed § 60.5385b(a)(2).

Proposed § 60.5370b(a)(1)(iii) requires compliance with proposed § 60.5385b(a)(3) upon initial startup. However, there is no § 60.5370b(a)(3) in the proposed regulatory text. EPA should clarify whether § 60.5370b(a)(3) is missing or if proposed §60.5370b(a)(1)(iii) should be deleted. This would impact §60.5370b(a)(1) as well, which requires compliance with § 60.5370b(a)(1)(iii). If proposed § 60.5370b(a)(1)(iii) is deleted, that should be noted in proposed § 60.5370b(a)(1) by deleting the reference.

Finally, proposed § 60.5415b(g) requires that reciprocating compressors complying with proposed § 60.5385b(d) must demonstrate continuous compliance with §§ 60.5415b(g)(4) through (g)(6). However, there is no (g)(5) or (g)(6) in the proposed regulatory text. EPA needs to clarify if (g)(5) and (g)(6) are real requirements that are missing from the regulatory text or if the text should be changed to only list (g)(4).

F. High-Volume Samplers Should be Calibrated According to Manufacturer Specifications

GPA Midstream suggests that EPA's detailed calibration requirements for high-volume samplers be removed and replaced with a more general requirement that samplers be calibrated in accordance with the manufacturer's specifications. Daily field calibration of methane concentrations and volumetric flow rate vary by manufacturer such that one set of calibration instructions is not appropriate for all high-volume samplers and should not be subject to a universal rule or standard.

G. Proposed Rules for Reciprocating Compressors Need to Consider the Full Costs and Technical Challenges With Retrofitting Monitoring Ports

Lastly, the proposed EG and NSPS fails to adequately consider the costs and technical challenges associated with retrofitting each existing reciprocating compressor cylinder for monitoring ports. As described above, each cylinder does not have its own vent. There would need to be alterations made to the piping to allow for monitoring to be conducted on a per-cylinder basis. The costs required to add new piping so each cylinder has its own vent and install monitoring ports have not been considered. Should EPA choose to move forward with a proposed rule, EPA should issue guidelines allowing a phased approach to adequately account for port installation.

VIII. EPA Should Defer or Adjust Proposed Standards for Dry and Wet Seal Centrifugal Compressors

A. EPA Should Defer Proposed Standards for Dry Seal Centrifugal Compressors Until it Obtains Additional Data From Subpart W Reporting

The Supplemental Proposed Rule's proposed emission threshold of 3 scfm for dry seal compressors is overly stringent and is not supported by the record. Specifically, the emission threshold appears to be based on a severely limited number of outdated dry seal measurements. This data is referenced in EPA's Natural Gas Star report, "Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors" (2006), and in Annex Tables 3.6-2 and 3.6-6 supporting EPA's, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020." This underlying data dates back to 1996 (EPA/GRI study[25]) with few studies being performed since 2000. EPA should not rely on such stale data to establish an emission threshold as it is neither accurate nor representative of dry seal centrifugal compressors. GPA Midstream recommends that EPA postpone establishing any type of quantitative threshold for dry seal centrifugal compressors until after it finalizes amendments to the Subpart W reporting rule. *See* 87 Fed. Reg. 36,920 (June 21, 2022) (proposed rule). Once implemented, EPA will have thousands of data points to give a

[25] Methane Emissions From the Natural Gas Industry, Volume 2: Technical Report EPA-600 /R-96-C80b (June 1996).

more accurate dry seal centrifugal compressor measurements that can be used for a subsequent emissions threshold.

Although GPA Midstream believes that EPA should wait for more accurate data, if it is intent on establishing a dry seal emissions threshold before receiving the Subpart W reports, GPA Midstream recommends relying upon the manufacturer's specified maximum leak rate for a particular unit. A recent review of dry seal leak curves from a major supplier of centrifugal compressors to the natural gas industry indicates that dry seal leakage rates can vary from 2 to 20 scfm per compressor (with 2 seals per compressor), depending on the make, model, and operating suction pressure of the compressor.[26] If EPA wishes to set one threshold applicable to *all* dry seal centrifugal compressors within the next year, GPA Midstream recommends that EPA set the threshold at 10 scfm per primary dry seal in order to allow for sufficient variability among existing dry seal leak rates.

Further, GPA Midstream recommends that dry seal centrifugal compressors be regulated through work practice standards. Under a work practice framework, companies would be required to complete a corrective action within two years if emissions exceeded the allowable threshold per primary dry seal. These corrective actions could include: (1) repair or replacement of the dry seal; (2) routing emissions to a control device from the covered dry seal gas tank through a closed vent system; or (3) routing emissions to a process from the primary dry seal vent through a closed vent system. If the dry seal compressor is routed to a process, then EPA should clearly state in any final rule that volumetric flow rate monitoring is not required.[27] If the corrective action cannot be completed within two years, then a corrective action plan with work scope and alternate schedule would be submitted to EPA. Exceedance of the emissions threshold after two years, or after the time stated in the corrective action plan, would result in a deviation. This is consistent with delay of repair requirements under Section 60.5397a(h)(3), requiring repair within two years, or the next scheduled shutdown (whichever is earlier) where repairs are technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair. GPA Midstream asks that the same standard for Subpart OOOOb be applied here.

B. EPA Should Adjust Proposed Standards for Self-Contained Wet Seal Centrifugal Compressors

GPA Midstream supports EPA's development of a new "self-contained wet seal centrifugal compressor" category, since this type of compressor emits less methane compared to conventional wet seal centrifugal compressors. However, we also recommend to changes to the Supplemental Proposed Rule's approach to regulating these compressors.

[26] Solar Turbines, *Emissions from Centrifugal Compressor Dry Gas Seal System*, PIL 251 Revision 1 (May 22, 2020).

[27] If the dry seal compressor is routed to a control device, then it would be appropriate in a final rule to require volumetric flow rate monitoring once every 3 years. Recordkeeping and reporting requirements should be equivalent to those currently in place for conventional wet seal compressors. If the dry seal compressor is routed to a process, then EPA should clearly state that volumetric flow rate monitoring is not required.

First, GPA Midstream recommends that § 60.5380b(4)(i) be revised so that the volumetric flow rate not exceed three SCFM per primary seal. This would be in line with California regulations for wet seal compressors, which apply the same 3 scfm limit but on a per seal basis. *See* 17 CCR § 95668 ("A compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired"). Based on actual annual measurements collected by GPA Midstream member companies under EPA's GHG Reporting Program, a 3 scfm per seal threshold is an effective indicator of a worn or damaged seal, or a malfunctioning internal wet seal gas recovery system.

Second, GPA Midstream recommends that self-contained wet seal compressors be regulated through work practice standards, similar to our recommendations with respect dry seal centrifugal compressors. Under that framework, where emissions exceed the 3 scfm per wet seal threshold, owners or operators would complete a corrective action within two years. These could include: (1) repair or replacement of the seal and / or internal seal gas recovery system; (2) routing emissions to a control device from the degassing vent through a closed vent system; or (3) routing emissions to a process from the degassing vent through a closed vent system. Exceedance of the emissions threshold after two years, or after the time stated in the corrective action plan, would result in a deviation.

Third, GPA Midstream suggests that EPA's detailed calibration requirements for high-volume samplers, in proposed Section 60.5386b(c)(5)(i)(B), use a more general requirement that samplers be calibrated in accordance with the manufacturer's specifications. Daily field calibration of methane concentrations and volumetric flow rate vary by manufacturer such that one set of calibration instructions is not appropriate for all high-volume samplers and should not be subject to a universal rule or standard.

Lastly, GPA Midstream seeks clarification on what industrial segments are included, and what industrial segments are excluded, under EPA's definition of "centrifugal compressor affected facility" at proposed Section 60.5365b(2)(b).

IX. EPA Should Revise the Compressor Station LDAR / Closed Vent System / Alternative Monitoring Provisions to Provide Greater Flexibility and Reflect Practicalities of Operations and Monitoring Development

A. EPA Should Continue to Exclude Devices Intended to Vent From the Definition of "Fugitive Emissions Component"

GPA Midstream submits that EPA should not adopt a revised definition of "fugitive emissions component," *see* proposed § 60.5430b and § 60.5430c, as the revisions could present substantial confusion and potentially unduly broaden the scope of fugitive emissions to include emissions from equipment designed as part of the process to vent emissions. We urge EPA not to make this revision.

The current definition states: "Devices that vent as part of normal operation, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions." 40 C.F.R. § 60.5430a. The current definition thus makes a logical and critical distinction between fugitive emissions that arise from operating equipment and process emissions that vented from a stack as part of normal operations.

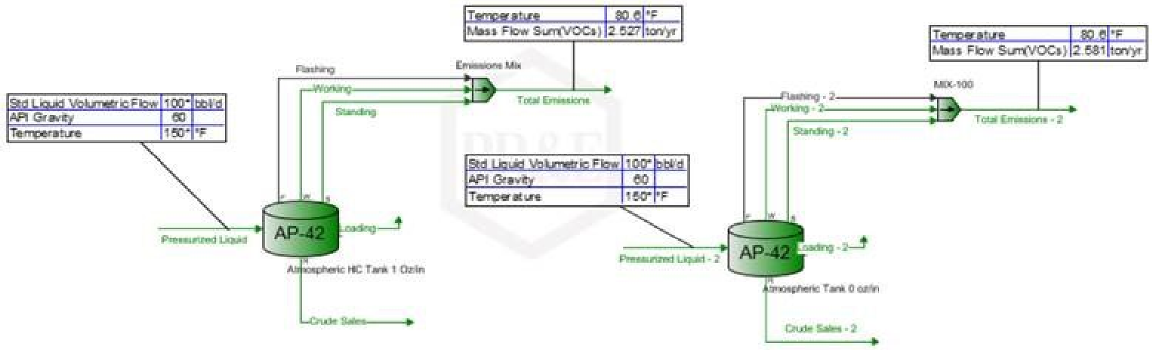
In the supplemental proposal, EPA would remove the quoted language from the current definition above. This would create significant confusion and compliance uncertainty by potentially seeking to regulate equipment as "fugitive emissions components" that do not have fugitive emissions. EPA provided no rationale for altering the longstanding definition and did not either acknowledge the revision or the change in interpretation that appears to significantly expand the types of equipment considered to be "fugitive emissions components."[28] Any final rule should restore the language discussed above to the definition of "fugitive emissions components."

B. EPA Should Restore the Word "Controlled" to the Definition of "Fugitive Emissions Component"

In addition, EPA deleted the word "controlled" from the definition of "fugitive emission component" without any explanation. The definition under 40 C.F.R. § 60.5430a currently includes "thief hatches or other openings on a **controlled** storage vessel not subject to § 60.5395 or § 60.5395a." Fugitive emissions from thief hatches or openings on uncontrolled tanks are expected as the tank breathes in and out through these vents to prevent the tank from rupturing. EPA should acknowledge that the vents on uncontrolled tanks are expected to vent and should not be considered fugitive emissions.

GPA Midstream recognizes that even uncontrolled, atmospheric tanks are operated under a slight amount of pressure, often at approximately one ounce. GPA Midstream ran a generic process simulation in ProMax comparing uncontrolled tanks with one ounce of pressure and uncontrolled tanks with zero pressure. Assuming all other inputs are the same, the total tank emissions were nearly identical with only a two percent difference (2.53 tons per year vs. 2.58 tons per year).

[28] Despite changing the definition of "fugitive emission components" to include thief hatches and other openings, EPA's Technical Support Document does not account for them. It expressly states that the "analyses for fugitive emissions from compressor stations included in the November 2021 proposed TSD has not changed." EPA, Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emission Guidelines (EG), EPA-HQ-OAR-2021-0317-1578 (Oct. 2022) ("TSD") at 5-1.



The Technical Support Document's discussion of model production facility plants further supports GPA Midstream's position. That discussion states that "Model Plant 3 contains tanks, but as they are uncontrolled, the emissions from these tanks are allowed to vent to the atmosphere. Controlled tanks in Model Plant 4 must be vented through a closed system to a control device. Here, an open thief hatch or leak in the closed vent system could require action to repair the leak." Coburn-Strott Memo at 14. The TSD's Table 1 showed zero tanks for Model Plant 3 because there are zero controlled tanks.

Table 1. Model Production Sites.

Model Site Name	Description	Number of Fugitive Equipment Components	Number of Tanks	Number of Large-Emitters
Model Plant 1	Single wellhead only	112	0	1
Model Plant 2	Dual wellheads only	220	0	1
Model Plant 3	Typical production site; uncontrolled tanks	612	0	2
Model Plant 4	Typical production site; controlled tanks	612	4	2

This, along with the discussion noted above and the TSD's failure to account for the additional costs that midstream facilities would occur monitoring and potentially repairing uncontrolled tanks indicates that EPA failed to realize the importance of the definitional change, the proposal has made the change without providing any explanation. Conversely, if EPA intended to require leak detection monitoring for components that are no longer part of a closed vent system, then the agency must explain the rationale for this regulation and define the benefit EPA claims this could possibly yield. Otherwise, GPA Midstream requests that EPA expressly state that it will apply the definition of "fugitive emission component" currently found in 40 C.F.R. § 60.5430a to Subparts OOOOb and OOOOc.

C. EPA Should Provide 180 Days for Initial Compliance Monitoring

GPA Midstream proposes that EPA provide 180 days to conduct the initial fugitive emissions monitoring for affected facilities under proposed § 60.5397b. Conducting compliance monitoring is a lengthy process requiring the development, coordination, and scheduling of internal and contracted services. Often, these monitoring services must be planned and scheduled more than 90 days in advance. Here, affected facilities and service contractors must first develop and update required systems and plans under proposed §§ 60.5397b(b)-(d) for newly affected facilities. Then they – along with the rest of the industry – must attempt to schedule contractors for the initial fugitive emissions monitoring. EPA should accept the initial fugitive monitoring results performed in accordance with Subpart OOOOa for sites constructed after the applicability date of Subpart OOOOb as those sites had to meet Subpart OOOOa requirements until Subpart OOOOb was finalized. Further, the fugitive monitoring requirements under both subparts are effectively the same.

D. EPA Should Allow 30 Days After an AVO Inspection to Attempt a First Repair

Proposed § 60.5797b(h)(2) requires a first attempt at repair for any leaking fugitive emission components detected through audible, visual, or olfactory ("AVO") inspection within 15 days of discovery. EPA does not explain why it would provide half as much time for a first attempt at repair of leaking fugitive emission components detected by AVO, as opposed to leaks detected by other means. For instance, when a leaking component is detected through Method 21 or OGI inspections, owners and operators must complete a repair within 30 days. Proposed § 60.5398b(b)(4)(iii). There is no obvious reason why the detection method could impact the time required to order parts and make the repair, for which at least 30 days is essential in today's economy (with continuing supply chain challenges) and with the expected increased demand associated with the new regulations. Should EPA finalize the rule, it should allow for 30 days to attempt a first repair of any leaking component detected through an AVO inspection. EPA should not be concerned about the repair being outstanding during the next scheduled AVO inspection. When moving to a frequency like monthly, it is unreasonable for EPA to assume there will not be overlap in surveys and repairs.

E. The Periodic Screening Option Should be Revised

The proposed regulatory text offers the option of periodic screening, but if a leak is detected, the owner/operator would be required to conduct a full survey of <u>every</u> fugitive emission component. *See* Proposed § 60.5398b(b)(4)(ii)(4). This would practically be the same monitoring requirement found in proposed § 60.5397b. Thus, the periodic screening option not only provides no real benefit over quarterly monitoring with an annual OGI inspection, but it adds the cost of periodic screening – which would be a significant additional cost, where an owner or operator must also conduct bi-monthly or monthly screening. To make the periodic screening option meaningful, GPA Midstream proposes that, for owners or operators that choose the periodic screening option, follow-up inspections be focused on the identified source of the leak instead of the entire facility.

F. EPA Should Not Refer to Leak Investigations as a "Root Cause Analysis"

As proposed, §§ 60.5398b(b)(4)(iv) and 60.5398b(b)(5) would require owners or operators to complete a "root cause analysis" in five days, whenever a leak is detected from a control device failure or closed vent system cover. EPA does not define what is meant by a "root cause analysis" or what documentation it expects such an analysis to produce. As discussed in more detail below, a root cause analysis involves a formal systematic investigation, using multiple potential methodologies, into the potential causes of an incident that identifies corrective actions to reduce the probability of similar future incidents. *See* Section VII, *infra* (discussing root cause analysis requirement for the super-emitter program). Root cause analyses typically involve several specialized team members and take far longer than the five days specified in the proposed regulatory text. EPA has not considered the costs or the time required to perform a formal root cause analysis. GPA Midstream recommends that EPA use a more generic and appropriate term, such as "evaluation," in describing the examination and determination described in the proposed regulatory text. Even as to an evaluation, EPA should allow a minimum of 30 days to make the necessary assessment. If a "root cause analysis" is retained, EPA should allow at least 90 days to complete that more formal and complex analysis.

G. EPA Should Exclude Welded Pipe Seams From AVO Inspections

Under proposed § 60.5416b(a)(1), the Proposed Supplemental Rule would require annual AVO inspections of welded pipe seams on closed vent systems. EPA should exclude welded pipe seams from inspections. Subpart VVa has never included welded seams as fugitive emission components, and for good reason. Once welded, these seams must meet all pressure and leak tests associated with the original pipe and are, in fact, structurally similar to the pipe. Further, inspecting them presents practical difficulties as welded sections are not tracked on P&IDs or any other inventory. Owners and operators would have to undertake an unusually time-consuming and burdensome survey of all pipe welds in the facility. This should not be necessary. The Supplemental Proposed Rule provides no rationale for requiring weld inspections, such as claims that these welds leak in any way. Absent a rational basis for imposing such a requirement, EPA should exclude welded pipe seams from AVO inspections.

H. Typographical Errors

Proposed § 60.5398b(c)(1)(i) states that the "sensitivity of the system must be such that it can at least measure an order of magnitude less than the action-level defined in paragraph (c)(4)(iii) of this section." The proposed regulatory text does not contain a § 60.5398b(c)(4)(iii).

Proposed § 60.5398b(d) contains a link to EPA's Emission Measurement Center webpage (https://www.epa.gov/emc/oil-andgas-approvedalternative-test-methods). This link does not work.

Finally, several sections of the proposed rule require differing accuracy, with some requiring four decimals of a degree, *see*, *e.g.*, proposed § 60.5398b(c)(2)(i) and others to five decimals of a degree. *See* proposed § 60.5398b(b)(1)(i). Whether EPA intended to require four decimals or five decimals, it should correct those that are inconsistent.

X. EPA Should Revise Gas Plant LDAR and Appendix K to Provide for a More Reasonable Monitoring Framework

A. The Absence of a Methane or VOC Threshold Would Make Leak Detection and Repair Unnecessarily Burdensome Without a Corresponding Benefit

As GPA Midstream explained in its prior comments, EPA should retain the "in VOC service" requirement and 10% VOC by weight threshold, as well as establish a similar 1% threshold for equipment in methane service. Exh. A at 35-36. However, the proposed regulatory language accompanying the Supplemental Proposed Rule imposes no threshold for either VOCs or methane for leak detection monitoring purposes, asserting that "[e]ach piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates" otherwise. Proposed Section 60.5400b(a)(2). EPA should reconsider what is effectively a proposed zero threshold standard for both VOCs and methane.

Gas plants contain many streams, such as acid gas, wastewater, and recycled water, where VOCs and methane are present but so low that they would not be detected by flame ionization detectors (FIDs). GPA has attached several redacted examples of natural gas processing plant streams that contain little VOC or methane content.[29] Yet, because the VOC or methane content of these streams are not zero, and presumably have a theoretical potential to emit, owners and operators would waste substantial resources to conduct LDAR monitoring on components that will always result in non-detects. The Supplemental Proposed Rule offered no actual data to the contrary. Thus, the proposed regulatory language would wastefully impose costs and burdens on owners and operators with no potential benefit. GPA Midstream reiterates that a 10% VOC threshold, along with a 1% methane content threshold, is appropriate in determining which streams should be subject to an LDAR program and that such threshold requirements are consistent with EPA's longstanding practice.

B. The Supplemental Proposed Rule Provides no Basis to Increase Monitoring for Closed Vent Systems

EPA would require initial and bi-monthly optical gas imaging inspections in accordance with proposed Appendix K for closed vent systems and covers at onshore natural gas processing plants or, as an alternative, quarterly Method 21 monitoring to ensure there are no detectable emissions. EPA, however, has provided no rationale for either increasing closed vent system monitoring frequencies from the current initial Method 21 monitoring and annual AVO inspections under Subpart VVa or requiring optical gas imaging inspections instead of Method 21 monitoring. Closed vent systems have extremely low leak rates, larging owing to the small number of components and the lack of constantly moving parts, such as valves. Hard piping or duct work will not suffer the type of deterioration, and potential leaks, as moving parts that endure friction. EPA should either withdraw this proposed requirement or provide some explanation regarding the basis for increasing monitoring frequency, including a description of what environmental benefit could be expected by more frequent monitoring of equipment that rarely leak.

[29] See Exhibit C (data from acid gas sample), Exhibit D (amine still gas sample).

C. EPA Should Further Revise Appendix K

GPA Midstream's January 2022 comments raised numerous concerns with Proposed Appendix K. *See* Exh. A at 33-41. We incorporate those comments by reference, as EPA does not appear to have addressed those comments in the Supplemental Proposed Rule. Here, GPA Midstream wishes to emphasize several issues that must be addressed in any final rule: dwell times, survey breaks, the operating envelope, and senior camera operator requirements. As GPA Midstream previously discussed in its January 2022 comments, the changes to OGI monitoring protocols in Appendix K would impose introduce significant disincentives to using OGI monitoring for natural gas plants and compressor stations. *See* Exh. A at 36. These include increased time due to minimum universal dwell times and break requirements and the need to perform surveys six times per year. This not only reduces the incentive for owners and operators to move away from Method 21 but, as noted in our January 2022 comments, EPA still has not provided any reasoned basis for the dramatic changes to how OGI monitoring would be performed.

1. Appendix K Discourages OGI Camera Use

The midstream industry and EPA share the goal of advancing the use of emerging technologies because they offer the possibility of being accurate and more efficient tools. The midstream industry views OGI as a valuable tool, however, Appendix K is drafted in a way that would discourage its use over Method 21 monitoring at gas plants. For instance, Section 9.3.2 would require expending significant time and effort to "develop visual cues (*e.g.*, tags, streamers, or color-coded pipes) to ensure that all regulated components were monitored." Establishing a new set of component tags throughout gas plants (and keeping them updated over time) offers no advantage over Method 21 and discourages OGI camera use. Further, as described below, Appendix K approach is overly rigid with respect to everything from dwell times to break times, robbing it of any improved efficiencies over Method 21.

2. EPA Should not Dictate a Uniform OGI Dwell Time

GPA Midstream appreciates that the Supplemental Proposed Rule reduced the dwell time per angle from five seconds to two seconds, 87 Fed. Reg. at 74,839, which appears to address the Proposed Rule's inconsistent description of minimum dwell times. *See* Exh. A at 39. However, we believe that the concept of establishing a minimum dwell time is still too restrictive and does not take full advantage of the equipment's ability to make OGI the preferred option at a gas plant. A two second dwell time does not allow for a camera operator's experience to come into play. The only study on operator ability and dwell time that GPA Midstream is aware of is Zimmerele, *et al.*, Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions, *Environ. Sci. Technol*. 2020, 54 (18), 11506-11514. In that study, a scan speed is observed on the unit level (well head, separator, tank) and not on the individual component level. Each unit could have a varying number of components, as defined in Appendix K. Zimmerele, *et al.* (2020) recommends a greater than three minute per inspection time on a per unit basis, not a dwell time on an individual component basis.

Appendix K should leave judgments regarding dwell times to the experienced camera operator. This is particularly true when groups of equipment are viewed as this does not lend itself to a rigid dwell time. Gas plants will have very similar component groupings at common process units and operator experience with how to view these groupings, including the time required, will develop quickly. One of the current advantages of using OGI cameras under Subpart OOOOa is that individual component counts are not necessary. Under Appendix K, however, a component-driven time requirement that disregards a camera operator's experience significantly diminishes the benefits of using an OGI camera.

3. *EPA Should Increase the Time Between Survey Breaks*

GPA Midstream previously explained that requiring five minute survey breaks for every 20 minutes of monitoring lacked a record basis and would be unnecessary and unjustified for midstream facilities, which are far less complex than other facilities, such as oil refineries. Exh. A at 40. We do appreciate that EPA is now proposing a 10 minute break after every 30 minutes of monitoring, 87 Fed. Reg. at 74,839, however, this proposal raises the same concerns discussed in our January 2022 comments.

Although GPA Midstream agrees that OGI camera operators generally need breaks to avoid eye and mental fatigue, experience with field monitoring indicates that operators frequently receive breaks while walking through midstream facilities, which typically have a lower density of components requiring monitoring than at other types of facilities. Therefore, breaks should either be at the discretion of the camera operator, which will account for actual monitoring demands at a particular facility, or be increased to a 30 minute break after every two hours of monitoring. This will allow the OGI camera operator to develop a monitoring rhythm and more effectively survey larger facilities instead of requiring a stop every 30 minutes. During the two hour period the camera operator is likely to make smaller breaks from operating the camera. Some of these would include, drinking water, documenting a leak, performing a repair, or moving to another survey location.

4. EPA Should Eliminate or Revise Aspects of its "Operating Envelope"

GPA Midstream previously raised significant concerns with the Proposed Rule's camera performance criteria, termed "Operating Envelope conditions," as Proposed Section 8 of Appendix K would not be suitable for surveying locations in the remote or rural areas where gas plants often operate. *See* Exh. A at 40-41. The Supplemental Proposed Rule did not address these issues.

GPA Midstream further notes the contradictions between the detection requirements listed in Appendix K Section 6.1.2 and the initial performance verification requirements under Section 8.3 and 8.4. These letter two sections would require the establishment of an operating envelope that, contrary to Section 6.1.2, would require the establishment of operating envelopes for potentially hundreds of different configurations. Each configuration would not only require time to establish the operating envelope, but each one must be tested and documented under Section 8.6. This not only defeats the purpose of establishing the parameters listed under Section 6.1.2, but needlessly bogs operators down in recordkeeping requirements and actively discourages the use of OGI cameras.

Lastly, EPA should revise Section 6.1.2, which requires the OGI camera to be able to detect methane emissions of 17 grams per hour at a viewing distance of two meters. OGI cameras should be calibrated to accurately view methane emissions from farther away than two meters. An advantage of OGI cameras is that it reduces the need to elevate monitoring personnel by two meters or more to monitor "difficult to monitor" components. Section 6.1.2 would still require monitoring personnel to be elevated by two meters or more to monitoring components, erasing a significant advantage that OGI cameras would otherwise have.

5. *The Proposed Revisions to Senior Camera Operator Qualifications Do Not Resolve Concerns with the Likely Shortage of Qualified Operators*

GPA Midstream appreciates that the Supplemental Proposed Rule considered comments on senior camera operator requirements and proposed some revisions to proposed Appendix K based on those comments. 87 Fed. Reg. at 74,837-39. However, we urge EPA to make further revisions to the proposed Appendix K. Changing the senior camera operator requirements from 500 site surveys (with at least 20 site surveys in the prior year) to 1,400 survey hours (with 40 survey hours in the past year) does not alleviate the serious practical concerns GPA Midstream has with respect to the scarcity of operators that could qualify as senior camera operators. *See* Exh. A at 38-39. Not only do these requirements hinder midstream industry in-house personnel from qualifying as senior camera operators, but the auditing, training, and survey work that only senior camera operators can perform, and the initially small number of qualified operators available, would make senior camera operators very costly, if they are available at all. Even with the revised 1,400 hour requirement, it will likely take years to qualify enough senior camera operators to meet regulated industries' training, auditing, and survey needs under EPA's proposal.

GPA Midstream had previously surveyed their OOOOa OGI contractors and estimated an Appendix K survey would cost from two to three times more than an OGI survey under the current OOOOa standard. The modest changes to Appendix K requirements in the supplemental proposal do not make material changes that would reduce the substantial increase in expected costs for these types of surveys under proposed Appendix K. As proposed by EPA, this would remain a highly specialized position with significant training requirements, and it would take substantial time to ensure there are sufficient qualified operators to meet the demand resulting from the requirements established in this proposal. EPA should reduce the unduly burdensome requirements imposed in Appendix K – or it must factor in these real-world considerations and costs to these rules, which the record to date indicates have not been considered.

XI. EPA's Analysis of Costs and Benefits Includes Significant Errors and Omissions

EPA's cost and benefits review for the Supplemental Proposed Rule includes significant oversights with respect to the midstream industry. As explained in more detail below, owners and operators of gathering and boosting compressor stations do not own the gas that they process and, therefore, recoup no financial benefits from reducing lost gas as EPA assumed. Further, several necessary costs were omitted, such as compressor monitoring costs, installation costs, and the need for vapor recovery units. Overall, the analysis is incomplete and we urge EPA improve upon this analysis before making any determination on whether certain regulatory requirements are cost effective for the midstream industry.

A. EPA Should Examine Cost-Effectiveness on a Single Pollutant Basis

In reviewing whether control costs for the midstream sector are reasonable, EPA should look at the full cost of control as applied to each pollutant – VOCs and methane. Each pollutant should be evaluated separately as to whether the system would or would not be cost-effective in determining whether to require the control. Here, based on our review to date, when the proper set of costs are considered, it is plain that controls for centrifugal compressors at gas plants are not cost-effective.

EPA has long looked at whether the cost of a particular system of control is reasonable by considering the costs associated with such control, including capital costs and operating costs, determining the emission reductions that the control can achieve, and then evaluating whether a particular control achieves that emission reduction cost effectively. In this context, EPA has calculated a control's "cost-effectiveness" by taking the annualized cost of implementing an air pollution control option divided by reductions realized annually for that pollutant.

In this rulemaking, EPA has looked at cost-effectiveness using a single pollutant approach, but has also considered a "multi-pollutant" evaluation that divided control costs between VOCs and methane and then evaluated the cost-effectiveness of the control based on that reduced cost. 86 Fed. Reg. 63155 (Nov. 15, 2021). We urge EPA not to apply the so-called multi-pollutant approach in this case. Rather, in evaluating whether a particular "standard of performance" is appropriate here, EPA should look at each pollutant separately. This hews most closely to the direction of Congress. Section 111 requires EPA to consider a standard that reflects the degree of emission reduction achievable through the best system of emission reduction "taking into account the cost of achieving *such reduction*" as well as other factors. 42 U.S.C. § 7411(a)(1). In this case, the cost of achieving "such reduction" of methane is the full cost of control, not an apportioned cost or shared cost. The fact that there may be other benefits from installing the controls does not change the statutory requirement.

Not only is this approach consistent with the statutory language, it is the right policy choice here. The fundamental purpose behind EPA's regulation is reducing methane emissions, and thus it is the cost-effectiveness of the system of reduction for that particular pollutant that should be evaluated. *E.g.* 87 Fed. Reg. 63113 (Purpose of the Regulatory Action). But for the presence of methane emissions, it seems highly improbable that EPA would be embarking on this expansive effort to develop new regulations. Nor does this result in double counting of the cost of controls as others have suggested – it merely evaluates each pollutant on its own merits to assess whether "such reduction" meets the cost criteria in the statute.

B. EPA Should Correct its Cost-Effectiveness Analysis for Midstream, Because Gathering and Boosting Compressors See No Financial Benefits

In several locations throughout the Supplemental Proposed Rule, Regulatory Impact Analysis, and TSD, EPA asserts that gathering and boosting facilities own the natural gas in their systems and would directly benefit from capturing gas that would otherwise be lost. This is incorrect. Gathering and boosting facilities, and other midstream facilities, are typically paid a fee to prepare it for delivery to an interstate pipeline system. This is true even in large integrated companies that own both the production facilities and midstream facilities (*e.g.*, gathering and boosting compressors, processing plants). The production segment and the midstream segment are separate business units and the production segment still pays a fee to the midstream segment for processing. This makes the midstream segment much more like transmission and storage segment facilities instead of production facilities.

Because the Clean Air Act requires EPA to take "into account the cost of achieving" emission reductions, 42 U.S.C. § 7411(a)(1), EPA should revise and update its cost estimates to reflect the lack of financial benefits to the midstream sector. Given EPA's focus on the alleged benefits from enhanced recovery of methane, it is critical for EPA to correct its analysis and revise its cost effectiveness determination as applied specifically to the midstream sector. This is an issue GPA Midstream has raised previously, and we urge EPA to correct the record and redo its analysis for this proposed regulation. *See* Exh. A at 6-7.

C. EPA's Cost-Effectiveness Analysis is Incomplete, Because it Excludes Monitoring Costs For Compressors

EPA should likewise revise its analysis because it failed to include certain monitoring requirements for each compressor. In estimating the Supplemental Proposed Rule's cost effectiveness for compressors, EPA only considers a $15,000 annual repair cost for maintaining a dry seal compressor with an emission rate at or below the 3 scfm requirement. *See* TSD at 2-16. The Supplemental Proposed Rule, however, imposes annual flow monitoring requirements for each compressor. EPA does not account for any monitoring costs in its calculation. GPA Midstream members estimate that each gathering and boosting compressor station monitoring event costs approximately $4,290. With the average gathering and boosting compressor having four engines, this means that monitoring costs will exceed $16,000 – more than 100% of the costs EPA considered in its review. GPA Midstream members estimated that annual monitoring costs at processing plants will be approximately $6,750. With an average of four compressors, the annual costs per compressor should be increased to at least $16,500. This means that EPA's cost effectiveness review considers less than half of the actual costs imposed by the Supplemental Proposed Rule. EPA should revise its calculations and reconsider whether the Supplemental Proposed Rule is cost-effective.

D. EPA Should Collect Additional Information Regarding the Cost of Installing Zero Emission Pneumatic Devices at Gathering and Boosting Compressor Stations

As explained above, EPA incorrectly equates gathering and boosting compressor stations with oil and gas production facilities for purposes of analyzing cost effectiveness, dramatically underestimating the number of controllers required, the compressed air requirements, and other errors. To ensure that EPA accurately understands the costs imposed, it should gather additional information to create a representative gathering and boosting compressor station model plant.[30]

[30] GPA Midstream previously brought this problem to EPA's attention in its January 2022 comments with respect to the number of components that must be monitored for gathering and boosting compressor stations when compared to petroleum refineries. *See* Exhibit A at 36-37.

GPA Midstream would be pleased to discuss with EPA how it can obtain the information necessary to create a representative model gathering and boosting compressor station so that it may accurately estimate industry costs. However, GPA Midstream has endeavored to provide rough estimates of those costs here. They include the following differences from EPA's assumptions in the TSD:

- As discussed above, gathering and boosting compressor stations typically have many more than 20 controllers and require air compressors larger than 20 horsepower, as EPA assumed in the "Large Model Plant" for production sites.

- Based on data received from GPA Midstream member companies, the total capital cost for installing an air compressor for new controllers with grid power is between \$250,000 and \$1,000,000, depending upon the compressor station's size, layout, and the number of devices.[31]

- In Table 3-4 (solar powered devices) and Table 3-5 (grid powered devices) of the TSD, EPA appears to assume that any existing source switching from gas-driven devices to electric devices can still use the same valves. This is incorrect. In most cases, new valves would be required due to actuator setup changes.

The tables below (with changes highlighted) reflect more accurate costs for switching to electric devices:

[31] The \$1,000,000 estimate was for a gathering and boosting compressor station requiring approximately 100 controllers replaced. Assuming a mostly linear relationship, this equates to approximately \$10,000 per device. Even if EPA's Large Model Plant was applicable, the cost of installing 20 controllers would be approximately \$200,000, not the \$165,550 as EPA assumed.

TABLE 3-4. SOLAR

	2021$	2019$	Small Model Plant (4 controllers)	Medium Model Plant (8 controllers)	Large Model Plant (20 controllers)
New Sites					
Capital Investment ($)					
Electric Controllers with Valves	$4,000	$3,432	$13,729	$27,458	$68,644
Control Panel	$4,000	$3,432	$3,432	$3,432	$3,432
140 W Solar Panel	$400	$343	$343	$686	$1,373
100 Amh battery	$200	$172	$686	$1,373	$3,432
Solar Equipment Total			$18,191	$32,949	$76,881
Installation Costs			$9,095	$16,475	$38,441
Total Solar System Cost			$27,286	$49,424	$115,322
Cost of NG-driven controllers[a]	$2,595	$2,227	$8,907	$17,813	$44,533
Cost of NG-driven controller installation			$1,548	$3,096	$7,740
Total NG-driven costs			$10,455	$20,909	$52,273
Total Net Total Capital Investment			$16,831	$28,515	$63,049
Annual Costs ($/yr)					
Capital Recovery			$1,848	$3,131	$6,922
Maintenance		$80	$320	$640	$1,600
Replace Solar Panel		$34	$34	$69	$137
Replace Solar Batteries		$43	$172	$343	$858
Total Solar System Cost			$2,374	$4,183	$9,518
NG-Driven Maintenance		$140	$560	$1,120	$2,800
NG-Driven Replacement		$173	$692	$1,384	$3,460
Total Net Annual Costs			$1,122	$1,679	$3,258
Existing Sites					
Capital Investment ($)					
Electric Controllers with Valves	$4,000	$3,432	$13,729	$27,458	$68,644
Control Panel	$4,000	$3,432	$3,432	$3,432	$3,432
140 W Solar Panel	$400	$343	$343	$686	$1,373
100 Amh battery	$200	$172	$686	$1,373	$3,432
Solar Equipment Total			$18,191	$32,949	$76,881
Installation Costs			$18,191	$32,949	$76,881
Total Capital Investment			$36,381	$65,898	$153,763
Annual Costs ($/yr)					
Capital Recovery			$3,994	$7,235	$16,882
Maintenance			$320	$640	$1,600
Replace Solar Panel			$34	$69	$137
Replace Solar Batteries			$172	$343	$858
Total Solar System Cost			$4,520	$8,287	$19,478
NG-Driven Maintenance			$560	$1,120	$2,800
NG-Driven Replacement			$692	$1,384	$3,460
Total Net Annual Costs			$3,268	$5,783	$13,218

TABLE 3-5. ELECTRIC					
New Sites	2021$	2019$	Small Model Plant (4 controllers)	Medium Model Plant (8 controllers)	Large Model Plant (20 controllers)
Capital Investment ($)					
Electric Controllers with Valves	$4,000	$3,432	$13,729	$27,458	$68,644
Control Panel	$4,000	$3,432	$3,432	$3,432	$3,432
Electric Equipment Total			$17,161	$30,890	$72,076
Installation Costs			$8,581	$15,445	$36,038
Total Electric System Cost			$25,742	$46,335	$108,114
Cost of NG-driven controllers[a]	$2,595	$2,227	$8,907	$17,813	$44,533
Cost of NG-driven controller installation			$1,548	$3,096	$7,740
Total NG-driven costs			$10,455	$20,909	$52,273
Total Net Total Capital Investment			$15,287	$25,426	$55,842
Annual Costs ($/yr)					
Capital Recovery			$1,678	$2,792	$6,131
Maintenance		$80	$320	$640	$1,600
Grid Electricity		$4	$16	$31	$78
Total Electrical System Cost			$2,014	$3,463	$7,810
NG-Driven Maintenance		$140	$560	$1,120	$2,800
NG-Driven Replacement		$173	$692	$1,384	$3,460
Total Net Annual Costs			$762	$959	$1,550
Existing Sites					
Capital Investment ($)					
Electric Controllers with Valves	$4,000	$3,432	$13,729	$27,458	$68,644
Control Panel	$4,000	$3,432	$3,432	$3,432	$3,432
Electric Equipment Total			$17,161	$30,890	$72,076
Installation Costs			$17,161	$30,890	$72,076
Total Capital Investment			$34,322	$61,780	$144,153
Annual Costs ($/yr)					
Capital Recovery			$3,768	$6,783	$15,827
Maintenance			$320	$640	$1,600
Grid Electricity			$16	$31	$78
Total Electric System Cost			$4,104	$7,454	$17,506
NG-Driven Maintenance		$140	$560	$1,120	$2,800
NG-Driven Replacement		$173	$692	$1,384	$3,460
Total Net Annual Costs			$2,852	$4,950	$11,246

EPA should revise its cost estimates based on this additional information.

E. EPA Should Consider Compressor Emissions Created by Routing Pneumatic Controller Emissions to a Process

In Section 3.4.2 of the TSD, EPA incorrectly assumes no emissions would be associated with routing pneumatic controller emissions to a process. EPA states that these emissions streams would be at atmospheric pressure and would need a compressor to reach the sales gas or other process streams at a site. This is correct, but the agency further assumes that the compression needed would not result in emissions. This is incorrect. The compressor would result in direct emissions from a gas-fired engine driver or in indirect emissions from an electric driver. Either way, air emissions would be created to capture these pneumatic streams and send them to a process stream. EPA should update this paragraph even if the emissions are not calculated in the TSD so that future rulemakings will capture this option accurately.

F. EPA Should Include the Cost of a Vapor Recovery Unit, Because a Pneumatic Pump Requires a Vapor Recovery Unit to Capture and Route Emissions

In Section 4.3 of the TSD, EPA questions whether a Vapor Recovery Unit ("VRU") was needed for pneumatic pump emissions, as the emissions are similar to sales gas composition. *See* TSD at 4-2 to 4-3 ("since the emissions from pneumatic pumps are of the same composition as the natural gas in the "sales line," the EPA questions whether a VRU is needed to be able to process the gas and route it back to the sales line or otherwise use it in a process."). As a result, EPA did not consider the costs of installing a new VRU to control pneumatic pump emissions. *Id.*

This statement in the TSD is incorrect, as it comment misunderstands the purpose of a VRU at an oil and gas facility, including facilities in the midstream sector. A VRU captures low pressure vapors (atmospheric, in the case of pneumatic pump emissions) and increases the pressure so that stream can be routed into the sales or process stream. It is not used to change gas composition, as the TSD suggests. As such, EPA must include the necessary cost of installing and operating a VRU to capture and route pneumatic pump emissions to a sales or process stream. This VRU will most likely operate with supplied electricity and a screw compressor based on the volumes from pneumatic pumps; however, if no power is available onsite, the facility may need to install a gas- or diesel-fired engine to drive the VRU compressor. GPA Midstream would be pleased to work with EPA in gathering the necessary information to revise the pneumatic pump emission costs in the TSD.

G. EPA Should Further Revise its Cost Calculations, as the TSD Underestimates Other Costs for Routing Pneumatic Pump Emissions to a Control Device

Aside from the need to include the cost of installing and maintaining a VRU, the TSD underestimates other costs. For instance, GPA Midstream member companies' engineers when surveyed estimate that the costs for routing pneumatic pumps to an existing control device ranges from $150,000 to $300,000. This is far more than the $6,102 EPA estimated in Tables 4-7 and 4-10 based on oil and gas production well costs. Using the estimated lowest capital costs ($150,000) for gathering and boosting compressor stations, the cost effectiveness numbers are significantly different than what EPA has estimated for this rulemaking. As shown in the table below, the single pollutant and multipollutant cost effectiveness for methane and VOCs exceed the reasonable threshold level for each scenario listed. EPA should include these updated costs in the TSD, and for any future rulemakings, to make clear this control option is infeasible.

Control Option	Pump Type	Emissions Reduction (tpy)		Capital Cost	Without Savings				
					Annual Cost ($/yr)	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)	
		VOC	Methane			VOC	Methane	VOC	Methane
2. Routing to Combustion if Zero Emissions is Technically Infeasible									
b. Route Emissions to an Existing Combustion Device	One Diaphragm	0.91	3.29	$150,000	$21,357	$23,372	$6,497	$11,686	$3,249
b. Route Emissions to an Existing Combustion Device	One Piston	0.10	0.36	$150,000	$21,357	$212,804	$59,160	$106,402	$29,580
b. Route Emissions to an Existing Combustion Device	One Diaphragm + One Piston	1.01	3.65	$150,000	$21,357	$21,059	$5,854	$10,529	$2,927

XII. EPA Should Not Rely on the Social Cost of Methane for This Rulemaking, as the Interim Values are Deficient and Have Not Been Finalized

EPA relies on the February 2021 Interim Social Cost of Methane ("SCM") figures, along with supplementary materials, in order to estimate the purported projected climate and health benefits from the Supplemental Proposed Rule. As EPA recognizes, these figures are *interim* values, released pursuant to Executive Order 13990,[32] and have not been finalized. The Administration has not responded to public comments submitted by GPA Midstream and others identifying significant deficiencies associated with these interim values.[33] Indeed, recognizing the values require further scientific study, EPA and other agencies have begun an expert peer review of the administration's social cost analyses.[34] Until that peer review process is conducted and subject to public review and comment, it is inappropriate for EPA to consider the interim values to support its Supplemental Proposed Rule.

XIII. EPA Should Include a Reasonable and Commonsense Interpretation of the Waste Emissions Charge Provisions

EPA has requested comment on how to implement aspects of the "waste emission charge" under the CAA's Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems imposed as part of the Inflation Reduction Act (IRA). GPA Midstream supports EPA's request to consider public input and provide stakeholders direction on the implementation of the IRA framework, which could present an undue impact on the midstream sector. In particular, EPA should include direction on how to fairly apply the "exemption for regulatory compliance" provided in this new law, which encourages compliance as a way to minimize the financial charges that may result from the law. CAA § 136, 42 U.S.C. § 7436. Moreover, we support EPA's intention to provide a separate draft proposal on this topic to allow

[32] Exec. Ord. 13,990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, 86 Fed. Reg. 7,037 (Jan. 25, 2021).

[33] GPA Midstream, Comments Submitted on 86 Fed. Reg. 24,669 (May 7, 2021) (submitted June 21, 2021). GPA Midstream incorporates those comments here by reference. A copy is attached as Exhibit B.

[34] https://www.epa.gov/environmental-economics/scghg-tsd-peer-review

stakeholders to comment on specific regulatory text before issuing any final regulations. 87 Fed. Reg. 74720-21.

Under the IRA, EPA is directed to collect a Waste Emissions Charge on methane emissions that exceed a threshold from the owner/operator of an "applicable facility" that reports more than 25,000 tons of CO2 equivalent of GHGs under subpart W of EPA's GHG reporting rules. CAA § 136(c). An "applicable facility" is "a facility" within listed industry segments. CAA § 136(d). The charge is established by an equation derived by determining the excess of reported emissions above a defined threshold and multiplying that excess by a set dollar amount specified in the statute. CAA § 136(e)-(f). The charge does not apply to emissions that result from unreasonable delay in permitting or other necessary infrastructure development. CAA § 136(f)(5).

The IRA also included an "exemption for regulatory compliance," under which charges would also not be applied to a facility that is subject to and in compliance with methane emissions under CAA §§111(b) and (d). This exemption is conditioned upon a determination by EPA that (i) methane emissions standards under CAA § 111(b) (for new sources) and plans under CAA § 111(d) (for existing sources) have been approved and are in effect with respect to the facility and that (ii) compliance with the standards and plans would mean equivalent or greater emissions reductions that would have been achieved had EPA's November 2021 proposal been converted to regulatory text and finalized.

In fashioning a proposal on this topic, among other issues, EPA should i) view a "facility" using the common sense notion of an operating site, ii) provide common sense guidance regarding the meaning of "in compliance" to qualify for the exemption , and iii) adopt a "notice and cure" process that would allow a reasonable time to cure any material non-compliance before EPA or the relevant state assesses a waste emission charge.

A. EPA Should Apply A Common Sense Definition of "Applicable Facility"

As a fundamental matter, EPA should apply a common sense definition of "applicable facility" to harmonize the different requirements in the waste emissions charge. *See* Comments of GPA Midstream, Response to Request for Information, "Methane Emissions Reduction Program," Docket ID Nos. EPA-HQ-OAR-2022-0875, EPA-HQ-OAR-2022-0875-0002 (submitted January 18, 2023) ("GPA Midstream Comments to MERP Docket"). *See* Exhibit F.

Accordingly, in fashioning a proposal, EPA should view a "facility" using the common sense notion of an operating site – not the equipment-level "affected facility" used in OOOOb/c, nor the basin-level "facility" used in Subpart W. Throughput should similarly be based on discrete sites (i.e., each gathering and boosting compressor station). Any other interpretation would result in arbitrary treatment among industry segments and would lead to significant uncertainty as operators attempt to parse out what exactly is and is not a "facility" and how to correctly assess facility throughput. To address this potential confusion, EPA should revise Subpart W throughput reporting elements for gathering and boosting to allow reporters to reflect true facility throughput.

If EPA utilizes existing regulatory definitions to define a "facility," implementation of the IRA's language will be particularly challenging in that the terms "facility" and "facilities" have vastly different meanings in Subpart W and OOOOb/c, and those meanings themselves do not necessarily align with the public's understanding of what these words mean. In OOOOb/c, the "affected facility" is an individual piece of equipment (or group of equipment, like all the natural gas-driven pneumatic controllers at a gas plant). On the opposite side of the spectrum, under Subpart W, a gathering and boosting "facility" includes all gathering and boosting emission sources within a basin, which is usually a large geographic area spanning many counties and sometimes many states. Neither the OOOOb/c nor the Subpart W gathering and boosting facilities definitions are consistent with a general understanding of the word "facility." Accordingly, GPA suggests that EPA use the simplest interpretation of the term, which is that "a facility" is a single site, and not specific pieces of equipment within that site, nor the aggregation of hundreds of sites within a geographic area. We think this is straightforward and "bridges the gap" between OOOOb/c and Subpart W.

B. EPA Should Apply a Reasonable Substantial Compliance Standard for Determining Whether a Facility Is Sufficiently "In Compliance" to Meet the Exemption

In addition to evaluating compliance at "a facility" using a common sense interpretation, EPA should reasonably interpret the phrase "in compliance." GPA Midstream provided suggestions on how we believe EPA should apply the exemption for regulatory compliance in its MERP comments, which it incorporate here. GPA Midstream Comments to MERP Docket at 7-8.

Among other considerations, GPA Midstream urges EPA to recognize the challenges with real world compliance with complex and detailed regulatory requirements and interpret the exemption reasonably to allow some measure of flexibility in determining whether a facility is "in compliance." In the real world, it is unreasonable to expect, if not impossible, for an individual affected facility to establish strict 100% "compliance" with all aspects of complex rules. Non-compliance can arise from minor technical or paperwork deviations or other process-related issues leading to brief emissions exceedances. It would be unreasonable for EPA to determine that a facility loses its regulatory compliance exemption for an entire year where it submits a late report or barely exceeds a threshold for a few minutes on one day, while reporting compliance the rest of the year. Such a narrow and strict approach would be unduly punitive and contrary to the basic notions of due process. Therefore, EPA should adopt a reasonable standard for determining compliance and ensure such standard sufficiently and equitably accounts for EPA's chosen interpretation of "applicable facility." To that end, GPA Midstream urges EPA to consider a reasonable "substantial compliance" standard, allowing an appropriately flexible approach to avoid the harshness of what could otherwise be a significant financial burden. EPA and states could provide further guidance on reasonable limits for this approach.

In addition, "in compliance" should allow for a broad safe harbor for a facility to promptly correct instances of non-compliance, consistent with routine monitoring, a compliance assessment or other auditing function. There is a well-worn path for regulated parties to follow, such as that laid out in EPA and state audit disclosure policies, that would provide an established mechanism for prompt correction of any non-compliance. Again, allowing this as a way to qualify for the exemption would incentivize sources to conduct additional compliance assessments and to timely correct any issues identified.

C. EPA Should Include a Mechanism for the Agency to Provide Advance Notice to A Facility to Allow the Opportunity to Address and Cure Any Non-Compliance

In addition to EPA adopting a reasonable interpretation of what it means to be "in compliance," given the significant financial implications for non-compliance, it is also important for EPA and state permitting agencies to apply this standard fairly and in a manner consistent with due process standards.

To that end, we suggest that EPA incorporate a "notice and cure" process into its implementation of the waste emission exemption process. First, EPA is authorized to revise its reporting regulations to ensure the emissions data reporting is accurate. CAA § 136(h). As part of those regulations, EPA should provide that applicable facilities would not be subject to a charge that may otherwise be owed unless and until EPA, or the relevant state permitting agency, issue a notification that the facility is not in substantial compliance with applicable Section 111(b) or (d) emission standards or requirements and that, if not promptly cured, a waste emissions charge will be assessed. This would provide a financial incentive for the facility so notified to correct any issues to be in compliance.

A notice and cure process would also ensure the waste emission charge is applied only where a facility has in fact failed to qualify for the regulatory exemption. A facility should not lose its regulatory compliance exemption for an entire year for non-material compliance concerns, such as a late report or minor exceedance of a threshold for a few minutes on one day. Similarly, a facility should not lose its regulatory compliance exemption where there is disagreement between a facility and EPA, or the governing state, regarding the application of a standard or the relevant state plan. Determining whether a facility is "in compliance" is highly fact-specific and could be highly subjective without adequate safeguards. Here, a notice and cure process will better serve both EPA and regulated entities in fairly applying the charge to the correct facilities. To accomplish that, the notice and cure process should provide a facility the option to confer promptly with EPA or the relevant state regarding the notice in the event the facility disputes the regulator's findings. That will allow a reasonable opportunity to resolve potential disagreements prior to a final waste emission charge assessment. There should also be an opportunity for the facility to exercise its rights to question the charge through a form of administrative or judicial review under the CAA. Applying the waste emission charge without notice and cure opportunities would be unduly punitive and contrary to the basic notions of due process.

Moreover, this type of procedure would be consistent with the framework EPA has created. In CAA § 136(f)(6)(B), Congress provided EPA with authority to resume charging a facility after first applying the compliance exemption where EPA later determines that either of the two conditions at CAA § 136(f)(6)(A)(i)–(ii) were no longer met (e.g., methane emission standards not approved or not in effect in an applicable state). It stands to reason, therefore that prior to determining whether these two conditions have been met to have applied the exemption, EPA should first determine whether the facility is "in compliance" with applicable methane emission requirements, consistent with CAA § 136(f)(6)(A). Having EPA provide the requisite notice fits seamlessly with this framework.

D. EPA Should Evaluate A Facility's Compliance as of the Supplemental Proposed Rule's Effective Date

As noted, in addition to being "in compliance" with applicable Section 111 standards, Congress placed two additional conditions on the waste emission charge exemption. Specifically, the EPA Administrator has to make a "determination … that (i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 7411 of this title have been approved and are in effect in all States with respect to the applicable facilities" and "(ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions" than EPA's November 2021 proposal. 42 U.S.C. § 7436(f)(6)(A).

With regard to the timeline for making these determinations, GPA Midstream urges EPA to interpret Section 136(f)(6)(A) to be reasonably consistent with the overall intent to incentivize sources to comply with Section 111. Hence, with regard to new sources, EPA should confirm that, for purposes of determining that the waste emission charge exemption applies, it will use the Subpart OOOOb effective compliance date and make the necessary evaluation of equivalency at the time it issues a final rule. This will ensure a reasonable application of the regulatory compliance exemption from the waste charge. There is no reason for a new source subject to Section 111(b) to wait for any state to choose to incorporate new source emission standards. As states are not obligated to adopt such standards for the standards to be "in effect" in a state, *see* 42 U.S.C. § 7411(c), such an interpretation could render the exemption a nullity, even if only temporarily, for those sources within states that delay or choose not to adopt their own new source standards. Likewise, it would be illogical to wait for a state to propose and implement a plan for existing sources that would not apply to the new source subject to Section 111(b) standards. Such an interpretation would accomplish the opposite of Congress's intent in creating the exemption, by punishing complying facilities rather than incentivize continued compliance.

EPA should likewise adopt a reasonable interpretation of the direction for standards and plans to be in effect "with respect to" the applicable facilities. Accordingly, EPA should allow sources that comply with the Subpart OOOOc emission guidelines, establishing the minimum "standards and plans" for the facility, to be able to show compliance and thereby establish coverage for the exemption. That would incentivize sources to comply early—even before a state goes through what can be an often long planning and adoption process. At a minimum, EPA should confirm that the reference to "all states" does not mean a facility must await for other states to act. Waiting for each and every state to adopt an EPA-approved plan would otherwise unfairly restrict a facility's ability to utilize the exemption, contrary to Congress' intent.

XIV. The Proposed Requirements for States to Show Their State Plan is Equivalent to EPA's OOOOc Emissions Guidelines Are Contrary to the Clean Air Act

The Supplemental Proposed Rule's various proposed changes to how States will establish emission limitations for existing sources raises numerous legal and factual concerns. We urge EPA to rethink this approach.

To begin, EPA is proposing through the Supplemental Proposed Rule to finalize significant changes to Subpart Ba, governing how States establish existing source performance standards, while simultaneously proposing similar changes through a separate rulemaking. *See* 87 Fed. Reg. 79,176 (Dec. 23, 2022) ("Proposed Subpart Ba Rule"). There are not only differences between the two proposals, but the Supplemental Proposed Rule suggests EPA has already determined what revisions it will make to Subpart Ba regardless of the public notice and comment process required under the Administrative Procedure Act. EPA should await its Ba rulemaking and follow those procedures, rather than create separate procedures in this rule.

More fundamentally, we urge EPA to rethink its approach, because its proposal is contrary to Congress' clear direction in the plain language of Section 111(d) to grant the States substantial discretion to develop their governing plans for existing sources. Yet, the substance of the EPA's proposal would impose an unprecedented level of federal micro-management over how States would establish emission limitations for existing sources and strip away the discretion that Congress gave to the States under Section 111(d). In support of its proposal, EPA has selected out phrases from the statute to create its "satisfactory plan" and "standards of performance" theories for interpreting the Act. But, EPA's reading is contradicted by Section 111's plain language and structure, as well as case law interpreting that statute.

Even if these proposed revisions were lawful – and GPA Midstream believes that they clearly are not – the rationale for imposing them lacks a record basis, includes impermissibly vague requirements, and will have the effect of making States' consideration of facilities' remaining useful life and other factors so onerous as to be practically impossible, despite Congress expressly authorizing States to consider those matters.

A. <u>The Supplemental Proposed Rule is Neither the Vehicle for Proposing Revisions to Subpart Ba Nor Should it Assume that Such Proposed Revisions are Already Effective</u>

First, EPA should address any potential changes to the process for states to develop state plans under EPA's separate, pending rulemaking to revise subpart Ba, not this rulemaking.

The Supplemental Proposed Rule's preamble explains EPA would conduct "a source-by-source evaluation" to determine whether a State's submitted program may be deemed equivalent to the proposed presumptive standards. *See* 87 Fed. Reg. at 74,814 (proposing "five basic criteria" for equivalency analysis). However, those criteria are not found in 40 C.F.R., Part 60, Subpart Ba, which governs EPA's review of state plans submitted under Section 111(d). EPA notes that it is proposing to revise Subpart Ba through a separate rulemaking, but the Proposed Subpart Ba Rule also does not contain or reference the proposed "five basic criteria" described in the Supplemental Proposed Rule. It is illogical for EPA to be using preamble language to attempt to fashion separate criteria for just this proposal.

EPA also proposes major revisions to when States may consider facilities' remaining useful life or other factors ("RULOF") to establish less stringent emission limits for a facility or class of facilities. 87 Fed. Reg. at 74,817. Here, the Supplemental Proposed Rule is clearly mandating that

States use the new criteria for RULOF that are not found in existing regulations. Instead, the Supplemental Proposed Rule incorporates new standards from the *Proposed* Subpart Ba Rule.

We urge EPA to reconsider this approach as well. By proposing the same or similar revisions in two separate rules, EPA gives the appearance that the Proposed Subpart Ba Rule is a *fait accompli*, already determined by EPA to be effective in practice before it was even proposed, much less before EPA considered public comments on the Subpart Ba Rule and finalized it. This is impermissible under the Administrative Procedure Act. *See*, *e.g.*, *Nat'l Tour Brokers Ass'n v. United States*, 591, F.2d 896, 902-03 (D.C. Cir. 1978) (the purpose of the Administrative Procedure Act's public comment provision is so that the agency may "benefit from the expertise and input of the parties who file comments" and "maintain[ ] a flexible and open-minded attitude towards its own rules"); *U.S. Steel Corp. v. EPA*, 595 F.2d 207, 214-15 (5th Cir. 1979) (agency must "ensure that affected parties have an opportunity to participate in and influence agency decision making at an early stage, when the agency is more likely to give real consideration to alternative ideas").

Instead, EPA should withdraw the portion of the Supplemental Proposed Rule that purports to implement revisions to Subpart Ba so that the Proposed Subpart Ba Rule may proceed separately and under the normal rulemaking process.[35] This does not need to delay this rulemaking. In the meantime, EPA may simply proceed under existing regulations for state plans while the agency finalizes revisions to subpart Ba.

B. EPA Lacks Authority to Impose Substantive Conditions on the States' Use of RULOF

GPA Midstream also urges EPA to drop its attempt to revise its rules to limit the discretion given states to implement its authority governing existing sources. Nothing in Section 111 of the Act provides EPA with the authority to impose what the Supplemental Proposed Rule calls "threshold requirements for considering Remaining Useful Life and Other Factors." 87 Fed. Reg. at 74,819-25. These "threshold requirements" are impermissible substantive conditions on when or how States may exercise the discretion Congress granted the States in considering RULOF to establish existing source emission standards under Section 111(d).

Moreover, EPA should likewise not finalize these regulatory changes, which are directly contrary to the text of the statute and the cooperative-federalism structure of Section 111(d), which relegates the Agency to a limited role. EPA cannot unilaterally re-define the roles that Congress assigned to each of EPA and the States through counter-textual interpretations of the terms "satisfactory plan" and "standards of performance." Further, the proposed multitude of conditions and requirements that States would have to satisfy ill-conceived, lack a record basis, and are collectively so onerous that EPA would deprive States of an option that Congress clearly provided under the statute.

[35] GPA Midstream plans on submitting comments on the Proposed Subpart BA Rule and incorporates those comments here by reference.

For all of these reasons, EPA should withdraw its various unlawful conditions on the States' use of RULOF.

1. EPA's Role Under Section 111(d) is Limited to Establishing Procedural Regulations While States Establish Standards of Performance

EPA has erred in the Supplemental Proposed Rule by improperly seeking to alter the respective responsibilities of EPA and the States under Section 111(d)(1). In short, while EPA establishes emission limitations for new sources under Section 111(b), the States establish emission limitations for existing sources under Section 111(d) with EPA playing a very limited procedural role. Section 111(d)(1) only permits the Administrator to "prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the administrator a plan" for existing sources. 42 U.S.C. § 7411(d)(1). Those procedural regulations will differ from Section 7410 only in that they "shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." *Id.* Section 111(d)(1) does not authorize the Administrator to impose conditions on the approval of a State plan. Therefore, if such authority exists, it must come from Section 110. Yet, the Supplemental Proposed Rule never examines EPA's authority under Section 110. However, nothing in Section 110 provides EPA with any substantive powers in establishing Section 111(d)(1) emission limitations.

Section 110(k) governs EPA's review of State plans and actions on them. Of relevance, EPA must make a completeness find within 60 days indicating whether or not the state plan meets minimum statutory criteria, 42 U.S.C. § 7410(k)(1)(B), and either approve, partially approve, conditionally approve, or disapprove a state plan depending upon whether "it meets all of the applicable requirements of this chapter." *Id.* § 7410(k)(3). Thus, Section 7410, as incorporated by 7411(d), only authorizes EPA to create a procedural framework for the submission, review, and approval (or disapproval) of a state plan. Approval or disapproval is based on statutory criteria only (*i.e.*, "applicable requirements of this chapter"). Nothing in either Section 7410 or 7411(d) authorizes EPA to impose additional substantive requirements on when States may use RULOF and EPA has not identified any statutory ambiguity that it is interpreting.[36]

Further, the D.C. Circuit very recently held that EPA's interpretation of Section 111(d) responsibilities is impermissible. EPA cites to *American Lung Association v. EPA*, 985 F.3d 914 (D.C. Cir. 2021) to summarize the 2019 Affordable Clean Energy Rule litigation, 87 Fed. Reg. at 74,812, 74,817, but it ignored the D.C. Circuit's explanation of the different roles that EPA and the States serve under Section 111(d). As the court stated: "Once the EPA identifies a best system that meets" the requirements of Section 111(a) "and calculates the degree of emission limitation it allows, the Clean Air Act leaves it to the States to set their own standards of performance for their existing pollution sources." 985 F.3d at 962 (emphasis added). "The cooperative-federalism design of Section 7411(d) gives the States broad discretion in achieving those limitations." *Id.* In fact,

[36] *See*, *e.g.*, *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (agencies cannot re-write unambiguous statutory terms as they only have discretion to interpret ambiguous language); *Michigan v. EPA*, 268 F.3d 1075, 1082 (D.C. Cir. 2001) ("Mere ambiguity in a statute is not evidence of congressional delegation of authority.").

"under Section 7411(d), the EPA does not impose the 'best system of emission reduction' on anyone. Instead, each State decides for itself what measures to employ to meet the emission limits, and in so doing may elect to consider the 'remaining useful life' of its plants and 'other factors.'" *Id.* Notably, this was not merely a concurrence with an agency interpretation that EPA would be free to change in the future; this was the court's explanation of Section 111's unambiguous "statutory design." *Id.* Thus, both the text of Section 111, and a recent D.C. Circuit interpretation of that text, make it clear that Congress did <u>not</u> provide EPA with <u>any</u> authority to regulate how States establish existing source emission limits under Section 111(d) or to cabin the "broad discretion" provided to States under that statute.

2. The Supplemental Proposed Rule's "Satisfactory Plan" Interpretation is Contradicted by the Statute and is Unreasonable

In support of its proposal, EPA relies on an erroneous interpretation of Section 111(d), as EPA would substantially alter the roles of EPA and the States established by statute's text and structure and recognized by the D.C. Circuit, based on a strained and implausible reading of Section 111(d)<u>(2)(A)</u>. That sub-section governs federal implementation plans promulgated where a "State fails to submit a satisfactory plan" as the Administrator "would have under section 7410(c) of this title in the case of failure to submit an implementation plan." Instead of naturally interpreting this sub-section as providing EPA with the authority to issue federal emission standards for existing sources whenever a State either fails to submit a plan or the plan is disapproved (a reading that tracks the referenced Section 7410(c)), EPA proposes to read the term as giving it a super power to limit the States' authority in the first place. According to EPA, the phrase "satisfactory plan" grants EPA vast and unprecedented powers to impose extensive conditions that restrict how States establish existing source emission limitations. According to the Supplemental Proposed Rule, "the most reasonable interpretation of a 'satisfactory plan' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d), including the provisions governing the application of RULOF." 87 Fed. Reg. at 74,818. This interpretation violates several basic rules of statutory construction and is, therefore, not a reasonable (or even permissible) reading of Section 111.

To begin, EPA's interpretation merely begs the question. It declares that EPA has the authority to regulate a State's use of RULOF because a "satisfactory plan" must comply with EPA regulations governing a States' use of RULOF. Thus, the Supplemental Proposed Rule presupposes an authority to regulate the States without actually trying to find such an authority in Section 111(d)(1) – an impossible task, given the subsection's text and structure, as well as the D.C. Circuit's ruling.

Further, EPA's "satisfactory plan" interpretation violates basic principles of statutory construction. Thus, it is not a reasonable construction of Section 111(d)(1) and will warrant no deference in court. *See Chevron USA Inc. v. NRDC, Inc.*, 467 U.S. 837, 844 (1984) (courts will only defer to "a reasonable interpretation made by the administrator of an agency"). For instance, the interpretation reads the following statutory terms out of the text:

- Under Section 111(d)(1), the Administrator is limited to "prescrib[ing] regulations which shall establish a procedure similar to that provided by Section 7410 of this title." Under the "satisfactory plan" interpretation, the Administrator would have virtually unlimited substantive powers to establish existing source standards of performance by prohibiting States from exercising their own discretion, not the mere power to "establish a procedure."

- Under Section 111(d)(1), "each State," not EPA, "establishes standards of performance for any existing source for any air pollutant." Under the "satisfactory plan" interpretation, EPA would dictate how standards of performance for existing sources would be established, not States.

- Under Section 111(d)(1),"the State," not EPA, "take[s] into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Under the "satisfactory plan" interpretation, the States' "consideration" of RULOF would be so circumscribed by EPA as to become a mere mechanical exercise of endorsing EPA's emission guidelines.

- Under Section 111(d)(2), EPA only has the authority described in Section 7410(c). That section allows for a Federal Implementation Plan when a State Implementation Plan is disapproved for a failure to comply with the statutory requirements of Section 7410(k)(1)(A). Nothing in Section 7410(c) provides EPA with authority to create new standards with which a State plan must comply. Under the "satisfactory plan" interpretation, Congress' cross-reference to Section 7410(c) would be meaningless and the sub-section's language would effectively terminate after the phrase "fails to submit a satisfactory plan."

In fact, EPA's "satisfactory plan" interpretation improperly re-writes Section 111(d) as to render the majority of Section 111(d)(1)'s text, and half of Section 111(d)(2)(A)'s text, superfluous. *See*, *e.g.*, *Hibbs v. Winn*, 542 U.S. 88, 101 (2004) (a "statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant") (internal quotations omitted). The Supplemental Proposed Rule's "satisfactory plan" approach is not a permissible interpretation of the statute, much less a reasonable one.

Nor does the "satisfactory plan" interpretation consider the overall context and structure of Section 111. A "reasonable statutory interpretation must account for both 'the specific context in which … language is used' and 'the broader context of the statute as a whole.'" *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2442 (2014) (quoting *Robinson v. Shell Oil Co.*, 519 U.S. 337, 341 (1997)) (alterations in original); *see also Univ. of Texas Southwestern Med. Ctr. v. Nassar*, 570 U.S. 338, 353 (2013) (interpretations cannot be "inconsisten[t] with the design and structure of the statute as a whole"). The "satisfactory plan" interpretation would make Congress' clear decision to split the responsibility for establishing standards of performance between EPA (new sources) and the States (existing sources) completely illusory as, despite the text and structure, EPA would dictate standards of performance under both subsections.

And, finally, the "satisfactory plan" interpretation is of a type that courts have strongly and repeatedly disfavored. "Congress, we have held, does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes." *Whitman v. Amer. Trucking Assns., Inc.*, 531 U.S. 457, 468 (2001). Courts are especially skeptical of such interpretations where, as here, an agency appeals to "vague terms or ancillary provisions" to overcome specific statutory delegations of authority. *Cf. Banks v. Booth*, 3 F.4th 445, 449 (D.C. Cir. 2021) ("Appellees would have us hold that after having gone to this trouble with specificity to state exactly what it meant, Congress *sub silentio* created a further exception to its clear meaning … we are not going to hold that Congress enumerated the mice and then unleashed an invisible elephant to trample the field."). Here, the Supplemental Proposed Rule uses the vague and ancillary term "satisfactory plan" – residing in Section 111(d)(2)(A) – to wrench away the clear authority that Congress provided to States in Section 111(d)(1). Nothing in the term "satisfactory plan," or its surrounding context, indicates that Congress intended to modify Section 111(d)(1), much less provide EPA with the power to almost entirely constrain the States' "broad discretion" under that subsection. *Amer. Lung Ass'n*, 985 F.3d at 962.

3. *The Supplemental Proposed Rule's "Standards of Performance" Interpretation is Unreasonable and Impermissible*

The Supplemental Proposed Rule separately argues that "there is a fundamental obligation under CAA section 111(d)" that existing source emission limits "reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA." 87 Fed. Reg. 74,816 (emphasis added). This argument claims that, because Section 111(d) uses the term "standard of performance," then Congress silently intended for EPA to establish existing source emission limits under Section 111(d)(1), not the States. *Id.* For the same reasons as the "satisfactory plan" interpretation, the "standard of performance" interpretation is an impermissible and unreasonable one that lacks a statutory basis, contradicts Section 111(d)'s text and structure, and violates basic principles of statutory construction.

C. The Supplemental Proposed Rule Provides no Reason Why the RULOF Revisions are Needed

Even if EPA had the authority to impose new conditions on States' use of RULOF, the Supplemental Proposed Rule fails to provide a rational, record-based reasoning for those conditions. Instead, the Supplemental Proposed Rule bases its proposed revisions on a series of hypothetical scenarios that do not withstand serious scrutiny. Again, we urge EPA to reconsider its approach.

As we understand it, the premise in EPA's proposal is that its regulations regarding RULOF, 40 C.F.R. § 60.24a(e), which were revised only four years ago, now lack "clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency." 87 Fed. Reg. at 74,817.[37] Nothing about § 60.24a(e) is problematic. States

[37] GPA Midstream agrees with the Supplemental Proposed Rule's statement that, while the 2019 revisions to Subpart Ba were challenged, that challenge did not encompass 40 C.F.R. § 60.24a(e) and the court in *American Lung Association v. EPA* did not vacate that regulation. 87 Fed. Reg. at 74,817.

may demonstrate that applying the presumptive standard of performance (1) involves unreasonable costs due to a plant's age, location, or process design, (2) physically impossible, or (3) involves other factors "that make application of a less stringent standard or final compliance time significantly more reasonable." 40 C.F.R. § 60.24a(e). The existing regulation employs a rule of reason – a very commonly used standard under the Administrative Procedure Act – and factor (3) is open-ended, as it must be given Congress' decision to allow States to consider unenumerated "other factors" instead of creating a definitive list of considerations.

According to the Supplemental Proposed Rule, however, Section 60.24a(e) "does not provide clear parameters for states on how and when to apply" RULOF. 87 Fed. Reg. at 74,818. More specifically, EPA worries that "the reference to reasonableness in this provision are potentially subject to widely differing interpretations and inconsistent application among states developing plans, and by the EPA in reviewing them" that "could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless." *Id.* There are multiple problems with this rationale.

First, it is entirely speculative. The Supplemental Proposed Rule has not identified any questions that have arisen from the actual application of Section 60.24a(e). In fact, the Supplemental Proposed Rule "did not identify any provision in any of the state oil and natural gas regulations that included a less stringent standard for equipment or operations with a shortened lifespan." 87 Fed. Reg. at 74,818. In other words, EPA has no information showing that the proposed revisions are necessary or helpful, as no State has yet used the RULOF provisions for crude oil or natural gas sources.

Second, the concern that States "could" apply RULOF in a way that "effectively undermine[s] the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless," *id.*, is not only speculative, but it misunderstands Section 111(d)'s purpose. EPA's BSER determination in its emission guidelines is always a starting point for States under Section 111(d), and therefore, it could never be "meaningless" EPA's proposal asserts. But most importantly, and contrary to the EPA's concern, <u>the Congress</u> <u>intended</u> that States, under certain circumstances, be free to implement standards less stringent than EPA's BSER determination. As one court explained, "[a]s with most legislation, the Clean Air Act amendments reflected a congressional compromise … As one legislative compromise, the Clean Air Act has less stringent regulations regarding existing power plants as compared to newly constructed sources of electricity. In other words, existing plants were 'grandfathered' in recognition of the expense of retrofitting pollution-control equipment." *United States v. EME Homer City Generation LP*, 823 F. Supp. 2d 274, 279 (W.D. Pa. 2011) (citing Section 111(d)); *see also WEPCO v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) (citing legislative history justifying more lenient emission standards for existing sources).

Thus, the entire purpose of Section 111(d)'s RULOF provision is to allow States to implement emission limitations less stringent than BSER where the States believe that the remaining useful life – and unenumerated "other factors" – warrant it. Revising the implementing regulations to prohibit, or severely restrict, a State's ability to implement less stringent emission standards when considering "among other factors, the remaining useful life of the existing source," 42 U.S.C. § 7411(d), is contrary to the statutory purpose, the legislative compromise and the principles of federalism embodied in Section 111. As discussed above, the notion that existing source emission limits must hew to "the overall presumptive level of stringency envisioned by the EPA's BSER determination," is contrary to the statute's text and structure, which provide the States' with "broad discretion" in establishing existing source limits. *Amer. Lung Ass'n*, 985 F.3d at 962. Thus, ensuring consistency between 111(b) new source standards and 111(d) existing source standards is not a legitimate rationale.

Third, Section 111(d) does not indicate that Congress believed that consistency between or among State existing source standards was either necessary or desirable. As the D.C. Circuit explained, "each State decides for itself what measures to employ to meet the emission limits, and in so doing may elected to consider the 'remaining useful life' of tis plants and 'other factors.'" *Amer. Lung Ass'n*, 985 F.3d at 962. The Supplemental Proposed Rule does not identify anything in Section 111(d) that justifies a contrary interpretation. This means that its concern that "the references to reasonableness in" 40 C.F.R. § 60.24a(e) "are potentially subject to widely differing interpretations and inconsistent application among the states," 87 Fed. Reg. at 74,818, is directly contrary to the statutory framework in Section 111 and the broad discretion afforded to individual States to decide "for itself."[38]

Fourth, EPA and States have been implementing air emission standards that incorporate the "remaining useful life" of regulated facilities under the Regional Haze program for decades without any concern for "widely differing interpretations and inconsistent application among states developing plans." 87 Fed. Reg. at 74,818. As with Section 111(d), the Regional Haze program gives States primary authority to establish air pollutant emission limitations that consider "the remaining useful life of the source" and other factors. 42 U.S.C. § 7491(g)(2); *see also* 40 C.F.R. §§ 51.301 ("remaining useful life" included in the definition of Best Available Retrofit Technology); 51.308(d)(1)(i)(A) (States consider "remaining useful life" in establishing Reasonable Progress Goals); 51.308(e)(1)(ii)(A) (determining Best Available Retrofit Technology); 308(f)(2)(i) (emission reduction measures that consider the "remaining useful life"). EPA and the States have collectively handled several dozen Regional Haze plans since 1999 without any indication that the methodology for State consideration of "remaining useful life" was confusing, inappropriately inconsistent, or frustrating the underlying goals of the Regional Haze program. Thus, the Supplemental Proposed Rule's claim that Section 111(d)'s implementing regulations require significant changes to resolve confusion or improper inconsistency surrounding RULOF is contradicted by the absence of such problems under the Regional Haze program.

D. The Proposed RULOF Criteria are Fundamentally Flawed

Even assuming EPA could create these RULOF criteria, the proposed requirements are, individually, arbitrary and capricious. Collectively, they would make State consideration of RULOF in establishing existing source emission standards so onerous and burdensome that EPA

[38] In addition, the Supplemental Proposed Rule's claim that the Section 60.24a(e)(1) reasonableness standard ("Unreasonable cost of control") is so vague that it necessitates clarification, 87 Fed. Reg. at 74,819, is contradicted by its simultaneous proposal to retain the "unreasonable cost of control" standard. *Id.* at 74,820. GPA Midstream supports retaining the "unreasonable cost of control" standard but the Supplemental Proposed Rule's argument that a standard it proposes to retain justifies revisions to other aspects of the regulations is arbitrary and capricious.

would effectively foreclose an option that Congress specifically provided to States. The result is that States would be forced to implement EPA's presumptive standards, surrendering to EPA the "broad discretion" that Congress intended them to exercise.

1. The Proposed "Fundamentally Different" Criterion is Fundamentally Flawed

To satisfy RULOF, EPA has created criteria based on cost, physical impossibility or technical impracticability, and "other factors specific to the facility (or class of facilities) that are fundamentally different from the factors considered in the determination of the best system of emission reduction" in EPA's emission guidelines. Proposed § §60.5365c(a)(1)-(3).

We urge EPA to reconsider the "fundamentally different" criteria, as it is flawed in at least two ways. First, "fundamentally different" is just as vague and ambiguous as "reasonable," the word that EPA claims requires additional definition. 87 Fed. Reg. at 74,819. Second, it practically requires that a State demonstrate that EPA's presumptive standards are arbitrary and capricious in a specific application. Nothing in Section 111(d) indicates that Congress intended for States to consider RULOF only in extreme, outlier scenarios that are "fundamentally different."

In fact, the Supplemental Proposed Rule illustrates how impractical RULOF would become under this "fundamentally different" criterion by claiming that States must demonstrate that BSER costs "would be exorbitant, greater than the industry could bear and survive, excessive, or 'unreasonable." 87 Fed. Reg. at 74,818 (internal quotations omitted); *see also id.* at 74,819 ("RULOF will be applicable only for a subset of sources for which implementing the BSER would impose unreasonable costs or not be feasible due to unusual circumstances that are not applicable to the broader source category that the EPA considered when determining the BSER."). In a more specific example, the Supplemental Proposed Rule asserts that, where EPA estimated that the cost-effectiveness of the wet seal centrifugal compressor emission standard to be $711 per ton of methane removed, to demonstrate unreasonable cost, a State would have to determine that for an "affective facility in their state, the cost effectiveness was <u>$71,000 per ton</u> of methane removed." 87 Fed. Reg. at 74,820 (emphasis added). The notion that States can only justify unreasonable costs by demonstrating, to EPA's satisfaction, that cost-effectiveness will be <u>two orders of magnitude higher</u> than the BSER estimate has no basis in the statute, is patently arbitrary and capricious, and would effectively preclude any State from ever establishing emission limitations based on methods that Congress authorized under Section 111(d). The Supplemental Proposed Rule protests that it only provided the example "for illustrative purposes" and that States do not necessarily need to demonstrate that costs will "be two orders of magnitude higher than the presumptive standard to be considered unreasonable." 87 Fed. Reg. at 74,820. However, this is the only example that the Supplemental Proposed Rule provided using a cost-effectiveness comparison. Both EPA and courts could refer back to this example as indicating that EPA's interpretation of "unreasonable costs" should require a cost difference so extreme that even four or five times the BSER cost-effectiveness (*i.e.*, approximately $2,850 to $3,550 per ton of methane removed) would not be enough to be "unreasonable."

2. *The Proposed Standard for How States Account for Remaining Useful Life Misunderstands Section 111(d) and Lacks a Record Basis*

Further, the very premise underlying EPA's claimed need for standards dictating how States account for a facility's remaining useful life is incorrect. Nothing in Section 111(d) indicates that Congress intended for individual State considerations to avoid "inconsistent application … across states." 87 Fed. Reg. at 74,821. Yet, EPA bases its proposal on the unsupported notion that States must mimic the process EPA uses in establishing emission guidelines. Hence, EPA proposes to compel each State to include "a source-specific BSER for the designated facility" that considers the same five factors used by EPA, and "must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the" emission guidelines and the resulting "standard must be in the same form (*e.g.*, numerical rate-based emission standard) as required by the EG OOOOc presumptive standard." *Id.* States must also provide analyses of why less stringent emission limitations do not "undermine the control objectives of the EG and CAA section 111(d) itself" and document "the time needed to purchase and install equipment required to comply, the time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance, the expected window of time needed to obtain approvals of outside agencies, the time needed to conduct any required community outreach or public hearings, as well as other potential factors." *Id.* at 74,822.

Yet, the Supplemental Proposed Rule provides no legal or record basis for any of these demands. Rather, EPA simply assumes that consistency in both process and results is demanded by Section 111(d). That is directly contrary to the "cooperative-federalism design of Section 7411(d)" that "gives the States broad discretion," *American Lung Association*, 985 F.3d at 962, and would reduce States to clerks performing paperwork exercises dictated by EPA. Further, EPA's statement that its proposed process would "generally address all relevant information that states would reasonably consider in evaluating the emission reductions reasonably achievable for a designated facility," 87 Fed. Reg. at 74,821, is not supported by any record evidence. In fact, there is no discussion of the processes that States actually have used in setting existing source standards for any source categories. Thus, the Supplemental Proposed Rule declares that greater regulation of State analytical processes is required without any evidence of what States have done in the past, whether States have actually arrived at inconsistent results, and if so, that the inconsistencies are undesirable in some way. Instead, the Supplemental Proposed Rule seeks to establish standards based upon hypothetical scenarios and unsupported presumptions. Such an approach is clearly arbitrary and capricious.

3. *Section 111(d)(1) Prohibits the Proposed "Capital Investment" Limitations to the Remaining Useful Life Analysis*

EPA's restriction on consideration of cost is likewise unsupported and contrary to the CAA. The Supplemental Proposal "proposes that the only cost factor that" States should be permitted to "consider in a remaining useful life determination of cost unreasonableness is whether there is a significant capital investment required to design, purchase, and install equipment." 87 Fed. Reg. at 74,823. Under this standard, "EPA does not believe that all types of designated facilities should be eligible for a determination of unreasonable costs associated remaining useful life." *Id.* Therefore, according to the Supplemental Proposed Rule, only "oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps" would be eligible for a State's consideration of remaining useful life and a "cost unreasonableness determination would not be allowed for any other designated facility types." *Id.*

Yet, EPA does not identify any legal authority for such a requirement. Indeed, Section 111(d)(1) expressly prohibits the proposed requirement: "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source … to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies." 42 U.S.C. § 7411(d)(1) (emphases added). With respect to the State's consideration of remaining useful life, this language is unconditional and unlimited. The State may consider the remaining useful life of "any particular source" or any "existing source." The only limitation is placed on the Administrator, not the States. The Administrator "shall permit" the consideration of any source's remaining useful life without any suggestion that Congress granted the Administrator the discretion to constrain the States.

4. The Proposed "Contingency Requirements" Lack a Legal or Record Basis

The Supplemental Proposed Rule also proposes "contingency requirements" that would effectively convert a State's determination that applying emission guidelines to a facility is not reasonably cost-effective into a binding permit term. Two such examples provided in the Supplemental Proposed Rule would be that, (1) if low oil prices would make application of the emission guidelines to a facility unreasonably expensive then a federally enforceable permit conditions would require the facility to shut down if oil prices increased (making the emission guidelines more cost effective), 87 Fed. Reg. at 74,821-22, and (2) if a short remaining useful life makes application of the emission guidelines unreasonably cost-effective, then the facility's retirement date must become a federally enforceable permit condition requiring it to shut down on that date. *Id.* at 74,822.

We again urge EPA to reconsider this approach. Nothing in the statute authorize these restrictions on defining the implementation of RULOF – and none is cited in the proposal. Nor does the record for the proposal indicate that such conditions have been used or would be needed. These "contingency requirements" address purely hypothetical scenarios without any consideration of what States actually have done in setting emission limits under Section 111(d). In addition, EPA previously rejected the requirement to make a facility's retirement date a federally enforceable permit condition, 87 Fed. Reg. at 74,823, in a similar circumstance. Under the 2005 Regional Haze Rule, EPA rejected a commenter's request that, "to the extent that assertions regarding a plant's remaining useful life influences the BART decision, there must be an enforceable requirement for the plant to shut down by that date." 70 Fed. Reg. 39,104, 39,127 (July 6, 2005). EPA rejected the request, explaining that the Clean Air Act would require such a plant to either shut down at the retirement date, face an enforcement action, or install BART controls. In other words, the facility would be able to adapt to any changes in condition. The Supplemental Proposed Rule not only changes EPA's position on this issue, but does so without explanation or even a recognition that it is changing its position.

5. The Proposed Health and Welfare Components of State Emission Limitations Have no Legal or Record Basis and are Impermissibly Vague

The Supplemental Proposed Rule imposes several additional demands on States related to impacted communities. 87 Fed. Reg. at 74,824. These include requiring States "to consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions," implement "meaningful engagement requirements," and "describe the health and environmental impacts anticipated … along with any feedback the state received during meaning engagement." *Id.*

The protection of communities EPA and States find are impacted is an important policy goal, but not one that EPA is authorized to require States to address as part of a State's consideration of RULOF. The text of Section 111(d)(1) speaks only of a State's "consideration" of "the existing source to which such standard applies." Congress did not require or authorize any other considerations, such as impacts to health or welfare – impacts that Congress frequently included in various Clean Air Act analyses when it chose to do so. *See*, *e.g.*, 42 U.S.C. §§ 7408(a)(1)(A) (identifying air pollutants "anticipated to endanger public health and welfare"); 7409(b)(1) (establishing air quality standards "requisite to protect the public health"); 7411(b)(1)(A) (Administrator will publish list of air pollutant emission sources "which may reasonably be anticipated to endanger public health or welfare"). Section 111(d) is specific as to what States may consider ("among other factors, the remaining useful life of the existing source") and never compels States – through words like "shall" or "must" – to consider anything at all. Had Congress intended to direct States to consider generalized "overall health and welfare objectives" in Section 111(d) it would have done so. *Morales v. Trans World Airlines, Inc.*, 504 U.S. 374, 384 (1992) (""commonplace of statutory construction that the specific governs the general.")

In addition, the record EPA has proffered here does not support the specific mandate that EPA would impose on States through this regulation.

First, the Supplemental Proposed Rule declares that these new requirements are necessary "[i]n order to address the potential exacerbation of health and environmental impacts to vulnerable communities as a result of applying a less stringent standard." 87 Fed. Reg. at 74,824; *id.* ("such standards have the potential to result in disparate health and environmental impacts"); *id.* ("communities could be put in the position of bearing the brunt of the greater health and environmental impacts"). EPA has not, however, offered data or analysis regarding the likelihood of any designated facility, or group of designated facilities, of impacting the health of any vulnerable community or the extent of any such potential impacts. Therefore, there is no record basis supporting the proposal.

Second, the proposed regulatory text is significantly different in several important respects from the preamble explanation providing the supporting rationale. The proposed regulatory text requires a State to demonstrate that the "increased emissions for the duration of the remaining useful life will not result in negative impacts to the surrounding communities, including those most affected by and vulnerable to the health and environmental impacts of the plan." Proposed Section 60.5365c(e)(1)(vii). Again, EPA and States may choose to conduct this type of analysis that may offer significant data for the government to consider in fashioning policy, but this language is significantly problematic here in the following respects:

- The State must make some demonstration that the facility's remaining life emissions "will not result in negative impacts to surrounding communities." The preamble at 87 Fed. Reg. at 74,824 supports this requirement by claiming it only requires States to "consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility." The proposed language does not define a "negative impact" or explain what a State must demonstrate. Neither the preamble nor the proposed regulatory language describe how a State may satisfy EPA that these emissions are acceptable.

- The preamble claims that States must analyze emissions for vulnerable communities, which are not defined. *Id.* The proposed regulatory language requires a much broader analysis; one that includes all "surrounding communities." Neither the preamble nor the proposed regulatory language define "surrounding communities," so as proposed, States will have no way of knowing how far their analysis must go.

- The need to provide some analysis of emissions, presumably including their concentration and dispersion, over the facility's remaining life implies that some form of air modeling will be required. For many sources this will be a significant burden layered onto the additional burdens of these regulations imposed on sources and State regulators. However, for other designated facilities, which may include individual pieces of equipment, such as a pneumatic controller, neither the preamble nor the proposed regulatory language provides any indication of what kind of demonstration EPA is expecting.

Therefore, the Supplemental Proposed Rule provides a defective rationale for one set of health and welfare requirements while actually proposing regulatory language that would impose very different requirements. The requirements in the proposed regulatory language are never explained and, therefore, lack the necessary "reasoned explanation." *See*, *e.g.*, *Amer. Wild Horse Preservation v. Perdue*, 873 F.3d 914, 920 (D.C. Cir. 2017) (the APA "mandates that" agencies "give reasoned explanation for the actions that they do take"). And, finally, "[e]lementary administrative law norms of fair notice and reasoned decisionmaking demand that" an agency define what it requires of regulated parties. *Checkosky v. SEC*, 139 F.3d 221, 224 (D.C. Cir. 1998). Here, the proposal (whether that be the Supplemental Proposed Rule's preamble or the proposed regulatory language) does not define key terms ("vulnerable communities," "surrounding communities," "those most affected by and vulnerable to the health and environmental impacts of the plan," "negative impacts"), the type of analysis required, such as air modeling or some unspecified qualitative analysis, or what a State must demonstrate to EPA in order to obtain approval. Therefore, even if EPA had the legal authority to impose these requirements, they lack record support, are unexplained, impermissibly vague, and otherwise arbitrary and capricious.

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GPA Midstream appreciates the opportunity to submit these comments and is standing by to answer any questions you may have.

Respectfully submitted,

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