February 13, 2023

Submitted via www.regulations.gov

The Honorable Michael S. Regan
Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: ***Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (RIN 2060-AV16)*** **Docket ID No. EPA-HQ-OAR-2021-0317**

Dear Administrator Regan:

The American Exploration and Production Council (AXPC) appreciates the opportunity to provide input on the Environmental Protection Agency's (EPA) publication, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Supplemental Proposal") published on December 6, 2022 (87 Fed. Reg. 74,702). AXPC appreciates the importance of regulating methane emissions and looks forward to continuing the robust and productive dialogue with EPA on the oil and natural gas regulations that has been occurring over the past decade.

AXPC is a national trade association representing 32 leading independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in good-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of ensuring positive environmental and public welfare outcomes and responsible stewardship of the nation's natural resources. The United States is a world leader in oil and natural gas production, achieving that status while at the same time substantially reducing emissions. The historic reductions in US greenhouse gas (GHG) emissions over the last decade have been driven by the emergence of US natural gas production as a low-cost source of reliable energy. It is important that regulatory policy enables us to build on that success. AXPC members support continued progress on both fronts through innovation and collaboration.

AXPC companies are focused on reducing methane emissions from their operations and support effective and reasonable regulation of methane that balances the essential value of USUS oil and natural gas production with the global challenge of addressing climate change. AXPC companies believe collaboration amongst policy makers and industry partners is needed to find solutions that will meaningfully drive down emissions, while allowing USUS independent producers to meet the global demand for affordable and reliable oil and natural gas.

Regulation of methane emissions should:

- Encourage innovation and flexibility, instead of narrowly defined requirements that effectively limit technological advancements, hindering the goal of reducing methane emissions;

- Allow and incentivize the development and deployment of technologies to monitor and mitigate methane emissions for compliance purposes;
- Appropriately quantify and assess the feasibility, costs, and benefits of implementing new requirements for existing facilities;
- Avoid creating duplicative and overlapping regulatory regimes at the federal and state levels; and
- Properly interpret and follow the relevant provisions of the Clean Air Act.

Consistent with these principles, AXPC remains supportive of EPA, in keeping the efficiencies in Part 60 of Title 40 of the *Code of Federal Regulations*, Subpart OOOOa, that EPA intends to retain, as reflected in the Supplemental Proposal. These efficiencies reduce unnecessary burden without negative environmental impacts – thus increasing the cost-effectiveness of the OOOOa rulemaking.

AXPC is also supportive of EPA's continued support for the use of emerging technologies that could enhance detection of emissions from the oil and natural gas sector. There are significant new technologies that have been developed over the past six years that are being, or have the potential for being, utilized in the oil and natural gas sector effectively and efficiently. AXPC appreciates EPA's response to industry comments, including AXPC's, requesting that EPA consider a matrix approach for alternative leak detection. AXPC believes EPA's proposed matrix is a step in the right direction. However, as AXPC discusses in its comments, EPA's alternative leak detection program requires critical revisions before operators could utilize it as a viable alternative to traditional inspection methods. AXPC also supports the American Petroleum Institute's more extensive comments on this issue.

While AXPC is supportive of many aspects of the Supplemental Proposal as drafted, AXPC is concerned with the technical feasibility and cost-effectiveness of some provisions that EPA, in the Supplemental Proposal, indicates it intends to finalize or otherwise solicit comment on. AXPC provides specific details with regard to these concerns in the attached detailed comments.

AXPC again urges EPA to provide that the date for determining whether sources are "new" under OOOOb is not November 15, 2021 (the date of publication in the *Federal Register* of the initial notice, which contained no rule text), but rather the date of publication of the Supplemental Proposal – *i.e.*, December 6, 2022, which is when EPA first provided regulatory text for OOOOb and OOOOc. There are a number of proposed requirements in the Supplemental Proposal that were not readily discernible from the November 2021 Notice, in some cases not even conceptually referenced in the 2021 Notice, making the 2021 date inappropriate for applicability – both legally and from a policy perspective. AXPC provides further support for this position in the attached comments.

AXPC is providing detailed comments in the attachment that expands on these general themes as well as many other matters. AXPC appreciates the opportunity to provide these comments and looks forward to working with EPA in its continued development of these rules.

Sincerely,

Wendy Kirchoff

Wendy Kirchoff
Vice President, Regulatory Affairs
American Exploration and Production Council (AXPC)

Attachment: AXPC Specific Comments

AMERICAN EXPLORATION & PRODUCTION COUNCIL

AXPC SPECIFIC COMMENTS
TABLE OF CONTENTS

AXPC Specific Comments on EPA's Supplemental Notice of Proposed Rulemaking: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Docket ID No. EPA-HQ-OAR-2021-0317

I. Policy/Overarching Comments

Throughout these comments, we refer to the Environmental Protection Agency's (EPA) November 15, 2021 initial notice[1] as the "November 2021 Notice" and to EPA's December 6, 2022 supplemental proposal[2] as the "Supplemental Proposal." For ease of drafting, we may refer to only NSPS OOOOb, but unless otherwise noted or inapplicable, we intend for comments with respect to NSPS OOOOb to apply also to Emissions Guidelines (EG) OOOOc.

In our December 9, 2022 letter, we explain in great detail why it would have been appropriate for EPA to have provided more than 69 days that spanned three major holidays for commenting on the Supplemental Proposal. The comment period also overlapped with the Bureau of Land Management's proposed rule, "Waste Prevention, Production Subject to Royalties, and Resource Conservation" (87 Fed. Reg. 73,588), which taxed the limited resources of many AXPC members as they also prepared comments for this Supplemental Proposal. As noted in our letter, the voluminosity of the Supplemental Proposal alone certainly warranted more time for comment, but EPA was unpersuaded by our request and the many other requests it received. Accordingly, AXPC has attempted to respond to as many of EPA's requests for comment as possible, but AXPC could not cover all of EPA's requests in the limited time given for comment, nor could AXPC address all potential concerns and issues raised by the Supplemental Proposal.

I.A. NSPS OOOOb and EG OOOOc should not regulate non-emitting equipment or activities.

For several affected/designated facility definitions, EPA includes equipment that is not designed to emit to atmosphere in contradiction of the Clean Air Act (CAA) – pneumatic pumps, pneumatic controllers, and gas well liquids unloading operations. For these equipment and activities, EPA proposes the following best system of emission reduction (BSER):

- Pneumatic controllers: Design and operate each pneumatic controller with zero VOC emissions and/or methane emissions, excluding Alaskan pneumatic controllers which we do not address in these comments.[3]

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[1] 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. 63,110 (Nov. 15, 2021).

[2] 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. 74,702 (Dec. 6, 2022).

[3] Proposed 40 C.F.R. §§ 60.5390b(a), .5394c(a) (Document ID No. EPA-HQ-OAR-2021-0317-1551 and Document ID No. EPA-HQ-OAR-2021-0317-1552) (hereinafter referred to as "Proposed" regulation without further reference to the docket).

- Pneumatic pumps: Install and operate pneumatic pumps that are not powered by natural gas.

- Gas well liquids unloading: Operators must conduct unloading operations with zero emissions to atmosphere.

In each case, EPA's proposed BSER is to have no emissions to atmosphere. And for these non-emitting equipment or activities, EPA imposes burdensome recordkeeping and reporting requirements that have no corresponding environmental benefit. This exceeds EPA's authority under the Clean Air Act.

The issue here is whether CAA § 111(b) and/or (d) authorize EPA to set performance standards that ensure the intended regulatory target is not a "stationary source." The CAA's standards of performance – both §§111(b) and (d) – provide EPA authority to regulate categories of "stationary sources," and define a stationary source as "any building, structure, facility, or installation which emits or may emit any air pollutant."[4] This plain language of the statute requires that a stationary source emit, or have the potential to emit, to atmosphere. While "stationary source" may apply as broadly as an entire well site, for example, EPA's historic implementation of §111(b) has been to more narrowly regulate "affected facilities" – typically a type of equipment or activity – which AXPC believes fits within §111's definition of stationary source. Given the statute's plain language, it is outside of EPA's authority to regulate non-emitting equipment or activities under §111 because any such equipment or activity is not a "stationary source."

Here, EPA proposes BSER that would result in no VOC or methane emissions from pneumatic controllers, pneumatic pumps, or gas well liquids operations. Thus, compliance with EPA's proposed BSER ensures that pneumatic controllers, pneumatic pumps, and gas well liquids operations are not "stationary sources" because compliance will not, and could not, result in emissions. This exceeds EPA's authority granted under §111.

Consistent with the CAA, **AXPC requests that EPA define the NSPS OOOOb pneumatic controller and pneumatic pump affected facilities as equipment designed to emit VOC and/or methane and similarly define the EG OOOOc designated facility to include equipment designed to emit methane.** Failing to define the affected/designated facility in this manner would result in the inappropriate imposition of onerous recordkeeping and reporting requirements on equipment that is not a stationary source.

For gas well liquids unloading operations, AXPC requests that EPA remove the zero emissions standard and associated recordkeeping and reporting requirements such that OOOOb/c standards apply only where the operator intends that a gas well liquids unloading operation result in methane and/or VOC emissions to atmosphere.

AXPC's proposals above will result in no additional emissions, as:

- Natural gas-driven pneumatic controller systems routing to process would be subject to the requirements applicable to the collection of fugitive emissions components affected/designated facility standards. AXPC proposes below that EPA include routing to a control device as a compliance standard, in which case the pneumatic controller vent gas

[4] 42 U.S.C. § 7411(a)(3) (emphasis added).

would result in controlled emissions to atmosphere with the pneumatic controller being an affected/designated facility subject to NSPS OOOOb or EG OOOOc standards.

- Similarly, the proposed pneumatic pump affected facility has standards that would apply where a pneumatic pump is intended to emit to atmosphere, and excluding those pneumatic pumps that are designed to not emit to atmosphere would result in no additional emissions and significantly reduce the operators' administrative burden. And excluding this non-emitting equipment from OOOOb/c requirements serves as an incentive to install non-emitting equipment, while having no impact on the proposed standards that apply to emitting pneumatic pumps.

- Like pneumatic pumps, the gas well liquids unloading standard is a zero emissions standard, and EPA proposes standards applicable to unloading operations with emissions to atmosphere. Excluding non-emitting gas well liquids unloading activities from regulation would not impact the standards for those unloading events that emit to atmosphere.

I.B. Best System of Emission Reductions (BSER) opt-out should include economic factors in addition to technical feasibility or safety.

EPA concedes that it is proposing multiple regulatory requirements whose implementation would be so burdensome that they would be "technically infeasible" for some set of affected facilities. EPA thus gives affected facilities the ability to "opt out" of the performance standard if the affected facility can show that compliance with the performance standard would be infeasible for technical or safety reasons. As explained below, "technically infeasible" is a misnomer and EPA should explicitly include economic factors in addition to a technical feasibility analysis.

Within EPA's OOOOb/c regulations, EPA provides opt out for their regulatory requirements such as the ability to use an emissions control device to handle associated gas,[5] the continued use of pneumatic pumps driven by natural gas,[6] and the use of emitting gas well unloading methods.[7] In Section II.D.i of these Comments, AXPC provides at least one additional recommendation of an opt out with respect to pneumatic controllers. Unfortunately, EPA does not provide any information within the rule on how an affected facility is expected to demonstrate that the regulatory provision in question is "technically infeasible" in their case, other than a requirement that a professional engineer or other qualified individual so certify.

Because there is no explanation of technical infeasibility within the rulemaking, we evaluated what EPA has done in other Clean Air Act (CAA) programs. For example, EPA's regulations related to best available retrofit technology (BART) determinations under the regional haze program include some insight into how EPA might evaluate technical feasibility considerations.[8] According to EPA's BART regulations:

> Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2)

[5] *See, e.g.*, Proposed § 60.5377b(b)(2).
[6] S*ee, e.g.*, *id.* § 60.5393b(c).
[7] S*ee, e.g.*, *id.* § 60.5376b(c)(2)(ii)(B)(2).
[8] *See* 40 C.F.R. Part 51, Appendix Y.

> the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.[9]

While these regulations provide more context than EPA's proposed OOOOb/c regulations, the BART regulation conflates economic factors and technical feasibility and does not specifically account for other factors related to potential implementation that may be critical to compliance. The "available" concept is inherently an economic concept as it relates to whether the item is commercially available – *i.e.*, that the price is at such a level that it can be produced commercially. If EPA was truly looking at considering technical feasibility without regard to economic viability, whether a technology is commercially available would be irrelevant. And to do so here, would be inappropriate, particularly given the definition of standard of performance. Under CAA § 111(a)(1), standard of performance means

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator deems has been adequately demonstrated. [10]

By providing an opt-out, EPA inherently recognizes that BSER cannot be met at every facility. Thus, in making the demonstration that use of the opt out is appropriate, the costs of achieving such emissions reduction should be taken into account.

Further, because EPA may only include standards that are determined to be adequately demonstrated, technical feasibility for the opt-out provisions in NSPS OOOOb/c, technical feasibility must include considerations such as: ability to access electrical power; landowner access; other local or state regulatory requirements; and other considerations that limit the ability to comply with the standard of performance. In other words, technical feasibility must include considerations beyond just physical impossibility. Anything that would preclude or hinder implementation of the regulations should be included in a consideration of feasibility – whether technical, economic, or some other appropriate consideration. However, EPA should be explicit that economics is to be considered in the feasibility analysis – as technical feasibility alone is insufficient.

We discuss the specific concept that commercially unavailable technologies should not be considered technically feasible in further detail with respect to EPA's proposed oil well associated gas standards in Section II.A.iii of these Comments.

Instead of EPA conflating technical feasibility and economic considerations, as it does in the Supplemental Proposal, EPA in its final rule should transparently state that economic factors must be part of an affected facility's ability to opt out of the regulatory requirement, in addition to whether installation and operation of the regulatory requirement is technically feasible and safe.

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[9] *Id.* Appendix Y(D)(1).
[10] 42 U.S.C. § 7411(a)(1).

We therefore recommend that EPA adopt the following general standard for opting out of EPA's performance standards or apply this type of standard in instances where EPA has provided an opt out.

An affected facility may opt out of the standard of performance if any of the following apply:

- The performance standard cannot reasonably be installed and operated at the affected/designated facility including due to technical feasibility, safety concerns, or physical impossibility;

- The cost of compliance with the performance standard would result in the affected/designated facility having a cost-effectiveness greater than $5,540 per ton of VOCs or $1,970 per ton of methane or the well is no longer able to economically operate; or

- The cost of compliance with the performance standard would be so great that it would result in the affected/designated facility no longer being able to economically operate.

In addition to the general standard provided above, EPA should provide detailed information on what affected facilities can show to meet the requirements for opting out of a control requirement.

I.C. <u>EPA should extend implementation timelines – particularly for sources that became NSPS OOOOb affected facilities prior to the date of final rule publication.</u>

For facilities that became new, modified, or reconstructed after the NSPS OOOOb "new" facility trigger date – November 15, 2021, as proposed by EPA; and December 6, 2022, as requested by AXPC – and before the final rule's federal register publication date, AXPC urges that EPA provide additional time to come into compliance following the final rule's effective date for certain affected facilities. Until the effective date of NSPS OOOOb, some of these facilities would be unregulated under an existing NSPS or would begin operating as NSPS OOOOa affected facilities and may then need to complete retrofits to comply with newly applicable NSPS OOOOb standards. For example, NSPS OOOOa pneumatic controllers and pumps are not subject to a zero emissions standard but would be subject to zero emissions standards under NSPS OOOOb, requiring retrofit within 60 days of the final rule's publication in the Federal Register. This is not enough time to acquire retrofit equipment that will be in high demand, and likely short supply, as operators across the country place orders for equipment to meet the zero emissions standard. In addition, operators must acquire engineering resources to engineer the installation of zero emissions pneumatic controller systems. These engineering resources, too, are likely to be in high demand and short supply.

The timing of compliance obligations is particularly pronounced for pneumatic pumps. For this equipment, EPA now proposes that operators may no longer utilize pneumatic pumps that are driven by natural gas, subject to limited exceptions. EPA's November 2021 Notice did not go so far as to eliminate the use of natural gas-driven pneumatic pumps entirely. This means operators may need to completely replace natural gas-driven pneumatic pumps that would have complied with the standards described in EPA's November 2021 Notice. As EPA notes in the Supplemental Proposal, the move to eliminate natural gas-driven pneumatic pumps "is a significant change from the November 2021 proposal."[11] We agree.

[11] 87 Fed. Reg. at 74,770.

Similarly for storage vessels, unless and until NSPS OOOOb is a final rule, those storage vessels that commenced construction, modification, or reconstruction after November 15, 2021 ("NSPS OOOOa/b Vessels"), are subject to NSPS OOOOa, which has a different applicability threshold than NSPS OOOOb. Under NSPS OOOOa, requirements apply to *individual* storage vessels with the potential for VOC emissions of six tons per year (tpy) or more. NSPS OOOOb uses the "cumulative emissions from all storage vessels within the tank battery," while using the same six tpy potential for VOC emissions threshold and the new 20 tpy methane threshold. This switch to a storage tank battery approach effectively reduces the storage vessel affected source threshold, meaning the same NSPS OOOOa/b Vessel may not be an NSPS OOOOa affected facility but will be an NSPS OOOOb affected facility if the applicability criteria remain the same in the final NSPS OOOOb. For these NSPS OOOOa/b Vessels, an onerous suite of new requirements will become applicable 60 days after publication of the final rule, as drafted in EPA's Proposal. Operators will require more than 60 days' time to implement these requirements. For example, certifying the design of each storage vessel closed vent system could take weeks, and operators will need to hire staff to implement control device monitoring requirements. Additionally, EPA proposes control device monitoring requirements that may require extensive capital investment in equipment likely to be in short supply, as noted in the comments above – *e.g.*, calorimeters. While EPA may argue that operators are on notice of the requirements, the rule is not final and may change in its final form. It is inappropriate and poor policy for EPA to require operators to undertake significant capital investment and personnel hiring for a rule that is not, and may never become, final simply to be in position to comply suddenly with requirements that may be materially different in the final rule.

EPA encountered similar issues for storage vessels under NSPS OOOO. In that rulemaking, EPA recognized the infeasibility of compliance for storage vessels constructed following proposal and before publication of the final rule and provided an additional year for those storage vessels to comply. EPA should do the same here for pneumatic controllers and pumps. **AXPC proposes that EPA extend the initial compliance deadline for pneumatic controllers, pneumatic pumps, and storage vessels at least one year for those affected facilities that became NSPS OOOOb affected facilities between the "new" trigger date and the date the final rule is published in the Federal Register.**

In addition to pneumatic controllers and pumps, EPA proposes entirely new net heating value (NHV) monitoring requirements for combustion control devices, in addition to flow monitoring that will cover many more control devices than under current rules. At least for NHV monitoring, this could not have been anticipated, and NHV and flow monitoring equipment and the resources to engineer and install it will be in high demand and short supply. As noted in Section II.F.ii.b of these Comments, AXPC believes that NHV monitoring of oil and gas equipment vent streams is unnecessary. EPA also proposes enclosed combustion device performance testing requirements, that while similar to NSPS OOOO and OOOOa, will require significantly more testing under NSPS OOOOb and EG OOOOc. The expanded scope of coverage of performance testing requirements will increase demand significantly, and likely well above the current testing resource supply. It will take at least one year, and likely longer, for performance testing vendors to acquire additional testing equipment and hire and train new personnel to meet the unprecedented demand. Accordingly, **AXPC proposes that EPA extend the initial compliance deadline for all combustion control device monitoring and performance testing requirements by at least one year.**

Alternatively, if EPA is unwilling to provide extended initial compliance deadlines as requested above, AXPC requests that EPA provide extensions where good cause exists, as it did under the recently promulgated Uintah and Ouray Indian Reservation FIP for oil and natural gas sources.[12]

I.D. Legally and practicably enforceable limit definition should be set aside unless and until EPA completes a national rulemaking.

EPA proposes to define what is a legally and practicably enforceable limit for purposes of determining the potential for VOC and methane emissions from storage vessels. The concept of a legally and practicably enforceable limit is not limited to NSPS OOOOb/c storage vessels though, and its finalization will create much uncertainty across Clean Air Act (CAA) programs, as other sources wonder whether EPA's newfound definition will apply in other contexts – *e.g.*, New Source Review (NSR) permitting or §111 performance standards for other source categories. **We urge EPA to delay taking final action on the proposed legally and practicably enforceable limit definition unless and until EPA undertakes a broad-based rulemaking that would provide a single consistent approach across all affected CAA programs.** This approach would avoid many potential inconsistencies and uncertainties across CAA programs and, if EPA proceeds with a national approach, allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

I.E. Demarcation date for NSPS OOOOb new, modified, and reconstructed sources should be December 6, 2022.

AXPC believes that **EPA should set the demarcation date for new, modified, and reconstructed NSPS OOOOb as December 6, 2022**. In support, AXPC incorporates by reference and supports the comments in Section 12.1 of the American Petroleum Institute's Supplemental Proposal Comments.[13] Briefly, AXPC believes:

- The November 2021 Notice did not meet the bare minimum requirements under Clean Air Act (CAA) § 307(d) and Administrative Procedure Act (ACT) § 553(b) to constitute a "proposed regulation" because a preamble without regulatory text is not a "regulation;" and

- Because the November 2021 Notice was not a "proposed regulation," it could not define a "new source" trigger date under CAA § 111(a)(2).

I.F. EPA must clarify that where overlapping NSPS requirements apply to a source, the source needs to comply with only one set of requirements.

EPA's Supplemental Proposal suggests that existing facilities will be subject to multiple, overlapping NSPS OOOO vintage requirements. This approach will result in a quagmire of uncertainty for the regulated community and implementing agencies alike. In the Supplemental Proposal's preamble, for one type of affected facility, EPA explains how it believes "the proposed EG OOOOc [will] impact

[12] *See* 40 C.F.R. § 49.4169(c).

[13] American Petroleum Institute, Comments on EPA's "Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (Feb. 13, 2023) (hereinafter referred to as "API Supplemental Proposal Comments").

sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa."[14] Generally, EPA suggests that one must conduct a line-by-line comparison of the requirements from each of the multiple applicable regulations to determine which is most stringent, and EPA will consider compliance with the most stringent to be compliance with the other applicable regulations. There will of course be uncertainty as to whether one requirement is more stringent than another. For example, if a similar standard requires methane and VOC reductions on the one hand and only methane reductions on the other, which is more stringent? In addition to this uncertainty, EPA does not explain how operators must sort through the reporting and recordkeeping requirements under multiple standards that would apply simultaneously. Must the operator report under both standards? To date, EPA's explanation of how to deal with these overlapping regulations has been unclear.

Moreover, EPA provides no legal analysis for why it believes a source could be subject to multiple, conflicting performance standards as a "new" source under one standard and an "existing" source under another. AXPC is not aware that EPA has ever taken the position that a source could continue to be subject to a previously applicable new source performance standard after triggering the applicability of a subsequent standard. And here, EPA proposes that EG OOOOc will apply to existing sources regardless of whether the source is subject to NSPS OOOO or OOOOa.

AXPC requests that EPA clearly identify that only one NSPS OOOO/a/b/c standard can apply to a source at any given time. If EPA trudges forward with its current proposal, EPA must provide detailed affected facility-by-affected-facility guidance, on a requirement-by-requirement basis, that clearly identifies the applicable compliance standard, along with guidance on recordkeeping, reporting, and notification requirements. Anything short of this detailed guidance would be an inescapable enforcement trap.

I.G. <u>EPA should not treat existing facilities the same as new facilities.</u>

EPA's proposed regulations provide virtually identical treatment of new sources (regulated directly by EPA under Clean Air Act (CAA) § 111(b)) and existing sources (regulated through a state-planning process under §111(d)). It strains credulity that EPA would determine that the "best system of emission reduction" that has been "adequately demonstrated" for the sources in question, and the resulting standards of performance (for new sources) and presumptive emissions limitations contained in EPA's emission guidelines (for existing sources) would be *exactly the same* across seven different major regulatory requirements, especially considering that new sources are regulated for both volatile organic compounds (VOCs) and methane, while existing sources are only regulated for methane. EPA has not provided sufficient analysis to justify its largely identical treatment of the two types of sources.

CAA § 111(d)(1)(A) provides that EPA prescribe regulations that establish a procedure similar to the §110 program that establishes a "standard of performance" for any existing source. Standard of performance is defined in §111(a)(1) as:

> the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

[14] 87 Fed. Reg. at 74,716-18.

Therefore, EPA must conduct a separate, robust, and transparent BSER analysis for existing sources (at a categorical level) that is meaningfully distinct from its analysis of new sources. While there are references in the preamble to the Regulatory Impact Analysis, which references the Technical Support Document, which then subsequently references Excel sheets, which themselves provide their own references, this maze of references is, at best, opaque and unclear.

EPA's analysis is concerning because it appears to deviate from generally accepted principles on costs for new regulations. Designing a new facility can account for new regulations, whereas existing facilities must rework their system, the costs of regulations are significantly higher on existing facilities than on new facilities. This is especially true for regulatory requirements with significant capital requirements.

This cost principle can even be seen in a parallel provision of the Clean Air Act itself. §112, which regulates hazardous air pollutants, often sets more stringent technology standards for new sources than for existing sources.[15]

Instead of an upfront transparent BSER analysis for existing sources, EPA makes several conclusory assertions within the preamble that the existing source cost-effectiveness for the regulatory provision are the same as the new source cost-effectiveness. For example, for associated gas from oil wells, EPA merely states for existing sources:

> The proposed presumptive standards for associated gas from existing oil wells mirror those described above for NSPS OOOOb. The EPA did not identify any circumstances that would result in a different BSER for existing sources under the EG OOOOc.[16]

This is in stark contrast to the significant amount that is written on the BSER analysis for new sources within the preamble and lacks the sufficient rationale for why BSER is equivalent. It provides no specifics for the public to comment on. This provides insufficient notice to the public. It also disregards an important factor under the statute: the special nature of existing sources, as reflected in Congress' choice to regulate them under a separate provision mediated through a state-planning process. This refusal to take seriously the differences between new and existing sources and their varying abilities to comply with regulations of a given stringency is a serious flaw running through EPA's entire treatment of existing sources in its proposal.

For the regulatory requirements where EPA does provide different cost-effectiveness values (although resulting in the same requirements for new and existing sources), it results in multiple situations where the existing source regulatory requirement is *more* cost-effective than the requirement for the new sources.[17] This seems to defy logic as the costs should be significantly higher for existing sources due to the cost of removing or retrofitting the existing equipment, going through any required local or federal permitting processes (*e.g.*, requiring any additional land), and replacing it with the new equipment or retrofitting existing equipment. Additionally, existing sources may have substantially less production in their remaining life with which to offset the cost of retrofit and successfully make the business case for doing so versus shutting in the well. In these cases where the economics of the new

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[15] *See* 42 U.S.C. § 4712(d)(3).
[16] 87 Fed. Reg. at 74,781.
[17] *Compare, e.g.*, *id.* at 74,762 (Table 25), *with id.* at 74,768 (Table 28).

compliance costs force the well to be shut in, EPA must also consider the costs of that lost production and of stranded reserves.

At the same time, the emissions reductions from the regulatory requirement will often be equivalent between a new and existing source or the emissions reductions from the existing sources (with lower production) will often be lower. Therefore, the cost-effectiveness value – which is the cost of the regulatory requirement divided by the emissions reductions – should be higher for existing sources. It does not seem plausible that an existing source standard could be more cost-effective than a new source, and EPA does not provide any rationale as to why this implausible scenario is occurring.

This means that one (or both) of two things are occurring: (1) EPA is underestimating the true cost to existing sources; or (2) EPA has not undertaken a genuine analysis from the outset of what existing sources are capable of *as* existing sources, distinct from new ones. Either of these explanations means EPA is acting in an arbitrary and capricious manner.

The conflation of BSER analyses between new sources and existing sources is contrary to CAA § 111 and should be revised. **Therefore, EPA must treat existing facilities differently than new facilities—or, failing that, provide an *actual* analysis and transparent explanation subject to public comment as to why it has determined that it is not appropriate to treat them differently.**

I.H. EPA should allow states to make programmatic equivalency demonstrations.

AXPC requests that EPA allow states to leverage existing state programs through submittal of total program evaluations to demonstrate equivalency with EG OOOOc.

Precluding states from making a programmatic equivalency determination – by requiring EPA's source-by-source approach – serves as a disincentive to state rulemaking. Over the past decade, states like Colorado and New Mexico have expended many resources, time, and effort to promulgate new oil and gas regulations covering the same designated facilities as EPA proposes to regulate under EG OOOOc. In fact, EPA's proposal relies in large part upon standards already in place in these states. If EPA requires states to demonstrate equivalency on a source-by-source basis, rather than through a programmatic emissions reduction demonstration, EPA places a one-size-fits all approach to state regulation in contradiction of the cooperative federalism principles inherent throughout the Clean Air Act and specifically enumerated in §111(d). Further, EPA's source-by-source equivalency approach will stifle progressive state rulemaking, as those states would be less likely to expend the significant resources to promulgate new rules only to have EPA swoop in and set aside well-thought state programs.

AXPC requests that EPA allow states to demonstrate equivalency with EG OOOOc standards via a programmatic emissions reduction demonstration.

I.I. RULOF and State Prerogatives Under §111(d)

The text, structure, and context of Clean Air Act (CAA) § 111(d) all show Congress' clear intention: EPA must give the states meaningful discretion and flexibility in how they regulate existing sources in their state plans. EPA's proposal is not consistent with Congress' intent.

§111(d)(1) requires EPA to allow states to assign standards of performance to existing sources that are not one-size-fits-all, top-down requirements, and that take into consideration the particular circumstances of those sources:[18]

> Regulations of the Administrator under this paragraph *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.

There are two obvious policy reasons why Congress provided different treatment for existing and new sources. The first is an economic reason: retrofitting or altering operations at an existing source to comply with regulations is more burdensome, and in some cases impossible, as compared to designing a newly constructed source. The second is a question of policy and the legal framework of the Clean Air Act: Congress knows states are more aware of and better equipped to handle the particular circumstances of their existing-source fleet than EPA. And the text mirrors these policies perfectly – EPA has to let the states apply their knowledge in their development of state plans.

EPA's proposal is inconsistent with the design of the existing source program, and Congress' direction that it allow the states this role. Rather, its proposal adds unnecessary burdens on states' ability to exercise the authority Congress directed EPA to allow them, without statutory justification.

EPA proposes to require a state to engage in additional public engagement and to step into the shoes of the EPA itself by conducting its own, source-specific BSER analysis before it assigns a standard of performance to a particular existing source that is less stringent than what would result from a direct application of the presumptive requirements in EPA's emission guidelines. Congress did not authorize these additional requirements in §111(d). EPA's motive appears to be in direct conflict with what Congress gave the states through their RULOF authority, and instead proposes a program so onerous for states that they will just accept EPA's requirements and avoid the considerable burden that would be required to exercise their express statutory RULOF authority.

Tellingly, EPA requires *no* additional process for a state that wishes to assign a *more* stringent standard of performance to an existing source. EPA has not justified this different treatment – other than by observing that more stringent standards will lead to greater emissions reductions.

§111 is not a maximum-achievable-reductions provision, unlike some other provisions of the Clean Air Act and other environmental statutes. It requires a careful threshold analysis by EPA as to what systems of emissions reductions are "adequately demonstrated" and what reductions are "achievable," and it contains language directing EPA to allow states to vary from EPA's own presumptive standards where particular circumstances warrant. The one-way ratchet created by EPA's split treatment of states confirms its inconsistency with Congress' statutory scheme.

Finally, EPA also disregards the statutory scheme when, in what appears to be the first time ever, it proposes to require that states undergo their own version of a BSER analysis before assigning a less stringent standard to an existing source. BSER occurs only in one portion of §111, in the initial definition of "standard of performance" in §111(a)(1). In that provision, it is explicitly the EPA Administrator's role to determine BSER. In constricting states from being able to fully exercise the authority Congress granted them in §111(d), EPA is blurring the lines, departing from its previously

[18] (emphasis added).

unbroken insistence that BSER is a matter for the EPA, and confusing two distinct roles which could not be clearer under the text and structure of the statute.

Congress' design for existing-source regulation is quite clear. EPA should determine what reductions existing sources as a categorical matter can be expected to achieve (taking into account whether and how existing sources differ in this regard from new ones).

EPA directly regulates new sources. But *states* set standards of performance for their existing sources in their state plans, with the authority to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." EPA's attempt would impose extra hurdles and blur clear statutory lines which is not in keeping with Congress' design. EPA has no authority to impose these requirements, and certainly does not have authority to reject a state plan as not being "satisfactory" for failure to comply with them.

I.J. <u>EPA's §111(d) Self-Imposed Deadlines for EPA's Review of State Plans/Issuance of a Federal Plan</u>

As a preliminary matter, we acknowledge that EPA in the Supplemental Proposal did not propose deadlines for the EPA's own functions as part of the §111(b) existing-source regulatory process.[19] We intend to submit comments on EPA's separate proposal, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 87 Fed. Reg. 79,176 (Dec. 23, 2022), whose comment period closes on February 27, 2023, in which we will address EPA's proposed deadlines. However, because, reading the terms of the two proposals together, some of the deadlines proposed in that separate proposed revision to the "implementing regulations" generally governing EPA's administration of the existing-source program will apply to proposed new EG OOOOc, we are presenting our observations, concerns, and suggestions on these proposed deadlines as part of these comments as well. We also note that we provide the comments in this Section I.J based in part on AXPC's proposals and interpretations regarding the Inflation Reduction Act (IRA) as further described in Section I.K below. In other words, AXPC does not believe that EPA will delay its ability to make determinations that the conditions for exemptions from the methane fee program under the IRA are met by providing itself sufficient time to make completeness determinations and approve state programs under EG OOOOc.

These comments here are directed to EPA's intention to apply certain deadlines proposed in the "implementing regulations" proposal to EG OOOOc.[20] Due to the overlapping comment periods and the interrelated nature of the two proposals, we feel it is better to file partially redundant comments on the two proposals rather than risk raising the comments in an incorrect forum.

Our general observation on EPA's proposed deadlines is that, when EPA imposes deadlines on itself to perform functions to which Congress assigned no statutory deadline, EPA is creating new

[19] *See* 87 Fed. Reg. at 74,831-33.
[20] *See id*. (EPA intends to apply some deadlines proposed in the separate "implementing regulations" proposal to Subpart OOOOc and intends to finalize the "implementing regulations" proposal "not later than" it finalizes Subpart OOOOc).

obligations on itself which are potentially enforceable under "deadline" suits brought by outside parties under Clean Air Act § 304.[21]

If EPA imposes deadlines on itself that are not long enough, it runs the risk of the timing and prioritization of its tasks being set not by itself or by Congressional direction, but rather by litigation brought by outside interest groups. The experience of the National Ambient Air Quality Standards (NAAQS) program and its associated state- and federal-planning process, replete with statutory deadlines as it is, is a cautionary example: where deadlines cluster, and where EPA has to respond to many state submissions subject to those deadlines, or take state-by-state action on its own subject to other deadlines, many or most deadlines will not be met in the first instance, will be subject to "deadline suit" litigation, and will end up with new deadlines imposed via settlement or court order – often out of control of EPA and the states, or at a faster pace than is appropriate.

This familiar scenario in cases where Congress *has* imposed statutory deadlines is more reason for EPA to ensure that it gives itself adequate time when selecting deadlines of its own choosing. This concern is especially pressing in this rulemaking, which will initiate the most complicated existing-source implementation process EPA has yet managed in over 50 years of administering the Clean Air Act, with most if not all states containing jurisdictional existing sources requiring a §111(d) plan, and many states containing an unusually high number (thousands or more) of existing sources that are unusually complex and variegated—as EPA forthrightly acknowledges in the Supplemental Proposal.[22]

We recommend EPA finalize a mechanism under which a state can ask for and receive an extension of their submittal deadline if the state demonstrates to the Administrator that its situation is sufficiently complex or otherwise unique that the general assumptions, findings, or rationale underlying the deadlines that EPA does finalize do not apply in its case. EPA should also consider finalizing such a mechanism to provide itself with an extension for its own deadlines to make completeness determinations, decisions to approve or disapprove submitted state plans, and to issue federal plans where special circumstances warrant. However, these extension mechanisms would not be advisable if they required an additional round of notice-and-comment rulemaking, as that would divert additional EPA resources from working with states on their plan development, submittal, review, and approval.

If EPA does not adopt this type of extension mechanism, we recommend the following specific changes to the deadlines proposed at 87 Fed. Reg. 79,182, Table 1 as they will apply to final Subpart OOOOc:

- **Where EPA proposes two months for EPA to determine whether a state plan submittal is complete, we urge the agency to provide itself with no less than four months. Two months is an unusually short deadline in the context of the complexity of the task before EPA and the high number of state plan submittals EPA is likely to receive – all likely clustered around the deadline for submission of such plans. The proposed two-month deadline is particularly likely to create a "logjam" scenario of missed deadlines at the outset of the state-plan review process, accompanied by a heightened risk of diversion of resources to "deadline suits" as described above.**

[21] *See, e.g.*, *California v. EPA*, 360 F. Supp. 3d 984, 991 (N.D. Cal. 2018) (Congress intended in Section 304 "to waive sovereign immunity for the EPA's failure to perform nondiscretionary duties mandated by regulations").
[22] *See generally*, 87 Fed. Reg. at 74,832-34.

- **Where EPA proposes 12 months for EPA to issue a federal plan after disapproving a state plan or determining that a state has failed to submit a complete plan, we urge the Agency to provide itself with no less than 18 months. EPA should give itself at least as much time to draw up its plan as it's giving the states to draw up their plans. The Supplemental Proposal explicitly states: "18 months is the *minimum* period of time in which the EPA finds that most states can expeditiously create and submit a plan that meets applicable requirements for EG OOOOc."[23] For the same reason, EPA should provide itself with *at least* that same period of time. EPA indeed may wish to consider providing itself with *more* time than it provides the states, given that the states as local and primary regulators are presumably more familiar with the characteristics of their existing-source fleets than is EPA as a general, federal regulator.**

I.K. Exemption for Regulatory Compliance under the MERP

Because the relevant language of the Inflation Reduction Act (IRA) is ambiguous, and particularly because of the lack of legislative history, we believe that EPA has significant latitude to interpret this language. We believe that EPA should be guided by the overarching goal of *reducing emissions*-- the objective policy outcome, a goal that we all believe in, and in keeping with the title of this section of the IRA.

EPA solicits comment on a number of issues with respect to Sec. 60113 of the IRA, "Methane Emissions Reduction Program" (MERP). EPA's request for comments specifically relate to Sec. 136(f)(6), "Exemption for regulatory compliance." Under this provision, "an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111" is exempt from the MERP's charge obligations if the EPA Administrator determines that:

- Methane emissions standards and plans pursuant to §§111(b) and (d) have been approved and are in effect in all states with respect to the applicable facilities; and
- Compliance with the requirements will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "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. 63,110 (Nov. 15, 2021)), if such rule had been finalized and implemented.[24]

This regulatory compliance exemption also includes a backstop provision, pursuant to which charges are reimposed if the conditions set forth above "cease to apply."[25]

Therefore, AXPC is providing comments on:

- What the EPA Administrator can make a determination on;
- Who can apply for an EPA determination and when they can apply;
- What "in compliance with and subject to" means;

[23] *Id.* at 74,834 (emphasis added).
[24] Inflation Reduction Act § 60113, 136 Stat. 2075, *codified at* 42 U.S.C. § 7436(f)(6)(A), (i), (ii).
[25] *Id.* § 7436(f)(6)(B).

- What "have been approved and are in effect in all States with respect to applicable facilities" means; and
- What "result in equivalent or greater reductions" relative to the November 2021 Notice means.

Our comments do not address how to measure GHGs or compliance assurance under the MERP. These subjects are not within the scope of the Supplemental Proposal, and we anticipate commenting on these subjects in the course of a forthcoming EPA MERP implementation rulemaking. AXPC also reserves the right to comment on the above list of topics during the forthcoming EPA MERP implementation rulemaking.

I.K.i. <u>Scope of EPA Administrator Determinations</u>

According to 42 C. § 7436(f)(6)(A), the "charges shall not be imposed pursuant to subsection (c) on an applicable facility . . . upon a determination by the [EPA] Administrator . . . ." This language does not specifically address the scope of the Administrator's determination.

The most efficient approach would be for the Administrator to make determinations based as to when subject OOOOb is approved (relevant to new, reconstructed or modified affected facilities) and when each state adopts as a matter of state law a state plan pursuant to §111(d) and EG OOOOc (relevant to existing designated facilities). While AXPC is not recommending a specific process at this time, we are providing some examples below for reference.

For sources regulated under OOOOb, when NSPS OOOOb regulation goes into effect, EPA could determine that all such sources subject to NSPS OOOOb are meeting the requirements under §7436(f)(6)(A) and exempt emissions associated with such sources from the methane fee while not yet making a determination for all sources regulated under EG OOOOc.

States A, B, and C with just midstream operations (*e.g*., natural gas processing plants) adopt (as a matter of state law) state regulations or plans pursuant to EG OOOOc, and the adopted state regulations or plans have become legally effective as a matter of state law (irrespective of submission to and timing of EPA approval). At the same time, some states (States E, F and G) have not adopted (as a matter of state law) state regulations or plans. EPA can determine that midstream operations that are regulated under state regulations adopted as a matter of state law pursuant to EG OOOOc in States A, B, and C meet the requirements under §7436(f)(6)(A) and are exempt from the methane fee. To the extent that an operator's assets span multiple states, then the operator should be exempt from the methane fee for emissions associated with any assets in a state that has adopted (as a matter of state law) regulations that are in effect (*i.e*., States A, B, and C above) pursuant to EG OOOOc.

I.K.ii. <u>Who, and when, can someone apply for an EPA determination?</u>

AXPC recommends that the EPA Administrator make a determination as soon as possible – even on a subset of sources – to maintain the purpose of the MERP and to minimize administrative burden.

EPA should establish procedural regulations as soon as possible for how states and operators can petition the EPA for a determination (if EPA has not acted) and timeframes for when EPA will make the determination. **If EPA has not independently made a determination, we recommend that EPA allow any of the following groups to petition EPA individually or jointly for a determination:**

- Owner or operator subject to the MERP;
- State or states where operators subject to the MERP operate; and
- Trade association representing owners or operators subject to the MERP.

We recommend that EPA commit to reviewing and approving/disapproving petitions within three months of receiving them, and to make the determination retroactive to the date of the petition for determination.

To the extent that EPA takes longer than three months to dispose of a petition, we recommend that any methane fee payments made by operators that would have been exempted if EPA had granted the petition be held in abeyance or placed into a separate fund such that they can be refunded if the determination is made.

I.K.iii. Applicable facility is one in compliance with and subject to NSPS OOOOb or EG OOOOc.

According to 42 U.S.C. § 7436(f)(5), "[c]harges shall not be imposed . . . on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsection (b) and (d) of section 111 . . ."

The intent of this language is to ensure that facilities are generally in compliance with and subject to EPA's methane regulations. Congress did not intend that the MERP serve as "double punishment" in the case of any potential for, or allegation of, any compliance violation.

If EPA believes that this language requires an applicable facility to be in compliance at all times or the MERP would go back into place, it is unclear for how long the methane fee would be reinstated – *e.g.,* for only the applicable reporting year? – and would require the applicable facility to be collecting information even if the fee does not apply which would undermine the purpose of the regulatory exemption. This additional unnecessary burden on the regulated entity and the administrative burden on the EPA, without providing any additional methane reduction, is a strong policy reason for why small compliance issues should not be treated as an initial triggering or a retriggering of the methane fee.

EPA has broad enforcement discretion on how to treat compliance. **EPA can and should interpret not being "in compliance with" requirements as long-term, knowing, and malicious states of noncompliance with EPA's methane regulations.**

I.K.iv. Methane emissions standards and plans have been approved and are in effect.

42 U.S.C. § 7436(f)(6)(A)(i) states that "methane emissions standards and plans pursuant to Section 111(b) and (d) have been approved and are in effect in all states with respect to the applicable facilities."

I.K.iv.a. New Sources

With respect to sources that are regulated under Clean Air Act (CAA) § 111(b) (*i.e.*, new sources), states do not submit plans. Under §111(b), EPA itself promulgates new-source standards, without the intermediate steps of state-plan submission and approval as under §111(d) for existing sources. Thus, the date of EPA's final NSPS OOOOb requirements should be deemed the approval date for sources regulated under NSPS OOOOb and the effective date should be sixty days following EPA's final NSPS OOOOb. To the extent that EPA does not consider the date of publication in the federal register of the final NSPS OOOOb as "approval," then EPA must conclude that the term "have been approved" applies only to state plans. In either event, this condition for eligibility for MERP exemption for new sources is satisfied once EPA's final NSPS OOOOb has been published and takes effect.

Further, this provision can only be reasonably interpreted such that the determination of whether *new-source* standards "are in effect" should be made separately from any determination of whether *existing-source* standards "have been approved and are in effect." It would be unreasonable to tie new-source eligibility for the exemption to the status of existing-source regulation. Congress's goal in the MERP is to ensure emissions reductions in keeping with the text and structure of §111, and the MERP provision should be read in harmony with that §111 (in keeping with the fundamental axiom that all statutory provisions are to be read in harmony with one another to the greatest extent possible).

Assuming that the final rule is "equivalent" to the November proposal within the meaning of the Inflation Reduction Act (IRA), AXPC recommends that the EPA Administrator make the determination of this equivalency with respect to new sources at the same time of the final rule or before reporting and recordkeeping requirements go into effect, whichever is earlier.

I.K.iv.b. Existing Sources

For existing sources, under CAA § 111(d), states develop and submit to EPA plans establishing standards of performance. Here, AXPC anticipates all 50 states will need to submit plans, because all states have gathering and boosting stations within them, even if there are no upstream production facilities in a given state.

Due to the difference in resources available across different state agencies, and to the unique nature and distribution of each state's fleet of existing sources, it is highly likely that states will submit their state plans at different times and that these state plans will feature different levels of detail, which will require varying and unpredictable devotion of EPA resources to plan review.

Furthermore, it would not be reasonable to interpret the term "in all states" to require that *all* states have approved state plans (or promulgated federal plans, as discussed below) in order for the facilities in any *one* state to be eligible for the exemption. If there are delays or other obstacles to approving state plans or promulgating federal plans in one or a handful of states, Congress showed no sign that it wanted to penalize facilities in other states where a state or federal plan is in effect. Instead, Congress by using the phrase "in all states *with respect to the applicable facilities*" (emphasis added) recognized that facilities may reside in multiple states. The best, perhaps the only permissible, reading of this provision is that, for an existing-source facility to qualify for the exemption, a state (or federal) plan must be in effect in all states within whose territory the facility extends.

Therefore, **EPA should provide state-by-state determinations for existing sources as soon as possible.** This will encourage states to move faster in development of their state plans and thus reduce emissions faster.

It is possible that states could submit plans required pursuant to §111(d) in a phased fashion as long as each plan is submitted prior to the deadline. AXPC believes if the states have adopted plans that implement EG OOOOc in part, then the exemption should apply for those sources covered by the state plans that have been adopted.

Such phasing could allow states to begin implementing the requirements from EG OOOOc faster, which will reduce emissions faster. If MERP exemption eligibility were deferred until a state has adopted *all* provisions of the state plan, that would disincentivize expeditious adoption of provisions with respect to many of those most prominent emissions sources, delaying reductions and resulting in considerable foregone emissions reductions.

Finally, if a state does not submit a "satisfactory" plan, EPA has authority to prescribe a federal plan for existing sources in that state under §111(d)(2). It is at the very least reasonable for EPA to interpret the IRA's language such that a federal plan being "in effect" in the state (or multiple states in the case of facilities extending across state lines, as discussed above) satisfies this prerequisite for the exemption. Conversely, it would be unreasonable to interpret this language such that a federal plan will not satisfy this prerequisite. The purpose of the MERP is to ensure emissions reductions; there is no sign that Congress wished to disregard reductions effected by federal plans for existing sources.

I.L. Equivalency for the MERP

I.L.i. How to calculate equivalency of the final rule versus the November 2021 Notice.

AXPC agrees with EPA that it is not appropriate to quantitatively compare the November 2021 Notice with the Supplemental Proposal, nor would it be appropriate to quantitatively compare the final rule with the November 2021 Notice. The November 2021 Notice did not provide any regulatory text for new subparts OOOOb or OOOOc, and provided proposed requirements that were not technically feasible. EPA has understood that some of the requirements were not possible as they modified them in the Supplemental Proposal. Therefore, the emissions reductions expected within the November 2021 Notice would not have been realized as estimated within the rule.

We also agree with EPA that the Supplemental Proposal is at least as stringent as the November 2021 Notice due to the significant new modifications to the rules, and if industry's comments and recommendations are implemented in full by EPA, we believe that the final rule would still be as stringent as the November 2021 Notice.

According to Table 5-5 of EPA's 2022 RIA,[26] fugitive emissions, pneumatic devices, and reciprocating compressors make up a large portion of the emissions reductions. With respect to fugitive emissions, the inclusion of additional ways to do aerial monitoring as well as the potential for continuous monitoring will result in increased emissions reductions from the November 2021 Notice. Also, the November 2021 Notice exempted certain types of sources that are no longer exempted resulting in additional emissions reductions.

For pneumatic devices and reciprocating compressors, the requirements for the Supplemental Proposal achieve significantly greater emissions reductions than the November 2021 Notice.[27]

[26] US EPA, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Nov. 2022) (Document ID No. EPA-HQ-OAR-2021-0317-1566) (hereinafter referred to as the "2022 RIA").

[27] See US EPA, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Table 2-11 (Oct. 2021) (Document ID No. EPA-HQ-OAR-2021-0317-0173).

I.L.ii. State programs are by law equivalent to EPA's regulations.

The November 2021 Notice did not provide much, if any, detail on how states can apply "remaining useful life and other factors" (RULOF) but acknowledges that its application is within the authority of the CAA and the states. Therefore, the use of RULOF is inherent within the stringency of the November 2021 Notice, even if EPA does not quantify or monetize those provisions. Also, the state plan that is submitted to EPA must be deemed to be a "satisfactory plan" consistent with the requirements under CAA § 110. If a state fails to submit a satisfactory plan, EPA has authority to establish a federal plan that would cover the EG OOOOc designated facilities.

Therefore, as long as the emissions guidelines established by EPA in the final rule are at least as stringent as the November 2021 Notice, any approved state plan will inherently achieve equivalent or greater emissions reductions as compared to the November 2021 Notice. Congress enacted the MERP in full awareness of the long-standing text and structure of §111(d), and the MERP does not repeal by implication or in any other way detract from this other statutory provision. The only way to read these two statutory provisions (the MERP and §111(d)) in harmony is for EPA to deem any "satisfactory" state plan that it approves as equivalent to its own new-source regulations under §111(d). To do otherwise would conflict with Congress's earlier choice to establish an existing-source regulation program mediated through a state-planning process.

For any state plans that EPA deems to be inadequate, the federal plan will act to replace the state plan and would serve as an equivalent plan.

II. Substantive Requirement Comments

AXPC provides the following specific comments on substantive requirements of the proposal. In light of the limited time for review, AXPC notes that its failure to provide specific comments should not indicate support and should not reflect that there are not outstanding concerns with substantive requirements. AXPC has prioritized the issues of greatest concern to its members, but understands that its fellow trade associations have also raised significant concerns. AXPC generally supports concerns relayed by its fellow trade associations where they do not specifically conflict with AXPC's comments, particularly those comments submitted by the American Petroleum Institute.

II.A. Oil Well Associated Gas

AXPC supports the reduction of routine flaring of associated gas and appreciates EPA's recognition that associated gas flaring is appropriate where the sale, beneficial use, or reinjection of associated gas is not technically feasible or safe. However, AXPC does not agree that EPA's proposal appropriately accounts for economic considerations and believes that EPA's proposal stretches the bound of technical feasibility too far.

II.A.i. Definitions

The Supplemental Proposal would apply standards to oil wells with associated gas at well affected facilities (or well designated facilities under EG OOOOc) but does not define the terms "oil well" or "associated gas."[28] Without definition, the applicability of these standards is unclear. To avoid

[28] *See* Proposed 40 C.F.R. §§ 60.5377b, .5391c.

confusion in implementation and enforcement, AXPC urges EPA to define these terms as proposed below.

II.A.i.a. <u>"Oil Well" Definition</u>

The term "oil well" is ambiguous and needs definition to avoid unintended applicability. While EPA proposes to define "well" as a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected,[29] it does not propose to define oil well or gas well separately. Absent a clear and objective definition, the "oil well" associated gas standards might be interpreted to apply to gas wells, which as noted in the preamble of the Supplemental Proposal, is not EPA's intent.[30] Oil and natural gas wells produce natural gas and hydrocarbon liquids, and these liquids are generally characterized as crude oil or condensate depending on the jurisdiction or context. Regulatory authorities often look to the produced gas to hydrocarbon liquids ratio to define whether a well is an oil well or a gas well but do so inconsistently. The Bureau of Land Management (BLM), in its *Waste Prevention, Production Subject to Royalties and Resource Conservation* proposed rule ("Waste Prevention Proposed Rule"),[31] defined "gas well" as,

> a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio greater than 6,000 standard cubic feet (scf) of gas per barrel of oil is a gas well.[32]

Like EPA's proposals in NSPS OOOOb and EG OOOOc, BLM's Waste Prevention Proposed Rule targets oil well associated gas flaring. **AXPC proposes that EPA define oil well in the converse of how BLM proposes to define gas well, such that oil well is defined as:**

> **a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, is less than or equal to the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio less than or equal to 6,000 standard cubic feet (scf) of gas per barrel of oil is an oil well.**

AXPC believes this definition is objective and unambiguous and urges EPA to adopt this definition into the respective definitions of NSPS OOOOb and EG OOOOc. This definition is also consistent with how the US Energy Information Administration (EIA) defines oil well and gas well.[33] Further, using this definition will provide consistency across overlapping federal regulatory requirements and avoid conflicting regulatory requirements.

II.A.i.b. <u>"Associated Gas" Definition</u>

Without definition, the term "associated gas" could take on various meanings. The most literal interpretation could mean *any* gas associated with oil well production, which might include emissions from other NSPS OOOOb or EG OOOOc affected/designated facility types that EPA regulates in other

[29] *Id.* §§ 60.5430b, .5430c.
[30] 87 Fed. Reg. at 74,778.
[31] 87 Fed. Reg. 73,588, 73,616 (Nov. 30, 2022).
[32] *Id.* at 73,616.
[33] *See* US Energy Information Administration, *The Distribution of US Oil and Natural Gas Wells by Production Rate*, 3 (Dec. 2022) (using 6,000 scf of gas per barrel of oil to distinguish oil wells from gas wells).

sections of its proposal – *e.g.*, collection of fugitive emissions components or storage vessels. EPA's intent in the November 2021 proposed rule was to prioritize gas sales where a sales line is available, which suggests EPA's intended target for these provisions is gas that could be routed to an available pipeline – *i.e.*, produced gas generated in the first stage of separation. To avoid ambiguity and potentially overlapping requirements under the proposed rule, AXPC suggests that EPA define "associated gas" consistent with this intent.

The ability for an operator to inject gas into a pipeline is a function of the pipeline operating pressure and the pressure of the gas source immediately upstream of the pipeline connection. If the gas source's pressure exceeds the pipeline pressure, the gas can enter the pipeline (assuming the gas composition meets required specifications for the pipeline), but if the source pressure is equal to or less than the pipeline pressure, the gas cannot flow into the pipeline. At most production facilities, a mixed stream of liquids and gas leaves the wellhead and goes to a separation vessel where gas is separated from the liquids and routed offsite. In some cases, operators use a portion of this gas for on-site operations. The gas evolved from liquids in this first stage of separation has the highest pressure, and operators inject this gas into a pipeline where available and feasible. Further, the volume of gas evolved in the first stage is typically of much greater volume than gas evolved in subsequent stages of separation, and the gas evolved in subsequent stages of separation is generally not of sufficient pressure for injection into a pipeline. For the lower-pressure gas evolved in subsequent separation, injection into a pipeline often requires compression, which is a significant cost and often requires use of a combustion engine. Given the lower volumes generated in subsequent separation stages, compression is often uneconomical and accompanied by potential environmental disbenefit where gas compression emissions outweigh the emissions reductions achieved by transporting the gas offsite by pipeline as opposed to controlling it onsite. The environmental disbenefits become more pronounced as a well's production levels decrease over time. This is because the compressor's operation and associated emissions will remain relatively static over time, but the total gas evolved will decrease over time, meaning a similar amount of compression emissions will occur to achieve increasingly fewer emissions reductions over the life of the well.

Given EPA's intent to prioritize gas sales and, with respect to the gas evolved in later stages of production, the physical constraints and potential environmental disbenefits, **AXPC proposes that EPA define "associated gas" as**

> **the natural gas evolved from hydrocarbon liquids during the initial stage of separation following production from the wellhead. Associated gas does not include natural gas associated with well completion or downhole well maintenance activities.**

II.A.ii. No justification is necessary for the temporary control of associated gas.

For wells where the operator has designed and configured the separator to recover and sell or beneficially use associated gas, AXPC proposes removal of the requirement to provide an infeasibility or safety justification for controlling associated gas when the primary means of disposition is temporarily unavailable. For these configurations, AXPC supports controlling the gas by using a permanent control device that meets the applicable control device requirements during periods when the primary means of disposition is unavailable. In the scenario where control is temporarily necessary, the operator would route the gas to the control device as soon as practicable. This is consistent with EPA's acknowledgment in the preamble that the primary means of disposal may become temporarily unavailable for reasons outside the operator's control and that EPA's expectation is that the operator installs a permanent control device for these periods of temporary control.[34] Requiring a certified justification in this scenario is overly burdensome with no corresponding environmental benefit.

AXPC proposes that EPA remove the requirement in §§60.5377b(b)(1) and 60.5377c(b)(1) to provide a certified justification for controlling associated gas where the operator complies with (a)(1), (2), (3), or (4) during normal operations and temporarily controls associated gas when the primary method of disposition is unavailable. *See* Section II.A.v of these Comments for AXPC's proposed redline incorporating this concept.

II.A.iii. <u>EPA should not require consideration of predetermined beneficial uses for oil well associated gas, and, if EPA retains such a list, any included beneficial use must be commercially viable.</u>

EPA proposes that operators must certify that use of "recovered gas for another useful purpose that a purchased fuel or raw material would serve" is not feasible "due to technical or safety reasons" before the operator may control associated gas onsite. EPA proposes the feasibility analysis must include consideration of using gas for "methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas." AXPC fully supports the beneficial use of natural gas where reasonably feasible and cost-effective and further supports development of additional technologies that would provide a broader range of potential beneficial uses. EPA's inclusion of a predetermined list of uses suggests EPA has determined each of these beneficial uses is technically feasible, commercially available, and appropriately included as part of associated gas BSER. EPA, however, has provided no support for this apparent determination.

Accordingly, **AXPC requests that EPA remove this list of beneficial uses**.

Further, to the extent EPA maintains such a list of beneficial uses, AXPC requests that EPA remove any unproven "emerging technologies." Clean Air Act § 110(j) provides the appropriate pathway for sources to evaluate emerging technologies to meet new source performance standards. Requiring evaluation of unproven emerging technologies sidesteps both the BSER demonstration and the §110(j) process in violation of the Clean Air Act.

In the preamble, EPA solicits comment on potential emerging technologies that could expand the universe of beneficial gas use and provides two examples of what it considers to be emerging technologies – methane pyrolysis and condensing gas and transporting it to other sites for use. EPA cites two comments in support of these emerging technologies. One commenter – a company in development of a methane pyrolysis solution – suggests that EPA should adopt methane pyrolysis as an express useful purpose in the rule, but precedes this suggestion with an admission that its methane pyrolysis solution is neither scaled nor readily available for implementation. The commenter then requests that EPA grant a performance standard waiver for its unproven technology.[35] In fact, the commenter indicates its technology is in early stages of testing and has not been tested in a field setting. AXPC fully supports development of methane pyrolysis as a commercially scaled and available technology to reduce gas flaring; however, it is not commercially available today, and EPA should not require every beneficial use analysis to evaluate such an unproven solution. While one-off methane pyrolysis use may be technically *possible,* methane pyrolysis is not a commercially feasible solution on the scale of implementation that may be required under this proposed rule. EPA's express inclusion of it

[34] 87 Fed. Reg. at 74,780.
[35] *See* Document ID No. EPA-HQ-OAR-2021-0317-0594, 5.

as a beneficial use in the final rule suggests methane pyrolysis is feasible (including on a commercial scale), while it is not, and would provide a windfall to this commenter.

The commenter supporting methane pyrolysis suggests a couple of pathways for approving the use of its methane pyrolysis technology – a CAA § 110(j) waiver and a commercial demonstration permit. We encourage the commenter to evaluate these paths; however, neither is a pathway to including its product as a required consideration in a NSPS or Emissions Guideline control evaluation.

Regarding condensing gas and transporting it offsite for use, EPA cites one comment that makes no mention of condensing gas. AXPC can only guess that EPA means to reference the one sentence in the comment that suggests gas can be compressed and trucked to a processing plant or other location with no support for whether this solution is feasible or safe.

While AXPC believes that EPA should not expressly include any enumerated beneficial use and leave operators to determine the universe of beneficial uses reasonably available, **if EPA includes any list of beneficial uses, AXPC requests that EPA remove technologies that are not proven and/or commercially available, including methane pyrolysis and condensing gas and transporting it offsite.** Including these technologies in a list of feasible beneficial uses that operators must consider in every associated gas control analysis sidesteps the requisite BSER analysis in violation of the Clean Air Act.

With respect to converting gas to liquid, current gas liquefication technology is capable of converting only the heavier-end gaseous hydrocarbons to liquid, requiring the control of methane and potentially other lighter-end hydrocarbons that remain in the gaseous phase following processing. Thus, gas to liquid conversion will not provide for complete use of the gas stream. Additionally, the equipment necessary to process gas to liquids is expensive to deploy and maintain and of limited commercial availability. While gas to liquid conversion may be viable in some instances, it is not a universally viable solution. **Accordingly, EPA should remove gas to liquids conversion from the list of beneficial uses that operators must consider. AXPC includes a proposed redline in Section II.A.v below.**

Finally, EPA includes the production of liquified natural gas in its list of beneficial uses. While operators have removed natural gas liquids from field gas using equipment deployed to or near well sites, this equipment has proven to be an unreliable permanent solution for several reasons, including vendor availability and safety. AXPC supports the expanded utilization of equipment that can extract natural gas liquids from field gas in the upstream sector; however, AXPC believes it unnecessary to expressly include this as a consideration in a technical infeasibility analysis. **Accordingly, AXPC requests that EPA remove the production of liquified natural gas from the list of required beneficial use considerations.** Further, the proposed definition of "natural gas processing plant" serves to disincentivize the production of liquified natural gas, as discussed below.

II.A.iv. <u>EPA must revise the definition of "natural gas processing plant" to incentivize development of a broader range of potential beneficial uses for associated gas.</u>

EPA defines a "natural gas processing plant" as "any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant."[36] NSPS OOOOb and EG OOOOc treat gas plants differently than other oil and natural gas facilities – *e.g.*, gas plants have significantly more stringent leak

[36] Proposed §§ 60.5430b, .5430c.

detection and repair requirements – and has done so over time under the premise that gas plants are manned continuously. However, under the proposed definition, equipment used to put associated gas to beneficial use (as required by EPA's proposed oil well associated gas requirements) would be a natural gas processing plant if the equipment extracts natural gas liquids from field gas. Indeed, one of EPA's enumerated beneficial uses is the production of liquified natural gas, which requires the extraction of natural gas liquids from field gas. In some regions, operators utilize small natural gas liquids extraction skids, and EPA has recognized this fact in its exclusion of certain types of equipment from the natural gas processing plant definition. However, to further incentivize the beneficial use of associated gas through use of technologies or processes not explicitly excluded from the definition – *e.g.*, a mobile refrigeration skid – EPA should exclude equipment with a design processing capacity of less than 10 MMscf/day. **AXPC proposes that EPA define natural gas processing plant as,**

> **any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The following are not a natural gas processing plant: a Joule-Thompson valve, a dew point depression valve, ~~or~~ an isolated or standalone Joule-Thompson skid, or any combination of equipment having a design natural gas processing capacity of 10 MMscf per day or less.**

II.A.v. The feasibility demonstration must also consider commercial availability and economic viability.

As noted above, AXPC proposes eliminating the requirement to justify use of control in many circumstances. However, where a justification continues to be required, AXPC provides the following additional comments regarding economic viability. These comments are in addition to the comments in Section I.B of these Comments which addresses these considerations more generally. AXPC fully supports the concept of prioritizing the sale or beneficial use of associated gas as opposed to control where markets exist and disposition into those markets is economically viable. Building upon the arguments above, EPA must allow operators to control associated gas where no viable gas market exists, taking into account the commercial availability of a gas sales pipeline or other potential market and site economics to deliver gas to market. This is consistent with the World Bank's "Zero Routine Flaring by 2030" initiative, in which some AXPC members are participants. This global initiative encourages operators "to implement **economically viable** solutions to eliminate [routine] flaring as soon as possible."[37] While a use may be technically feasible, it may not be commercially viable, as discussed more above with respect to a use's commercial availability.

In addition to commercial availability/viability, a potential gas disposition method must be economically viable. For example, a remote well site operator could identify a pipeline with sufficient capacity, but the closest pipeline with sufficient takeaway capacity may be 100 miles away. And the cost to build, maintain, and operate the connecting pipeline may well exceed the total value of the gas that could be sold. Further, the additional infrastructure development is not without environmental impacts – *e.g.*, the impacts associated with the construction and installation of the pipeline. While it would be technically feasible to build this connecting pipeline, it is not a an economically viable solution – *i.e.*, a

[37] The World Bank, *Global Initiative to Reduce Gas Flaring: "Zero Routine Flaring by 2030", available at* https://thedocs.worldbank.org/en/doc/a903b5e6456991faf3b5e079bba0391a-0400072021/related/ZRF-Initiative-text-list-map-103.pdf (emphasis added).

cost-effective solution, as noted by EPA.[38] To ignore economic viability would result in a rule that does not provide "achievable, cost-effective measures to significantly reduce methane and VOC emissions, consistent with the requirements of section 111 of the CAA."[39]

Not only is it good policy to consider a control measure's economic viability, Clean Air Act § 111 requires it, as evidenced by its plain language and EPA's many references to the Proposal's cost-effectiveness. As noted in the regulatory impact analysis, which explicitly excludes any substantive analysis of the cost-effectiveness of EPA's proposed oil well associated gas requirements, control of associated gas is appropriate where an operator does "not produce a large enough quantity of associated gas to offset the capital necessary to install" the infrastructure necessary to sell gas or use it in another beneficial way.[40] Inherent in this suggestion is the notion that economic considerations play a role in determining the feasibility of selling or using gas for a beneficial purpose.

AXPC proposes that EPA revise the proposed §60.5377b(b), and the corresponding EG OOOOc provision, to include economic and commercial considerations as below. Note, the revisions below include revisions proposed by AXPC relating to the beneficial use of associated gas:

> **(b) If you demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section due to technical, economic, lack of commercial availability, or safety reasons in accordance with paragraphs (b)(1) through (3) of this section, you must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that meets the requirements of §60.5411b(a) and (c) and the control device must meet the conditions specified in §60.5412b(a), (b) and (c).**
>
> > **(1) In order to demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section, you must provide a detailed analysis documenting and certifying the technical, economic, lack of commercial availability, or safety reasons for this infeasibility. The demonstration must address the technical, economic, lack of commercial availability, or safety infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section. ~~With regard to compliance with paragraph (a)(3) of this section, another useful purpose that a purchased fuel or raw material would serve includes, but is not limited to, methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas.~~ Documentation of these demonstrations must be maintained in accordance with §60.5420b(c)(3)(ii). If the primary means of disposition of oil well associated gas is one of the options identified in (a)(1), (2), (3), and/or (4) of this section, you do not need to complete, certify, or document the detailed analysis in this section to utilize temporarily the option in §60.5377b(b).**

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[38] *See* 2022 RIA at 153 (noting "[i]installation of a sales pipeline or other infrastructure necessary to use associated gas in a beneficial way is very costly, especially where well sites are located at great distances from other necessary infrastructure, such as natural gas processing plants …").

[39] *See* 87 Fed. Reg. at 74,705.

[40] 2022 RIA at 26, 153 (note, EPA's quoted comments are with respect to small businesses; however, the well site economics for the sale or beneficial use of associated gas are the same for every operator).

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer of other qualified individual shall state: "I certify that the assessment of technical, economic, lack of commercial availability, and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of §60.5377b(b)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

II.A.vi. EPA should allow operators to control associated gas from wildcat or delineation oil wells without justification of technical infeasibility or safety reasons.

AXPC supports American Petroleum Institute's (API) suggested redline and supporting comments that would allow operators to utilize a temporary or portable combustion device similar to those used to control emissions from well completions to reduce VOC and methane emissions from wildcat or delineation oil well associated gas without justifying that sale, beneficial use, or reinjection is technically infeasible or unsafe.[41] As noted by API, these wells typically cease production within 180 days and are typically remotely located significant distances from natural gas pipelines. **AXPC suggests including the following redline in §§60.5377b and 60.5391c:**

For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

II.A.vii. If a justification is required, EPA should allow operators to develop a gas capture plan for similarly situated oil wells with associated gas.

As noted above, AXPC proposes eliminating the requirement to justify use of control in many circumstances. However, where a justification continues to be required, AXPC provides the following additional comments regarding such justifications. EPA proposes that operators prioritize the sale, use,[42] or injection[43] of crude oil well associated gas over use of a control device to reduce emissions, and where an operator must control associated gas emissions because it is technically infeasible or unsafe to sell, use, or inject associated gas, it must justify and certify why. This requirement applies to "each oil well with associated gas at a well affected [or "designated" under EG OOOOc] facility,"[44] meaning the certification requirement would apply on a well-by-well basis. If the exemption from justification proposed by AXPC is not adopted, this may require hundreds or thousands of certifications that would

[41] *See* API Supplemental Proposal Comments § 4.5.
[42] "Use," under EPA's Supplemental Proposal, means the recovery of associated gas from the separator and use of the recovered gas (i) as on onsite fuel source or (ii) for another useful purpose that a purchased fuel or raw material would serve.
[43] "Injection," under EPA's Supplemental Proposal, means the recovery of associated gas from the separator and reinjection of the recovered gas into the well or into another well for enhanced oil recovery.
[44] *See* Proposed 40 C.F.R. §§ 60.5377b(a), .5391c(a).

be unnecessarily onerous where similarly situated oil wells must control associated gas emissions to comply with the oil well associated gas provisions, even where control is limited to temporary situations.

Because regional circumstances often dictate associated gas disposition, an operator may comply with the associated gas standards in the same manner for all or many wells in a region, and where the primary means of compliance is unavailable, the operator is likely to use the same alternative method(s) of compliance for all similarly situated wells. For example, where gas pipeline takeaway is readily available in a region, the operator will dispose of natural gas produced from all wells in the region into the pipeline and route gas to control when the pipeline is temporarily unavailable. For these similarly situated wells, it would be most efficient for the operator to use one document that covers all wells to identify the primary compliance approach – *e.g.*, pipeline injection – and the technical infeasibility or safety justification for controlling gas when the primary compliance approach is unavailable.

AXPC proposes that, as an alternative to a well-by-well certification requirement, operators may develop a system-wide gas capture plan that would cover all similarly situated oil wells – *e.g.*, oil wells that share a common gas gathering system or other appropriately representative grouping. Under this plan, operators would identify the primary means of complying with §§60.5377b(a) or 60.5391c(a), as applicable, and where the operator must control associated gas because the primary means of associated gas disposition is technically infeasible or unsafe, the operator would provide a commonly applicable justification. For example, as EPA identifies in the preamble, interruptions to the gas gathering system may affect an operator's ability to sell gas. [45] In these instances where operators dispose of associated gas via pipeline, operators are unlikely to have the infrastructure available to use the gas for another purpose or to reinject the gas, leaving control as the only other feasible option. In response to the commenters that identified this potential issue, EPA proposes that operators "provide a technical or safety demonstration in their annual report and install and operate a control device that achieves the required reduction during these temporary periods."[46] The same logic would apply for operators that use gas for a beneficial purpose or re-inject gas. Like with gas sent to pipeline, a beneficial use or re-injection may become unavailable without notice, and the operator must instead control the gas.

Applying the example in the second paragraph above to the gas capture plan approach, the operator would identify pipeline injection as the primary compliance method for all wells covered by the gas capture plan, and when pipeline disposition is technically infeasible – *e.g.*, due to capacity constraints or pipeline downtime, the operator will comply with §60.5377b(b) by controlling the associated gas with a control device meeting all applicable NSPS OOOOb requirements. The operator would provide the justification of technical infeasibility that is commonly applicable to all wells covered by the gas capture plan, and no well-by-well justification would be required.

Under this gas capture plan approach, operators would maintain records of compliance with the gas capture plan and report compliance in a similar manner as currently proposed. Using the example above, if the operator vents gas rather than controls it, the operator would maintain records of this event and report its occurrence in the annual report. Similarly, operators that control associated gas during a reporting period would provide a copy of the gas capture plan's justification applicable to the well(s) that required associated gas control during the reporting period.

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[45] 87 Fed. Reg. at 74,780.

[46] *Id.*

Just as with the proposed requirement to consider changes that would impact an operator's ability to comply with the requirements to sell, use, or re-inject associated gas, AXPC proposes that operators that routinely or periodically control associated gas under a gas capture plan would consider and report on any changes in the region that impact the operator's ability to comply with the requirement to sell, use, or re-inject associated gas.

This approach provides a more efficient means of recordkeeping and reporting while maintaining the same degree of transparency as EPA's proposed standards. Though AXPC does not articulate concerns here, AXPC has concerns similar to API's with regard to the "certification" itself and supports API's comments on certification (*see* API Supplemental Proposal Comments § 12.9).

To summarize, **AXPC requests that EPA add language to the oil well associated gas provisions that would allow operators to develop a gas capture plan for similarly situated oil wells with associated gas. Operators must develop and maintain records of the gas capture plan, which must identify the primary method(s) of gas disposition, and where control of associated gas is necessary on a permanent or temporary basis, the operator must justify the technical infeasibility and/or safety justification for controlling the gas, with such justification to apply to all wells covered by the gas capture plan. Operators using a gas capture plan would maintain records and report under a framework similar to the Supplemental Proposal's recordkeeping and reporting requirements**.

II.B. Super-Emitter Response Program

AXPC provides the following specific comments on EPA's super-emitter program. As noted at the outset, AXPC's failure to provide specific comments should not indicate support or lack of concern with specific provisions. AXPC supports concerns relayed by its fellow trade associations, particularly the American Petroleum Institute. EPA has proposed extensive new requirements relating to an affected facility that EPA describes as super-emitter emissions events. AXPC has significant concerns with EPA's proposed super-emitter emissions event affected facility and requirements. As an initial matter, AXPC does not believe that EPA has the authority to adopt super-emitter requirements in the manner that EPA proposes. Specifically, AXPC disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a §111 emissions standard. Rather, at most, EPA has the ability to consider identification of super-emitter events as "monitoring" of an affected facility. As such, super-emitters may only occur from affected facilities. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not an affected facility. In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this intent in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111. **Thus, AXPC does not believe that EPA has the authority to adopt the super-emitter emissions event as an affected facility type and proposes that EPA remove these provisions in the final rule.**

Setting aside the lack of legal authority, EPA's proposed rule language lacks clarity regarding whether super-emitter events can only be identified at affected facilities covered by NSPS OOOOb (or upon adoption by the states, from designated facilities covered by EG OOOOc). In its preamble, EPA makes numerous statements that indicate it intends that super-emitter emissions events can come only from NSPS OOOOb/c sources, including:

- EPA's conclusion that a super-emitter emissions event that requires mitigation is one "either due to a failure to comply with one of the standards in this rule or due to an upset or malfunction at a source covered by this rule."[47]
- Owners and operators would have the opportunity to rebut information provided by the third party, including that "the emissions event did not occur at a regulated facility."[48]
- "Where compliance is achieved with the applicable standards, the EPA does not expect unintentional releases at these very high levels to occur in normal operation."[49]
- "Super-emitter emissions events could also be from intentional venting as part of normal operations or maintenance. The proposed super-emitter response program discussed in this section is not intended to address these events."[50]
- "[T]he super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule."[51]

Despite the language from the preambles, EPA's draft proposed regulations do not specifically state that the super-emitter emission events only occur at NSPS OOOOb affected facilities (or designated facilities). Rather, EPA simply defines a super-emitter emissions event to be any source of emissions over the threshold "located at an individual well site, centralized production facility, or compressor station." Nowhere does EPA make clear that it must be located at one of those facility types that is subject to NSPS OOOOb and also associated with/emitted from an affected facility – an intent the preamble makes clear.[52] However, if EPA does have the authority to adopt super-emitter emission events regulations in a performance standard, such requirements would need to be relevant to and only apply to NSPS OOOOb affected facilities. Therefore, if EPA retains the super-emitter emissions event affected facility, it must revise the definition of a super-emitter emissions event to refer to those emissions above the threshold and associated with an affected facility subject to NSPS OOOOb. Thus, if a third party provides notification of an event over 100 kg/hour of methane, then only those events associated with an NSPS OOOOb affected facility (*e.g.*, if above the thresholds: an unlit flare or combustion device associated with an NSPS OOOOb affected tank battery facility, a malfunctioning natural gas pneumatic controller, *etc.*) could potentially constitute a super-emitter emissions event and require an operator's corrective action or recordkeeping under NSPS OOOOb. Revisions to reflect this intent would need to be made throughout the provisions.

[47] *Id.* at 74,747 (emphasis added).
[48] *Id.* at 74,750 (emphasis added).
[49] *Id.* at 74,749.
[50] *Id.* at 74,749 n.101.
[51] *Id.* at 74,753.
[52] The position that these apply only to NSPS OOOOb sources applies equally to these requirements applying only to EG OOOOc facilities (and then only after the relevant state adopts and begins implementing EG OOOOc). As noted above, for ease of drafting, AXPC refers only to NSPS OOOOb throughout these comments.

In addition to the above overarching scope and applicability issues, AXPC sets forth below additional concerns related to a variety of considerations associated with the super-emitter emissions event affected facility below.

II.B.i. Source Definition

EPA's rule defines a super-emitter emissions event as "any source of emissions" located at an individual well site, centralized production facility, or compressor station, with emissions detected above a certain rate. The use of the term "source" should be clarified and revised consistent with the above discussion. Often under the Clean Air Act, the term "source" refers to the entirety of the stationary source. However, the use of the term source or emissions source throughout the super-emitter provisions makes clear that EPA intends for the term source to mean specific equipment located at one of the specific types of stationary sources. In particular, it is clear EPA intended to apply the super-emitter emissions event program to affected facilities as defined in NSPS OOOOb. For example, EPA requires operators to report the "description of the emissions source, the applicable standard to which the emissions source is subject …" Thus, EPA makes clear here (as well as through use of the term source throughout these provisions) that source refers to the particular affected facility. Thus, EPA must clarify that "source," as used in this section, refers to emissions above the threshold at any individual (*e.g*., storage vessel, pneumatic controller, *etc.*) affected facility. This clarification is important, because if there is no individual piece of equipment or activity emitting over 100 kg/hour, then it should not be considered a super-emitter event – even if the methane emissions rate from the entire source is greater than 100 kg/hr. Further, this clarification is important, because (as proposed below) operators should only be required to conduct an investigative analysis on any NSPS OOOOb affected facilities emitting above the 100 kg/hr threshold.

II.B.ii. Qualifications and Technology

EPA's requirements regarding super-emitter events are inconsistent with other aspects of the New Source Performance Standards (NSPS) and inappropriately treat owners and operators differently from third parties such as environmental organizations. EPA's proposed regulations state that "[i]f in the Administrator's judgment, a third-party (*i.e.*, someone other than the owner or operator of the site with a detected super-emitter emissions event, the Administrator, or the delegated authority) demonstrates technical expertise in any of the remote detection technologies and/or methods specified . . ., the Administrator will approve that third-party."[53] EPA does not, as part of the super-emitter affected facility requirements, require any demonstration regarding the specific technology to be used by the third party – only that the third party has expertise in use of the technology. This is inconsistent with EPA's own statements in the preamble that it seeks to ensure that third parties are using "reliable and demonstrated remote sensing technology."[54] EPA's vague listing of the types of remote sensing technologies (*e.g.*, satellite, continuous monitoring, aerial, *etc*.) does nothing to ensure that the technology being used is in fact reliable or demonstrated. **Specifically, the EPA must ensure each remote sensing technology is proven reliable through a science-based validation process such as peer review and/or third-party field and lab studies that demonstrate the technology's capabilities and limitations and provide end users with an understanding of the technology's quantification precision – *i.e.*, how far from the reported value the true value might be or error bars). Further, AXPC believes any technology used to identify a super-emitter event must be capable of quantifying the methane**

[53] Proposed 40 C.F.R. § 60.5371b(a) (emphasis added).
[54] 87 Fed. Reg. at 74,747 (emphasis added).

emissions rate without reliance on an assumed gas composition. These requirements will help reduce the occurrence of false positives that trigger unnecessary and unwarranted operator response.

As noted above, requiring the third party to have expertise in the technology assures nothing about the technology being used. Having expertise in the use of an unreliable and inaccurate technology could equally result in erroneous results just as lacking expertise in the use of a reliable and accurate technology. And, while EPA discusses sampling protocols used in connection with the technology, EPA does not require the sampling protocols meet any specified standard or otherwise be approved. Further, it is not even clear from the regulatory language whether EPA is proposing to require the full and complete sampling protocols be provided to the operator or whether only a description of the sampling protocols be provided. Regardless of how EPA proceeds in the final rule, any and all sampling protocols must be provided to the operator and should contain standard quality assurance and control provisions. However, it is critically important that EPA requires the third party to demonstrate more than "expertise" in one of the three categories of remote technologies. Instead, the third party must demonstrate the reliability of the remote sensing technology they choose to use and their expertise with the remote sensing technology. In fact, EPA's discussion around revoking a third party's authorization suggests that EPA will be approving the technology (stating that "EPA would not allow use of this type of mechanism to dispute the accuracy of technologies that <u>have been approved by the EPA</u>.")[55] However, as written, EPA does not require approval of the technology. This must be corrected. Specifically, EPA should require the same level of rigor that EPA determines is required for alternative fugitive emissions monitoring including evaluation of error bars, and false positive detection rates.

Importantly, EPA has made clear that it does not believe that all technologies will be appropriate for or sufficient to replace the fugitive emissions monitoring otherwise required. Thus, it is completely illogical and arbitrary that EPA would allow any and all technologies (without limitation) to be used by a third party simply because the third party has expertise with respect to the technology. This not only could allow methodologies that are in the pilot phase, but also allow others that have not been proven to be reliable or accurate. EPA should not allow one entity to use technology to demonstrate a potential violation (or at a minimum, a circumstance that requires investigation and potentially corrective action) and yet not allow the owner or operator to use that same technology to replace existing monitoring requirements. The problem with this inconsistency is compounded by the fact that owners and operators are required to take corrective action in response to the notifications by the third-party, regardless of the accuracy, viability or legitimacy of the technology used. And while, AXPC has concerns with respect to certain of the alternative AIMM requirements, EPA should not allow for a third party to identify super-emitter events without making the same demonstration that EPA finalizes for alternative AIMM in the final rule. To do otherwise would be the epitome of arbitrary and capricious rulemaking. In short, EPA should subject technologies used by third parties to the same approval rigors as the technologies used by industry operators and must ensure the reliability as described in bold above.

Finally, EPA must only authorize technologies that provide enough granularity to enable the third party to identify the correct site and the specific equipment or activity from which 100 kg/hr of methane is emitting. If a technology can only identify the total kg/hr of methane from the entirety of the site (*e.g.*, 25-meter x 25-meter area), the third party would not be providing the requisite information necessary for an operator to understand whether a super-emitter emissions event from an affected facility in fact exists.

[55] *Id.* at 74,750 (emphasis added).

II.B.iii. Public Reporting

EPA should not encourage or require public reporting of the notifications provided by third parties. Such notifications (1) may not identify any NSPS OOOOb affected facilities that are emitting above the threshold; (2) may have demonstrable errors; (3) may have been a routine maintenance event; and/or (4) may identify the wrong operator or location. As a consequence, EPA should not consider public reporting until an operator has submitted either its final report or corrective action plan in an effort to prevent the spread of misinformation.

II.B.iv. Confirmation of Emission Rate

In the notification and reporting sections of the super-emitter proposed regulations, EPA states that the third party must provide to the operator, and the operator must report, the "[d]ates of detection of super-emitter emissions event and date(s) of confirmation of emission rate." Thus, this reporting provision makes clear that EPA intends that the notifying entity be required to "confirm" the emission rate that it initially identified. This confirmation must be more than simply reviewing the data and confirming that in fact a suspected super-emitter emissions event exists. EPA should require the third party to confirm (via the same technology utilized initially) that the initially identified emissions rate is ongoing (*e.g.*, conducting another pass over the facility and finding the same results). Such confirmation should be required to occur 24 hours or more after the initial identification. By requiring this confirmation, EPA will reduce the likelihood that third parties provide notice, report to EPA, publicize, and require evaluation by the operator of maintenance events that are already known to the operator or for which the operator has already taken action. Thus, EPA should include language making clear that the notifying entity must identify emissions above the threshold from the same emissions unit as the initial remote monitoring identified.

II.B.v. Potential Abuse by Third Parties

EPA appears to recognize that the super-emitter provisions may result in abuse by a third party. However, EPA's proposed regulations to curb such abuse or targeting are insufficient. AXPC raises the following with respect to this issue.

The criteria for when an operator may report a third party are inconsistent between the regulation and the preamble. The proposed regulatory text states, "[a]ny owner or operator that has received more than three notices of a super-emitter emissions event at the same" site containing demonstrable errors may petition EPA to remove that third party from the list. The regulation continues, "[i]f in, the Administrator's discretion, the notifications contain meaningful, demonstrable errors . . . that third party may be removed" from the approved list. Thus, as written, it appears from the proposed regulation that an operator must demonstrate that the third party provided notifications at the same facility three times and that the notifications contained demonstrable errors. However, in the preamble, EPA makes contradictory statements. Specifically, in one place EPA states that "EPA, in its discretion, may remove that third party from the pre-approved list of third-party notifiers upon demonstration by the owner or operator and/or a finding by the EPA that more than three notifications to that same owner or operator were made in error." And elsewhere, EPA states "EPA has proposed a mechanism for owners and operators to seek a revocation of a notifier's certification from the EPA should they establish that more than one notification contained demonstrable errors." Thus, it is unclear what EPA intends. AXPC contends that EPA should consider revocation upon any demonstration of error – irrespective of the number of notifications. And most certainly, EPA should not require three notifications at the same site before EPA revokes the third party's approved notifier status.

If EPA requires three erroneous notifications at the same site before any potential action could be taken against a third party's status, it could result in thousands of inaccurate and faulty determinations. In light of the number of facilities held by one owner or operator (often hundreds or thousands), a third party could target industry (or even the same operator daily) (at one or more locations) without hitting the same facility for several years. This is particularly true if virtually any and all satellite imagery can be used to detect super-emitter events. For example, a third party could simply have a team of personnel sitting behind their desks reviewing satellite data and producing notifications. And even if they provided one notification per day, an operator with 500 facilities would not see the third notification for several years. Further, if the threshold remains three times at a single facility, antagonistic organizations could readily coordinate to make sure that they alternate attention to a certain area/basin/field and thus prolong the time period for any one third party to hit three notifications. **AXPC proposes that there should be no minimum threshold for the number of unfounded notifications provided by a third party before EPA moves to revoke the notifier's status. Or, at a minimum, it should be the total number of faulty notifications provided across all facilities, regardless of the owner/operator of the facilities.**

Even under EPA's proposed cure to potential abuse or incompetence, an operator has to petition to have a third party removed, and there is no guarantee that EPA would remove the third party and no criteria (objective or otherwise) is established for when EPA would remove that third party from the approval list.

II.B.vi. Economic Impacts

EPA has erroneously concluded that "there should be no additional cost associated with this work practice standard for the super-emitter emissions event affected facility." EPA suggests this because EPA expects that "as part of normal operations, owners and operators should already be correcting equipment malfunctions and/or poor operations as such issues arise; therefore, costs associated with maintaining normal operations should already be accounted for in their operational costs."[56] Such logic is entirely circular and inconsistent with EPA's own stated concerns and findings regarding EPA's claimed super-emitter emissions events. If normal operational practices would catch and resolve all super-emitters, then EPA would not have a justification that a super-emitter program is necessary to finding super-emitters. Thus, EPA clearly intends the program to require additional action beyond what is being taken and identified today. AXPC estimates operators would expend at a minimum 20-30 hours of personnel time to respond to and investigate each super-emitter notification, including time spent chasing intermittent events, identifying known maintenance events, communicating with the notifier, conducting a root cause analysis (investigative analysis as proposed by AXPC), responding to public inquiries for notifications posted online, and potentially pursuit of third party notifier disqualification for false notifications. The costs associated with these efforts will depend on whether an operator utilizes internal or external personnel and other operator-specific considerations – *e.g.*, travel distance. However, under no circumstances can EPA simply assume that there will be no costs.

II.B.vii. Investigative Analysis and Initial Corrective Action

EPA's proposed super-emitter event regulations require several specific evaluations and analyses. AXPC addresses its concerns with several below.

[56] *Id.* at 74,752.

- In response to a super-emitter notification, EPA's proposal would require an operator to determine if a natural gas-driven pneumatic controller or pump is venting to atmosphere continuously and requires repair of any controller or pump found venting to the atmosphere during idle periods, even where the pneumatic controller is not related to the super-emitter event. This provision fails to recognize that in many circumstances, operators may be using continuous bleed pneumatic controllers (*e.g.*, approved use under NSPS OOOOb or at EG OOOOc facilities prior to implementation of EG OOOOc and where approved use provided). Continuous bleed pneumatic controllers – by their very nature – vent (or bleed) to atmosphere during non-actuations. Thus, EPA's requirements regarding repair of pneumatic controllers should be limited to natural gas-driven pneumatic pumps and controllers subject to a NSPS OOOOb or EG OOOOc zero emissions standard.

- Similarly, in response to a super-emitter notification, EPA' s proposed regulation requires an operator, upon finding an open thief hatch or open pressure relief valve, to "conduct[] a new engineering certification to ensure the controlled tank battery is designed and operated to achieve the no identifiable emissions standard." First, the engineering certification required by an operator with respect to storage vessels relates only to design and not to operation. Thus, no engineering certification will (or can) address future operations. Second, this requirement to conduct a new engineering certification is illogical. If a thief hatch or PRV is left open, that is most clearly not a design issue, but rather is related to operations. Thus, a new engineering certification will not in any way address the open thief hatch or pressure relief valve.

- Per the comments above, no investigative analysis should be required if the emissions are not associated with/emitting from an affected facility under NSPS OOOOb.

II.B.viii. Public Safety Concerns

EPA's proposed super-emitter program may encourage members of the public to access oil and natural gas facilities in search of super-emitter events. EPA should clearly and unequivocally discourage public members from accessing these facilities and placing themselves in potential harm's way. As noted in our January 31, 2022 comment letter, our industry is committed to the health and safety of the communities in which we operate, and we support public participation in the development of their communities. It is our commitment to the community health and safety that leads us to reiterate the following concerns:

- **There are potential safety concerns associated with members of the public accessing sites without proper notice, personal protection equipment (PPE), and training.** For example, some sites can contain hydrogen sulfide (H_2S), a gas that could result in series health issues for members of the public without proper protection.

- **Well sites are located on private property. EPA's proposal could encourage members of the public to trespass onto private property and to avoid safety signs and considerations.** This could result in members of the public hurting themselves or damaging equipment that could result in putting workers in danger. There is also the question of who would be liable for the safety of the members of the public who illegally trespass on the property or for any damage that they may cause.

II.C. Alternative leak detection technologies

AXPC provides the following specific comments on alternative leak detection technologies. As noted at the outset, AXPC's failure to provide specific comments should not indicate support or lack of concern with a particular provision. AXPC supports many of the comments related to alternative leak detection technologies made by its fellow trade associations, particularly the American Petroleum Institute.[57] In general, AXPC does not believe that EPA's proposal provides a workable or efficient alternative leak detection program that operators could utilize in any significant way. AXPC and its members strongly support the ability to use alternative leak detection technologies under the rules and contend that many of these technologies are at least as effective as optical gas imaging because they can potentially capture more significant leaks more quickly and the screening technologies can obtain information on a greater percentage of facilities faster than an operator can accomplish with optical gas imaging. And more will come, as operators are working to further develop technological capabilities in this area. Thus, EPA's alternative leak detection program needs to be adopted in a manner that ensures that a range of technologies can be economically used now and that new technologies that become available can also be utilized. However, it must be structured significantly differently from the current alternative technology approval process to facilitate use of such devices.

First, EPA must clarify that when it refers to the commercial availability of alternative leak detection technologies, it means that the underlying hardware components are "commercially available" and that EPA does not mean that operators are bound to purchase certain whole package technologies from third parties that are approved by EPA. As industry practices and leak detection technology evolve, operators will likely be involved in the development of systems to more broadly detect and respond to emissions. EPA must clarify the requirement for "commercially available" in a way that facilitates use of commercially available components in leak detection systems, while providing flexibility for operators to develop and build leak detection systems to fit varying operational scenarios. These could include systems that, while made up of commercially available components, may not be sold commercially as a whole package.

Second, EPA should not only rely on the ability to determine a mass emission rate (kg/hr) when assessing alternative leak detection technologies due to the large discrepancies that can occur with mass conversion. EPA should also allow alternative leak detection technologies to use a background concentration and increase from that background level as a means to provide an action level for leak detection. The conversion of a detected concentration of methane to a mass emission rate (*e.g.*, kg/hr) is an added step in estimation that requires site-specific operational data/information that only the operator can provide. Testing of third-party data indicates that there can be a large discrepancy in the mass conversion. Alternative leak detection technologies can also identify a background concentration of molecules and base its action levels on an increase from that background level. This method of detection can be a reliable method of detecting and responding to leaks in real time and does not have some of the challenges presented by mass conversion based off of operator data and calculations.

II.C.i. <u>AXPC supports a multi-layered approach to alternative detection technologies.</u>

AXPC supports the American Petroleum Institute's (API) proposal under which EPA would allow a multi-layered approach to leak detection that would allow operators to combine multiple detection technologies into a flexible, single monitoring plan or network.[58] Under this framework, EPA would allow the deployment of different technologies at appropriate intervals throughout the year, as defined in a monitoring plan. With this concept, an operator could develop a monitoring plan for each

[57] *See* API Supplemental Proposal Comments § 3.0.
[58] *See id.* § 5.1.1.

basin or site that utilizes a suite of EPA-approved technologies via EPA-approved modeling. Additionally, an operator could substitute one technology for another to conduct an inspection where deployment of the originally planned technology becomes infeasible due to weather or other external factors. This approach would both allow the technology to mature over time and presents a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process. For further discussion and support for this multi-layered approach, AXPC directs EPA to API's comments.

II.C.ii. Follow-Up Inspections

AXPC agrees with the American Petroleum Institute comment that **follow-up surveys and inspections, including optical gas imaging camera inspections, (after use of alternative leak detection methodologies) should not be required in instances where the source of detected emissions can be identified based on the localization performance of the alternative technology, AVO inspection, and/or other operation data known to the company.[59] And where source-specific attribution can be determined by the alternate technology, no ground-based inspection follow-up should be required – only the potential for corrective action if the emissions are not authorized.** Lastly, EPA refers to ground-based surveys. However, **where follow-up is required, EPA's regulations should ensure that operators can utilize drone-mounted, or helicopter mounted optical gas imaging for further investigatory analysis.**

II.D. Pneumatic devices

II.D.i. Pneumatic controllers

AXPC provides the following specific comments on pneumatic controllers. As noted at the outset, AXPC's failure to provide specific comments should not indicate support. AXPC supports concerns relayed by its fellow trade associations, particularly the American Petroleum Institute with respect to pneumatic controllers.

II.D.i.a. EPA should include routing to a control device as an emissions reduction standard for pneumatic controllers.

EPA's proposal does not allow operators to route pneumatic controller vent gas to a control device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[60] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. **AXPC requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved when comparing 95% control to routing to a process.**

If EPA adopts routing to a control device as a compliance standard, it must also revise the proposed NSPS OOOOb definition of "self-contained pneumatic device" as follows: "a natural gas-

[59] *See* API Supplemental Proposal Comments § 3.3.2.
[60] 87 Fed. Reg. at 74,765-66.

driven pneumatic controller that releases gas into the downstream piping ~~and not to the atmosphere, resulting in zero methane and VOC emissions~~." EPA must incorporate a similar definition into the EG OOOOc definition. Such a revision is consistent with the State of Colorado's regulations – which define non-emitting to include routed controllers (which in turn include pneumatics routed to combustion). Further, there may be a number of instances where routing a natural-gas driven pneumatic controller into downstream piping routes the gas directly to a flare or control device because the flare or control device is the closest, or only, available destination – *e.g.*, a pneumatic controller on the flare header. EPA should not preclude operators from routing to downstream piping simply due to the proximity to the flare or control device.

As further support for the above, AXPC responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Further, as production declines, there may be insufficient low-pressure gas to keep VRU systems online, leaving pneumatic controller vent gas with no downstream process destination. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. **If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU. In addition, AXPC proposes that an operator need not install a control device for the sole purpose of complying with the pneumatic controller standards if there are less than four individual natural gas-driven pneumatic controllers that emit or may emit vent gas to atmosphere.** This approach is consistent with EPA's proposed natural gas-driven pneumatic pump standards.

In any event, AXPC requests that EPA acknowledge that an acceptable form of process control is to send the natural gas from pneumatics to a tank closed vent system that is primarily controlled by a VRU, capturing and sending that gas down the pipeline. In these situations, there could be a control device also hooked up to the closed vent system, but combusting the tank vapors, and thereby combusting the process gas from the natural gas driven pneumatics, is only happening during non-routine operating times. It should be noted that without a control device, in those instances of VRU downtime, those same emissions would go to atmosphere so use of a control device as a backup to the VRUs is the best option for safety and the environment.

II.D.i.b. The addition of a temporary pneumatic controller should not be a modification under NSPS OOOOb, and temporary pneumatic controllers should be exempt from NSPS OOOOb and EG OOOOc requirements.

EPA defines modification to the pneumatic controller affected facility to occur when the number of pneumatic controllers at a site increases by one or more. AXPC addresses this standard for modification below. While EPA's preamble discussion covers the addition of temporary pneumatic controllers at a location where pneumatic controllers are already subject to NSPS OOOOb or EG OOOOc, it does not address whether the addition of a temporary pneumatic controller – *e.g*., a pneumatic controller associated with a temporary engine – constitutes a modification under NSPS OOOOb. Though temporary controllers should never be subject to NSPS OOOOb or EG OOOOc, the addition of a temporary controller triggering a modification is particularly concerning. As EPA notes in the discussion of its BSER analysis, the required retrofits for existing pneumatic controllers are a significant capital investment – as much as $220,000 to install instrument air systems at remote large systems.[61] Further, requiring operators to track whether temporary equipment has associated pneumatic controllers that may trigger a modification is overly burdensome, especially considering that EPA's proposed EG OOOOc will eventually apply the same control standards as NSPS OOOOb. Operators have limited ability to track temporary equipment, including associated pneumatic controllers, which operators often contract with third parties to install. Further, AXPC understands the lead time for an instrument air skid that might be used to meet the zero emissions standard is currently 22-32 weeks. It is unreasonable to require this amount of planning and lead time to accommodate equipment that will remain onsite for a short period.

EPA requested more detailed information to support the exemption of the zero emissions standard for pneumatic devices on temporary equipment. AXPC is appreciative that EPA realizes that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and gas facilities and that there are cases that warrant an alternative approach. AXPC first notes that incorporating a temporary pneumatic controller into a pneumatic controller system designed to operate with gas other than natural gas – *e.g.*, instrument air, is not feasible in most instances. For example, the existing pneumatic controller system may not be designed to accommodate additional pneumatic controllers and would require retrofitting the gas supply system to increase its capacity. Requiring the costly retrofit of an air supply system to accommodate a temporary operating condition is not cost-effective or practical. Second, to route a temporary pneumatic controller to a process would require significant lead time, an engineering analysis, and a facility shutdown. This would not be cost-effective for a temporary operating condition. As EPA notes in the preamble, Colorado and New Mexico – states paving new ground in pneumatic controller regulation – have both recognized these issues and provide exemptions from zero emissions standards for temporary pneumatic controllers. EPA should follow their lead.

There is precedent for EPA providing exemptions for other temporary oil and gas equipment, and doing so for pneumatic controllers would be consistent with this precedent. For example, EPA exempts temporary skid-mounted or mobile storage vessels from NSPS OOOOa[62] and provides a similar exemption in NSPS OOOOb and EG OOOOc.

AXPC provides the following example case. Operators use large high volume, low pressure (HVLP) separators during flowback activities to comply with the well affected facility completions requirements. This separator is skid mounted and is only used for the first phase of flowback. As an example, one HVLP separator, which can serve six wells, can have two natural gas driven level controllers. It is safer to allow these to be powered by local fuel gas rather than hooking them up to the pad-wide instrument air system because after removal of the separator, abandoned 'stubs' from the pneumatic gas supply line remain in the ground, creating a permanent trip hazard. Further, it forces a wasteful practice to use more materials than necessary and haul out a larger, temporary air compressor for equipment that will be onsite for a limited time. And while this provides a relevant example, AXPC also supports the American Petroleum Institute's comments that NSPS OOOOb and EG OOOOc should not apply to pneumatic controllers during pre-production operations.

[61] *See id.* at 74,767 (Table 27).
[62] 40 C.F.R. § 60.5430a ("storage vessel" definition).

For the reasons stated above, **AXPC requests that EPA clarify the addition of a temporary pneumatic controller at a site is not a modification of the pneumatic controller affected facility under NSPS OOOOb if the temporary pneumatic controller remains onsite for less than 180 days. AXPC further requests that EPA exempt temporary pneumatic controllers (*i.e.*, those that remain onsite for less than 180 days) from the requirements of NSPS OOOOb and EG OOOOc.**

Even for permanent equipment, AXPC notes that it does not agree that a modification should occur at a pneumatic controller facility due to the increase in simply one pneumatic controller. Rather, the number of pneumatic controllers that trigger a modification must warrant the additional capital expenditure at the facility of retrofitting the entire facility to be non-emitting. In most cases, one pneumatic controller addition would not warrant such additional capital expenditure. **Thus, EPA should increase the number of pneumatic controllers that require a modification to a meaningful number that would justify the implementation of retrofits at an existing facility.**

II.D.i.c. <u>EPA should treat new and existing pneumatic controllers differently.</u>

EPA should consider several exemptions for existing pneumatic controllers.

First, EPA does not appropriately consider remaining service life in establishing the non-emitting requirements for existing pneumatic controllers. If EPA had considered remaining service life, it would have identified that based on the normal decline of a well, at some point, natural gas production may decrease below a threshold for which the operator could continue to use natural gas-driven pneumatic controllers. This is because operators typically use natural gas produced from an associated well as the pneumatic gas supply, and where not enough gas is available, the operator can no longer operate the pneumatic controllers without an additional gas supply. In this scenario, an operator would likely replace the natural gas-driven pneumatic controllers with mechanically-driven or other controllers – which will ultimately not have emissions. Requiring the expense of replacing or retrofitting pneumatic controllers at a facility that will not use them for a substantial amount of time is not cost-effective. AXPC believes that EPA has not fully evaluated the cost-effectiveness of retrofitting existing pneumatic controllers because it failed to properly account for decline and changes in the equipment over time. **Thus, EPA should allow exemptions when the remaining service life at the time of the effective date for the requirement is less than 3 years.**

Second, **EPA should allow for the exemption for sites that do not have access to electrical power in the State of Alaska to also apply on a broader basis**. EPA has not completed a comprehensive analysis of which locations, basins, and portions of basins can timely and adequately obtain line power. And even where an area has access to electrical power, landownership and other considerations may either preclude use of line power or substantially delay use of line power. To the extent that EPA denies this request because it believes that solar-powered pneumatic controllers are technically feasible and economically reasonable (which AXPC believes would be inappropriate and refers to the American Petroleum Institute's concerns regarding deployment of solar installations), EPA should provide an exclusion for operators that can demonstrate that solar power may be technically infeasible for parts of the year. **EPA should exempt sites from the zero-emitting requirements (as it did for Alaska) after requiring a demonstration that line power cannot be obtained or cannot be obtained timely based on technical, safety and economic considerations. AXPC supports that anyone obtaining this exemption should have to replace any high-bleed natural gas driven controller with a continuous low-bleed and/or with an intermittent controller and included within a company's LDAR monitoring program to monitor proper functioning.**

Alternatively, AXPC proposes that EPA provide appropriately tailored performance standards for existing pneumatic controllers, similar to the approach proposed for pneumatic pumps, with prioritization to routing emissions to process or control and an offramp if a facility has four or fewer pneumatic controllers.[63]

II.D.i.d. Self-Contained Pneumatic Controllers

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, **EPA could and should allow increased flexibility in implementation of periodic monitoring along this piece of pipe by incorporating these into the fugitive emission monitoring requirements under §60.5397b instead of adding these provisions that are more relevant for covers and closed vent systems as they pertain to storage vessels in §60.5416b(b). EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program when applicable.**

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). **AXPC therefore requests, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.**

II.D.ii. Pneumatic Pumps

First, EPA should define the pneumatic pump affected/designated facility like AXPC proposes to define the pneumatic controller affected/designated facility above. **AXPC requests that EPA define the pneumatic pump NSPS OOOOb affected facility as, "the collection of natural gas-driven diaphragm and piston pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station that emits or has the potential to emit methane or VOC to atmosphere," and similarly define the EG OOOOc designated facility with respect to only methane.** AXPC reiterates its remarks in Section I.A of these Comments, which details why it would be inappropriate to include non-emitting pneumatic pumps in the affected facility definition. Defining pneumatic pumps as AXPC proposes would provide consistency across similar sources, and as noted above, will result in no additional emissions.

Second, for the same reasons as above for pneumatic controllers, **AXPC requests that EPA clarify the addition of a temporary pneumatic pump at a site is not a modification of the pneumatic pump affected facility under NSPS OOOOb if the temporary pneumatic pump remains onsite for less than 180 days.** AXPC incorporates by reference to Section II.D.i.b its comments with respect to pneumatic controller modifications, as the same comments apply to pneumatic pumps.

[63] Note, the reference to four pneumatic controllers here is meant to draw a parallel to EPA's proposed opt out for pneumatic pumps. It is not meant to conflict in any way with the American Petroleum Institute's reference to 15 pneumatic controllers as being the threshold for when retrofitting all existing pneumatic controllers at a location is cost effective. *See* API Supplemental Proposal Comments § 7.5.

Lastly, AXPC notes that existing well sites, centralized production facilities, or compressor stations may not have adequate surface space for the proper placement of instrument air control systems – *e.g.*, due to safety and other permitting constraints. Where this is the case, it would be technically infeasible to utilize a pneumatic pump not driven by natural gas. Accordingly, **AXPC requests that EPA clarify in the final rule text that spacing constraints may pose technical infeasibility - we believe this is consistent with EPA's concepts of physical impossibility (which should be included in technical infeasibility).**

II.D.ii.a. EPA must correct its oversight in EG OOOOc related to natural gas-driven diaphragm pneumatic pumps.

In EG OOOOc, EPA did not explicitly exclude from the pneumatic pump designated facility definition a single natural gas-driven diaphragm pump that operates less than 90 days per calendar year. It appears this is an oversight. In the Supplemental Proposal preamble, EPA explains its intent is for the EG OOOOc pneumatic pump standards to mirror those in NSPS OOOOb.[64] NSPS OOOOb excludes from the pneumatic pump affected facility definition "[a] single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year."[65] EG OOOOc contains no such exclusion; however, EG OOOOc requires that operators maintain records of "[i]dentification of each pneumatic pump that is not driven by natural gas or single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year and is not a pneumatic pump designated facility as specified in §60.5386c(g)."[66] Given the language of this recordkeeping requirement and EPA's statement in the preamble, it seems EPA intends to exclude limited-use natural gas-driven diaphragm pneumatic pumps from the EG OOOOc pneumatic pump affected facility definition.

Accordingly, AXPC requests that EPA add the following subparagraph to §60.5386c(g):

(1) A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not part of a designated facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420c(c)(14)(i). For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.

II.E. Covers and Closed Vent Systems

II.E.i. EPA should not treat emissions from covers and closed vent system as violations.

AXPC supports American Petroleum Institute's (API) comment that EPA should not treat emissions from covers and closed vent systems as violations for the reasons stated in API's comment.[67] AXPC finds particularly persuasive the comment that a "no identifiable emissions" or "no detectable emissions" standard cannot constitute a numerical emissions limitation since BSER must be achievable, meaning the standard must be applied as a work-practice standard. The same equipment at a facility could be a cover or part of a closed vent system or a fugitive emissions component, and there is no reason why a typical fugitive leak from this equipment should be treated any differently simply because it occurs from a cover or closed vent system. Leaks from a cover or closed vent system are not the result

[64] 87 Fed. Reg. at 74,778.
[65] Proposed 40 C.F.R. § 60.5365b(h)(3).
[66] *Id*. § 60.5420c(c)(14)(i).
[67] *See* API Supplemental Proposal Comments § 5.1.

of inadequate design or improper operation and should not constitute a violation of the emissions standard.

II.F. Control Devices

II.F.i. EPA should clarify that operation of a continuous burning pilot is required only when vapors are vented to the control device and allow use of an automatic ignition device in lieu of a continuous burning pilot.

EPA's proposal requires that operators must operate a continuous burning pilot for enclosed combustion devices (ECDs) and flares. **AXPC requests that EPA clarify that operation of a continuous burning pilot is required only when gases are or may be vented to the control device**. EPA's proposed ECD requirements require operators to ensure flow to the control device is at or above the control device's minimum inlet gas flow rate.[68] To ensure compliance with this requirement, operators may install a, "backpressure preventer" (*see* Section II.F.ii.h of these Comments for discussion on backpressure preventers) at the control device inlet to prevent flow to the device that is below the device's minimum inlet flow rate. Where operators use this configuration, EPA's Supplemental Proposal would require operation of a continuous burning pilot during times when no vapors are vented to the control device. For low or intermittent vapor control streams, the "backpressure preventer" may remain closed for much of the time while pressure builds up to ensure requisite inlet vapor flow rate when the control valve opens. In this scenario, the result is that much of the continuous burning pilot's operation may occur when vapors are not vented to the control device, creating an environmental disbenefit. While not required for flares, if an operator installed a control valve at the inlet to the flare, it could similarly monitor when vent gas is going to the flare for combustion.

AXPC proposes that EPA clarify operation of a continuous burning pilot is required only when vapors are routed to the control device. Further, AXPC requests that EPA allow operators to use an automatic ignition device in lieu of a continuous burning pilot, which would avoid unnecessary combustion altogether, as use of an automatic ignition device would ensure combustion occurs when vapors are routed to the control device. **Where an operator chooses to operate a continuous burning pilot or automatic ignition device only when vapors are vented to the control device, AXPC proposes the operator would monitor the inlet valve of the control device to demonstrate that the control device was operated with a continuous burning pilot or automatic ignition device when the inlet control valve is open and allowing the passage of vapors to the control device.**

II.F.ii. Monitoring and Performance Testing Requirements

II.F.ii.a. EPA should not require operators to start up control equipment to conduct performance testing.

Where operators must conduct periodic performance testing – *e.g.*, Method 22 tests or performance testing, **AXPC requests that EPA clarify that an operator need not startup a source for the sole purpose of performing testing or monitoring**. Requiring operators to startup up emissions sources to avoid missing a periodic testing event would result in emissions that would otherwise not occur, which is counterproductive to the emissions reduction goals of EPA's Proposal. EPA should provide

[68] Proposed 40 C.F.R. §§ 60.5412b(a)(1)(vi), .5412c(a)(1)(vi).

operators with a reasonable amount of time following the affected/designated source's return to service to perform testing that became due while the source was out of service – *e.g.,* 30 days.

II.F.ii.b. Net Heating Value Monitoring

For certain enclosed combustion devices (ECDs) and flares, EPA proposes that operators maintain the net heating value (NHV) of vent gas sent to the device above applicable minimum NHV limits. Where this requirement applies, EPA proposes that operators continuously monitor the control device's inlet gas stream using a calorimeter to demonstrate the inlet gas is above the applicable NHV limit. Alternatively, to avoid continuous monitoring, EPA allows operators to demonstrate inlet gas consistently exceeds the applicable minimum NHV by continuously monitoring the inlet gas stream for 10 consecutive days. Both the requirement to continuously monitor inlet gas NHV and the alternative demonstration to avoid continuous NHV monitoring are costly and onerous and, most importantly, unnecessary in most instances under EPA's Supplemental Proposal.

First, the vast majority of applicable vent gas streams are consistently above applicable minimum NHV limits. Particularly for upstream facilities, these vent gas streams are typically high in methane, ethane, and VOC content – typically 95+%, meaning the NHV of these streams is usually at or above 1,000 Btu/scf, and often much higher. The highest NHV low limit for an enclosed combustion device or flare is 800 Btu/scf,[69] which is significantly below the expected NHV for most vent gas streams and limited to pressure-assisted devices. Non-pressure assisted flares and ECDs are subject to minimum NHV limits of 200 – 300 Btu/scf, which is well below the typical NHV of an oil and gas vent stream. In addition, unlike a refinery, operators do not use inert gases that would reduce the inherently high NHV of a vent gas stream. Thus, there is little risk, and in many cases no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant costly and onerous continuous NHV monitoring.

Second, the use of calorimeters in the upstream oil and gas sector is unproven. The variable nature of production flowrates results in low and/or intermittent vapor control streams. Current calorimeter technology cannot accurately measure the NHV of these low and/or intermittent streams consistently over time and across varying operating conditions. In these applications, calorimeters are unlikely to yield accurate or useful data. In addition to the technical concerns, the Proposal will prompt thousands of calorimeter orders that will overwhelm calorimeter supply vendors, resulting in a supply chain crisis, as operators wait months or longer for order fulfillment. One of the most prominent calorimeter manufacturers in the United States estimates current supply can only be met for 6 to 10 units per month at a cost of $70,000 to $120,000 per unit (average $100,000). Large operators may have one thousand or more flares that would require monitoring under NSPS OOOOb or EG OOOOc. In addition to this large capital expense, there would be additional demands on the site infrastructure, such as the use of instrument air systems required to operate the calorimeter.

Third, engineering methodologies (*e.g.*, engineering simulation software) can accurately estimate the heat value of vent gas streams where a representative analysis serves as the basis for the estimation. These data combined with operating parameters and production will provide an accurate estimate of heat value as well as vent gas volume through the use of long understood equations of state – *e.g.*, Peng-Robinson, 1976. These methods are used for permitting and are a method listed in 40 CFR § 98.233 "Onshore production and onshore petroleum and natural gas gathering and boosting storage"

[69] *See id.* §§ 60.5412b(a)(1)(iv), .5412b(a)(3)(i), .5412c(a)(1)(iv), .5412c(a)(3)(i).

Calculation Method 1 for Subpart W Greenhouse Gas estimations. Therefore, EPA should allow operators the option to use engineering methodologies to demonstrate a vent gas stream will remain above the minimum NHV limit.

Further, calorimeter installation and maintenance require a skilled labor force that is insufficient in supply today to meet the needs of EPA's Supplemental Proposal. It would take years to recruit and train this labor force. The combination of equipment and labor supply shortages will force operators into a position where compliance is simply infeasible by compliance deadlines.

The solution to these issues is simple. Given the low risk that control device inlet gas streams would fall below an applicable NHV limit, the technical issues, and the equipment and supply issues, **AXPC proposes that EPA allow operators to demonstrate the inlet stream to a combustion control device meets the applicable minimum NHV limit requirement by using a pressurized liquids analysis in combination with engineering software**. Under this approach, the operator would pull a pressurized liquids sample from a separation vessel, or use a representative pressurized liquids sample, and input the sample results into engineering software configured to estimate with a high degree of accuracy the net. **If the engineering analysis demonstrates the NHV is within 200 Btu/scf of an applicable NHV limit, AXPC proposes that the operator must then comply with the proposed NHV continuous monitoring requirements or the alternative to continuous NHV monitoring**. AXPC proposes 200 Btu/scf, as this value exceeds the 20 percent cushion of the highest potentially applicable NHV limit EPA that notes as being "well above the threshold."[70]

Regarding the alternative NHV demonstration, **AXPC supports American Petroleum Institute's proposed revisions which would require a minimum of two (2) hourly samples or two (2) hours of continuous monitoring per day for seven (7) days for a total of 14 samples.[71] AXPC believes this method is sufficient to demonstrate the anticipated NHV will remain above the applicable minimum NHV limit.**

II.F.ii.c. Method 22 Tests

EPA proposes monthly Method 22 tests for enclosed combustion devices (ECDs) and flares used to comply with various provisions within the Proposal. On the scale and scope of sources this Proposal will cover, this monthly requirement is overly burdensome. **As an alternative, AXPC proposes that operators evaluate and document whether the control device is smoking or not smoking at least once per week, and if the operator observes smoke emanating from a control device, a Method 22 test will be completed within 12 hours to determine if visible emissions are occurring. Further, AXPC proposes to complete at least one Method 22 test in each semiannual period.**

AXPC estimates each 15-minute Method 22 test will require 0.5 hours to 3 hours to complete, which includes travel time, set up time, the observation period, documentation of the procedure, document quality review, organization, and filing for reporting. AXPC anticipates the vast majority of Method 22 tests will find no visible emissions, meaning operators may spend thousands, if not millions, of hours observing properly operating control devices. AXPC's proposal, in requiring weekly control device observation, ensures frequent control device evaluation and focus efforts where visible emissions might be occurring – *i.e.*, when the operator observes smoke from a control device. AXPC operator experience is that a combustion device will smoke frequently or continuously if the device will not pass a

[70] 87 Fed. Reg. at 74,795.
[71] *See* API Supplemental Proposal Comments § 5.6.4.

Method 22 test, meaning the operator is likely to observe smoke from a control device with visible emissions while on location, which would require conducting a Method 22 test under AXPC's proposal.

AXPC proposes that operators conduct a Method 22 test within 24 hours of smoke observation, rather than contemporaneous with smoke observation, as the personnel that most often visits an oil and gas location may not have sufficient training or expertise to conduct a Method 22 test. 12 hours provides operators sufficient time to mobilize personnel trained in Method 22 testing.

If EPA does not adopt AXPC's proposal, AXPC requests that EPA reduce the minimum spacing between consecutive Method 22 tests from 15 days to seven (7) days. The requirement to conduct a Method 22 test approximately every 30 days (assuming a 30-day month), but no more frequently than every 15 days is an overly burdensome administrative requirement, as operators would have a small window to schedule Method 22 tests for potentially thousands of control devices. Providing for tests no more frequently than every 7 days would significantly reduce this administrative burden while ensuring sufficient operational periods between tests to evaluate control device performance over potentially varying operational conditions, to the extent variability exists.

Lastly, given the tremendous burden of conducting monthly Method 22 tests for thousands of control devices, **AXPC requests that EPA allow use of alternative monitoring technologies – *e.g.*, a fixed, stationary camera technology that continuously monitors for presence of visible emissions**.

II.F.ii.d. <u>EPA should allow operators to monitor control device inlet pressure in lieu of monitoring flow.</u>

Existing flow meter technology cannot accurately measure flows that are generally of low velocity with intermittently high velocity, and data obtained from a flow meter in this application will be inaccurate and misleading. For example, gas flow from a typical storage vessel into a closed vent system (CVS) predominantly results from flashing vapors, which significantly outweigh the volume of working and standing emissions that occur between flashing events. The normal volumes from working and standing losses are typically at very low velocity, which is difficult to measure with current technology, whereas the volume associated with flashing vapors is typically higher. Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero or very low flow to maximum flow in milliseconds and be able to go back to zero or very low just as quickly. The hysteresis (*i.e*., the amount that the previous state impacts the future state) and the latency (*i.e.*, the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients.

Further, differing gas composition may reduce the accuracy of flow meters, which are calibrated to a specific gas composition. AXPC anticipates that many of the oil and gas flares and ECDs will control storage vessels, and the composition of storage vessel gas varies depending on the conditions in the vessel. For example, flash gas vapor has a different composition (more lighter end carbon chain hydrocarbons) than working and breathing emissions (more heavier end carbon chain hydrocarbons). Because of this variable gas composition, a flow meter installed to measure storage vessel vapor flow cannot be calibrated to accurately measure all types of storage vessel vapor flow.

For the above reasons, flow monitors are not uniformly capable of accurately monitoring flow rate in subject natural gas streams.

As an alternative, operators can install and operate a pressure monitor at the inlet to a combustion control device to demonstrate inlet flow to the control device is within the device's design range. AXPC understands that pressure monitors are not plagued by the issues noted above and can achieve reasonably accurate measure of pressure more readily than flow monitors can measure flow.[72] Moreover, combustion control device manufacturers typically provide design capacity curves in terms of pressure, rather than flow. In other words, pressure correlates directly to combustion control device performance and is an appropriate parameter to monitor for demonstrating proper operation of a control device. It is not clear whether EPA intends to allow the use of a pressure monitor. §§60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D) allow for the use of "other parameter monitoring systems combined with engineering calculations." Because combustion control device performance directly corresponds to the device's operating pressure, no further engineering calculation is necessary.

Accordingly, AXPC proposes that EPA allow operators to monitor inlet pressure to a combustion control device to demonstrate the device is operating within its design capacity without further engineering calculation, or clarify that §§60.5417b(d)(vii)(A), (d)(viii)(D) and 60.5417c(d)(vii)(A), (d)(viii)(D) allow the use of a pressure monitor in lieu of a flow monitor for all applicable control devices (whether manufacturer or owner tested). Consistent with this request, AXPC provides the following redline of §§60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D):

> **You may use direct flow meters, direct pressure monitors, or other operating parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement.**

AXPC provides the following redline of §§60.5417b(d)(vii)(A) and 60.5417c(d)(vii)(A):

> **The continuous parameter monitoring system must measure gas flow rate or pressure at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate or pressure at the inlet to the combustion device must be equal to or greater than the minimum flow rate or pressure and equal to or less than the maximum flow rate or pressure determined by the manufacturer.**

II.F.ii.e. <u>AXPC requests that EPA confirm its intent is to exempt properly designed facilities from the requirement to monitor control device inlet flow.</u>

For flares and enclosed combustors (ECDs), EPA generally proposes to require operators to monitor inlet flow or other parameters to demonstrate the control device is operating within its design capacity – both minimum and maximum. However, where an operator can demonstrate, "based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system," the maximum flow to a flare or ECD cannot exceed the ECD's established maximum flow rate or the flare tip velocity limit in §60.18, the operator is exempt from monitoring maximum inlet flow rate, and for flares, from the requirement to monitor inlet flow or other parameters.[73] Similarly, if the operator installs a "backpressure preventer" (*see* Section II.F.ii.h. of these Comments) "which is set to operate at or above the minimum inlet gas

[72] *See* Appendix 1 of these Comments (providing example manufacturer design specification of a combustion control device model – Cimarron CEI 1-48 – approved by EPA as meeting the combustion control device performance requirements in NSPS Subpart OOOO and NESHAP Subparts HH and HHH).
[73] Proposed 40 C.F.R. §§ 60.5417b(d)(viii)(*1*)-(*3*), .5417c(d)(viii)(*1*)-(*3*).

flow rate" of an ECD, the operator is exempt from the requirement to monitor for minimum inlet gas flow rate. **Said another way, if the operator designs its control system to prevent the possibility of inlet flow to a flare or ECD being outside of its design capacity range, the flare or ECD is exempt from flow monitoring requirements. AXPC requests that EPA confirm this statement is consistent with its intent.**

As noted below, AXPC requests EPA revise the inlet flow monitoring requirements for ECDs performance tested by the manufacturer to be consistent with the flow monitoring requirements for ECDs performance tested by the operator and intends the above discussion and request apply equally to all ECDs.

II.F.ii.f. <u>Enclosed Combustion Device Performance Testing</u>

Recent experience in Colorado demonstrates that performance testing enclosed combustion devices (ECDs) is infeasible without the use of supplemental gas for ECDs that control intermittent vapor streams – *e.g.*, storage vessel vapor streams. Where flow is intermittent, obtaining a single one-hour run, much less three,[74] is infeasible without use of supplemental gas. For example, in many storage vessel systems, emissions occur in batches as the upstream separator dumps pressurized liquids into the storage vessel in batches by design, with each batch resulting in short duration flashing emission events. In most storage vessel systems, these flashing emission events momentarily increase storage vessel pressure, which is then reduced by routing emissions to the control device. In these systems, flow to the ECD is intermittent and insufficient to maintain constant flow to the ECD to facilitate a one-hour run for a performance test, even where the storage vessel services a newly drilled well. Installation of a backpressure preventer to ensure inlet flow to the ECD is above the device's minimum flow rate – a compliance option in EPA's Proposal – will only exacerbate this issue, as a backpressure preventer ensures intermittent emissions flow to the ECD. **Accordingly, AXPC requests that EPA either exempt ECDs from performance testing where normal inlet flow to the ECD is insufficient to facilitate a performance test or clarify that operators may use supplemental gas to facilitate the performance test.**

II.F.ii.g. <u>Manufacturer-tested enclosed combustion devices should have the same flow monitoring requirements as other enclosed combustion devices.</u>

AXPC requests that EPA provide the same continuous flow monitoring alternatives for all enclosed combustion devices (ECDs). For ECDs performance tested on-site, EPA proposes that operators measure flow directly with a flow meter or "other parameter monitoring systems combined with engineering calculations."[75] EPA provides alternatives to these requirements where (1) for maximum inlet flow rate, the operator can demonstrate the maximum flow rate to the ECD cannot cause exceedance of the ECD's maximum inlet flow rate, or (2) for minimum inlet flow rate, the operator installs and operates a "backpressure preventer which is set to operate at or above the minimum inlet gas flow rate."[76] EPA does not propose these flow monitoring alternatives for ECD models that are performance tested by the manufacturer.

The monitoring of an ECD's inlet flow is physically indistinguishable among devices performance tested by a manufacturer or the operator because the performance test does not impact inlet flow rate

[74] *Id.* §§ 60.5417b(b), .5417c(b).
[75] *Id.* §§ 60.5417b(d)(1)(viii)(D), .5417c(d)(1)(viii)(D).
[76] *Id.* §§ 60.5417b(d)(1)(viii)(D)(*1*)-(*3*), .5417c(d)(1)(viii)(D)(*1*)-(*3*).

characteristics. Rather, as the Proposal requires, the performance test establishes, among other things, a minimum and maximum flow rate within which the device will meet requisite emissions reduction requirements. This range has no bearing on whether the operator can demonstrate the maximum flow to the ECD will remain below the maximum flow rate established in a performance test, and a "backpressure preventer" (*see* Section II.F.ii.h of these Comments) will perform the same across all ECDs to ensure flowrate to an ECD remains above the minimum flow rate established in a performance test. Accordingly, **AXPC requests that EPA provide manufacturer-tested ECDs the same alternatives to flow monitoring as ECDs tested by the operator.**

II.F.ii.h. <u>"Backpressure Preventer"</u>

EPA provides an alternative to control device inlet flow monitoring where the operator installs and operates "a backpressure preventer which is set to operate at or above the minimum inlet gas flow rate."[77] EPA does not, however, define the term "backpressure preventer," and AXPC is not aware that such a device exists. However, AXPC believes EPA intends to mean a control valve installed at the inlet to a control device that is set to remain open when the inlet pressure to the control device is at or above the device's minimum inlet gas flow rate. **Accordingly, AXPC proposes that EPA revise §§60.5417b(d)(viii)(D)(*2*) and 60.5417c(d)(viii)(D) (*2*) as follows:**

> **If you install and operate ~~a backpressure preventer~~ control valve which is set to ~~operate~~ remain open only at or above the minimum pressure corresponding to the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.**

II.F.iii. <u>Flares</u>

II.F.iii.a. <u>60.18(b) Demonstration</u>

As a threshold matter, EPA should clarify its intent with respect to demonstrating initial flare compliance, which requires compliance with 40 C.F.R. § 60.18(b). The proposed §§60.5412b(a)(3) and 60.5412c(a)(3) each provide, in part:

> Each flare must be designed and operated according to the requirements of §60.18(b) as specified in paragraphs (a)(3)(i) through (iv) of this section.
>
> (i) You must use Method 18 of appendix A-6 of this part to determine the NHV of the vent gas meets the requirements in §60.18(c)(3)(ii). For pressure-assisted flares, in lieu of the heating value limits in §60.18(c)(3)(ii), the NHV of the gas being combusted must be 800 Btu/scf or greater.

§60.18(b) identifies that flares must comply with §60.18(c)-(f). §60.18(c)(3) provides operators a choice to adhere to heat content specifications in §60.18(c)(ii) and the maximum tip velocity specifications in (c)(4), or to adhere to the requirements in (c)(3)(i). In EPA's proposal above, it is unclear whether EPA intends that operators do not use the compliance option in §60.18(c)(3)(i). **AXPC requests that EPA clarify its intent with respect to how operators are to comply with §60.18(c), as referenced by §60.18(b)**.

[77] *Id.* § 60.5417(d)(1)(viii)(D)(*2*).

II.G. Collection of Fugitive Emissions Components

II.G.i. EPA must revise the fugitive emissions component definition with respect to in yard piping and thief hatches or other openings on a storage vessel.

EPA proposes to define "fugitive emissions component" to include "in yard piping" and "thief hatches or other openings on a storage vessel not subject to §60.5395b [or §60.5411c for EG OOOOc]."

Regarding in yard piping, **AXPC proposes that EPA exclude buried in yard piping from the definition of fugitive emissions component**. Buried in yard piping will remain difficult to monitor – in fact, impossible to monitor – so long as it remains buried. As proposed, difficult and unsafe-to-monitor equipment designations are available only where the operator monitors using Method 21, and for difficult-to-monitor equipment, an operator must monitor at least once per calendar year. AXPC expects most operators to utilize OGI cameras, which have no difficult or unsafe-to-monitor equipment designation. Operators cannot ever monitor buried components and thus cannot comply with the requirement to monitor buried in yard piping, even on an annual basis if designated as difficult-to-monitor.

Regarding storage vessels, **EPA's fugitive emissions component definition should exclude thief hatches and other openings on storage vessels not subject to any vintage of NSPS OOOOa/b/c, as these regulations would include cover and closed vent system requirements that apply to this equipment**, which AXPC understands is the basis for EPA excluding this equipment from the requirement cited in the proposed definition. Additionally, **EPA should clarify that a thief hatch or other opening on an uncontrolled storage vessel is not a fugitive emissions component**, as it did in NSPS OOOOa. Uncontrolled storage vessels are designed and intended to emit to atmosphere and may do so through thief hatches or other openings. It is illogical for the observance of allowable and intended emissions from this equipment to trigger repair requirements.

II.G.ii. Well Closure Plan

EPA proposes "well closure requirements" as part of NSPS OOOOb/c. Before AXPC discusses its concerns with EPA's well closure requirements as drafted, AXPC notes that EPA has articulated the purpose of the well closure requirements. Specifically, EPA has noted that idled or temporarily abandoned wells can continue to have emissions leaks (and according to EPA certain leaks can be substantial). Thus, EPA believes that it is important that operators continue fugitive emissions monitoring until the well has been plugged and abandoned – and that at such time an operator may cease fugitive emissions monitoring. As a result, the well closure requirements in EPA's proposal are intended to reflect the point in time at which an operator may discontinue compliance with the fugitive emissions monitoring requirements.[78]

As an initial matter, AXPC supports EPA's requirement that fugitive emissions monitoring continue until the well is plugged and abandoned. However, as written EPA's proposal goes well beyond the stated purpose and raises significant questions about EPA's legal authority to implement the proposal as written. Importantly, **AXPC believes that EPA should rely upon the existing plugging and**

[78] 87 Fed. Reg. at 74,736.

abandonment procedures in each state in determining when such plugging and abandoning has occurred.

First, each oil and gas state has different and specific rules regarding plugging and abandonment. However, in each state that AXPC members operate in, the relevant oil and gas commission or department, has existing procedures relating to plugging and abandonment. Importantly, those regulations typically define when plugging and abandonment must occur, the notification requirements for plugging and abandonment and the requirements that must be followed in plugging and abandoning a well. Further, states also typically have existing provisions and requirements regarding financial assurance (typically put in place well before abandonment of the well is contemplated). EPA's proposed well closure plan does not consider these existing frameworks and may contradict these existing frameworks – among other problems.

Second, EPA's proposed language regarding well closure could be interpreted to require submission of a well closure plan any time a well has been shut in for more than thirty (30) days. Specifically, EPA's regulations state "[y]ou must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site." EPA does not define cessation of production. However, there are a number of instances or reasons that a well could cease production for 30 days without that well being a candidate for closure. Nothing in EPA's preamble suggests that EPA is intending to use (or even legally could use) these well closure plan requirements to mandate the plugging and abandonment of wells. EPA's preamble makes clear that EPA simply intends to have written confirmation of plugging and abandonment of the well before an operator may cease fugitive emissions monitoring. Fortunately, EPA does not need to create a new well closure plan to obtain this information. Rather, **EPA should simply require the submission of written materials required by the relevant jurisdiction reflecting the plugging and abandonment of the well**. Once these materials have been submitted, then an operator may cease fugitive emissions monitoring. Relying upon the required reporting to state oil and gas commissions is appropriate and has been relied upon for many years for reporting of well completion operations under OOOO/a.

To the extent EPA retains the requirement to submit a well closure plan within 30 days of cessation of production of all wells located at a well site, EPA should clarify submittal of the plan is triggered by the operator's intent to <u>permanently</u> cease production at all wells at a well site. As noted above, operators may temporarily cease production at a well site over the life of the site. Given EPA's intent is to ensure periodic fugitive emissions monitoring occurs until a well is plugged and abandoned, it would be consistent with EPA's intent to require submittal of a well closure plan only when the operator plugs and abandons all wells at a well site. Until such time as the operator completes the final monitoring survey to confirm no emissions following plugging and abandonment, the operator must continue to conduct leak monitoring surveys at the appropriate frequency. AXPC's proposal would not change this requirement.

II.G.iii. <u>AXPC supports API's proposal of quarterly AVO inspections, with no OGI inspections, for all wellhead only sites.</u>

AXPC agrees with and supports the American Petroleum Institute's (API) comment that wellhead only sites (single or multiple) should be subject to quarterly AVO inspections and no OGI inspections for the reasons stated in API's comment letter.[79] While AXPC believes that quarterly AVO

[79] *See* API Supplemental Proposal Comments § 2.1.

inspections are the appropriate frequency for all wellhead only sites, bimonthly AVO inspections only would be acceptable as the monitoring frequency for multi-wellhead only sites.

In addition to API's comments, AXPC offers the following support. Wellhead only sites generally have less fugitive emissions components, and wellheads are constructed with thicker, higher pressure-rated iron causing flanges to be larger such that AVO inspections are able to reliably detect any leaks that may occur. In addition, quarterly AVO requirements would allow operators to train field personnel who are already familiar with sites to conduct AVO inspections during their routine rounds. For these reasons, quarterly AVO inspection of wellhead only sites would be an effective and economic means to monitor for leaks at wellhead only sites.

II.G.iv. <u>Quarterly OGI surveys should be spaced every 30 days apart.</u>

EPA's proposed §60.5397b(g)(1)(iii)(F) requires spacing consecutive quarterly OGI/Method 21 monitoring surveys at least 60 days apart. Due to safety issues and facility availability, 60 days is too restrictive. Further, requiring spacing inspections at least 30 days apart will allow for inspection across varying operating conditions. **For these reasons, AXPC requests that EPA reduce the §60.5397b(g)(1)(iii)(F) OGI/Method 21 inspection survey spacing from 60 days to 30 days.**

II.H. <u>Storage Vessels</u>

II.H.i. <u>"Modification" Definition</u>

In defining "modification" for storage vessels, EPA proposes to depart from the §60.14 "modification" definition and instead define a storage vessel "modification" as follows.

> "Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through (D) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.
>
> (A) A storage vessel is added to an existing tank battery;
>
> (B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases;
>
> (C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).
>
> (D) For tank batteries at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (*i.e.*, prior to an action in paragraphs (e)(3)(ii)(A), (B) or (D) of this section) determination of the potential for VOC or methane emissions.

AXPC proposes that EPA limit modifications to where the operator increases emissions from the tank battery by increasing the capacity of the tank battery. As proposed, subparagraphs (A) and (B) would trigger a potential modification even where the increase in capacity of the tank battery is not accompanied by an increase in the tank battery's emission rate. AXPC's proposal would ensure consistency with §60.14 by requiring a capital expenditure on the potential affected facility accompanied by an increase in emissions. Further, operators may readily track and document the addition or replacement of storage vessels within a tank battery.

If EPA does not define "modification" to require an increase in the emissions rate of the tank battery, perverse outcomes may occur. For example, an operator may increase the size of tank battery without increasing the emissions from the tank battery, and if the emissions – which have not changed – exceed the applicability threshold, the tank battery would become an affected facility. This possibility is real given that EPA now proposes to apply the 6 tpy VOC and 20 tpy methane applicability thresholds to the entire tank battery, where it previously under NSPS OOOO and OOOOa used the same VOC threshold but on an individual storage vessel basis. This shift effectively reduces the NSPS applicability threshold proportionally by the number of individual storage vessels in a tank battery.

AXPC believes the proposed criteria in subparagraphs (C) and (D) regarding increases in liquid throughput are too broad and are inconsistent with §60.14(e)(2). Per § 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as operators typically track liquid throughput using tank gauging rather than flow meters. Further, subparagraph (C) serves as a disincentive to the centralization of facilities, as the addition of production from a new well to an existing centralized production facility would trigger a modification under subparagraph (C). Due to this disincentive, the historic understanding of modification, and the practical challenges of tracking liquid throughput, **AXPC believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification**. To the extent that EPA retains these subsections in the final rule, **the increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself. These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would retain consistency with §60.14.

If EPA retains subparagraph (C), EPA should provide several clarifications. First, EPA proposes that a modification occurs where an added process unit increases storage tank battery throughput. This provision concerns well sites and centralized production facilities and not facilities that process natural gas. EPA defines process unit as components assembled for the purpose of extracting natural gas liquids from field gas and other gas processing-related activities, which by definition, would not occur at a well site or centralized production facility. Thus, reference to process unit in the context of well sites and centralized production facilities is confusing and misplaced. **AXPC requests that EPA remove reference to "process unit" from this subparagraph (C)**.

If EPA retains the current modification definition (which for all the reasons stated above, AXPC believes EPA cannot and should not), EPA must limit the actions that may trigger modification of tank batteries at well sites or centralized production facilities to actions taken with respect to equipment that provides liquid throughput to the storage vessels in the tank battery. For example, hydraulic fracturing activities occurring in the vicinity of a well that delivers produced liquids to a storage tank battery may temporarily increase production of the well, which would, in turn, increase throughput of the tank battery. As drafted, it is unclear whether this increase in production is an "action" that modified the tank battery if it resulted in exceedance of the potential for emissions threshold. It should not. Operators cannot plan for or anticipate increases in production from activities occurring off-site that are outside the scope of operations associated with the tank battery. Further, in this example, the cause of a temporary increase in production may be unknown to the operator. Considering "actions" having no direct relationship to equipment in the definition of modification would be a far and extreme departure from longstanding NSPS modification principles. Accordingly, **EPA should limit the scope of this subparagraph (C) to "actions taken with respect to equipment that directly, or through a series of equipment, provides crude oil, condensate, intermediate hydrocarbons, or produced water throughput to the tank battery, including the addition of, or change to, a production well (including hydraulic fracturing or refracturing of the well)."**

If EPA retains these modification triggers, well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants. EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. This recommendation would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Regarding subparagraph (D), **AXPC requests that EPA clarify that it does not intend for operators to maintain records of potential emissions calculations for any of the actions in §60.5365b(e)(3)(ii)(A) through (D) that do not result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in §60.5365b(e)(1)(i) or (ii)**. If one of these actions does not result in the potential for VOC or methane emissions to exceed the storage vessel applicability threshold, then a modification did not occur, and NSPS OOOOb would not apply, including recordkeeping requirements. This is not clear in the Supplemental Proposal.

Lastly, **AXPC requests that EPA clarify that the storage vessel "modification" definition in §60.5365b(e)(3)(ii) is the singular controlling "modification" definition for NSPS OOOOb storage vessel affected facility determinations and that the modification definition in §60.14 does not apply**.

II.I. Liquids Unloading

In the 2021 Proposal, EPA solicited input on a number of considerations associated with well liquids unloading. And stakeholders submitted a number of comments on EPA's proposal regarding well liquids unloading. AXPC appreciates the following changes or clarifications by EPA: (1) clarification of that the liquids unloading requirements apply to gas wells; (2) removing the overly expansive modification trigger for well liquids unloading; and (3) removal of "design" as the determination of whether a well liquid unloading activity must comply with the requirements.

Despite these revisions, AXPC continues to have concerns with the well liquids unloading proposal and requests several changes.

First, **EPA should not require recordkeeping or reporting for each well liquid unloading operation conducted during the year unless EPA has defined well liquid unloading operation to mean only those well liquid unloading operations intended to vent to atmosphere**. As noted in APXC's Prior Comments, AXPC supported EPA's original "Option 2" and continues to feel strongly that EPA's Option 1 (selected in the Supplemental Proposal by EPA) has significant practical and legal implications. As EPA recognizes in its supporting documentation, one primary methodology that may be used to reduce or eliminate venting from removal of liquids of gas wells is a plunger lift. In most operational scenarios, a plunger lift will assist with liquid removal from the wellbore without any venting to the atmosphere. The plunger lift will operate on either a set cycle or may operate based upon pressures reflected in the well bore. However, not all plunger lifts are designed to or have the necessary equipment on site to track each and every cycle of the plunger lift. Thus, EPA's proposal could require installation of equipment to track the plunger cycles while providing no emissions reductions benefits. EPA has not fully evaluated the cost of installing and operating such tracking equipment in its cost-benefit analysis, and given that there will be no emissions benefits, EPA cannot show that such a requirement would be cost-effective. This is but one example. Additionally, even where equipment is available to track the number of wellbore liquids removal events that do not vent to atmosphere, the operational costs of undertaking that tracking are considerable and the data collected will be significant. EPA has provided no reasonable explanation for its need to obtain and track data relating to the number of wellbore liquids removal events that do not vent to atmosphere. And EPA provides virtually no explanation for its decision to stick with Option 1, other than the fact that "malfunctions" can result in vented emissions from liquids removal operations that would otherwise meet the zero emissions standard. EPA has no basis for concern with respect to malfunctions as it has implemented a robust AVO and OGI inspection program that would be expected to identify wells that have emissions during liquids removal that were not expected or intended. In Section I.A of these Comments, AXPC provides discussion of why EPA cannot define an affected facility to include equipment that is not intended to emit methane and/or VOC.

One simple solution to this problem is to define well liquids unloading to mean only those wellbore liquids removal events that are intended to vent to atmosphere. By defining well liquids unloading in such a manner, EPA will encourage operators to find solutions that eliminate venting and will ensure that operators not only implement certain emission reduction requirements to reduce venting to atmosphere, but also record and report on those instances that do result in venting to the atmosphere.

Second, by defining well liquids unloading events to mean only those wellbore liquid removal events that are intended vent to atmosphere, EPA would avoid regulating events or operations that do not have any emissions to atmosphere. Such a framework is much more consistent with EPA's legal authority – which does not extend to equipment or operations that do not have emissions releases**. In connection with this creation of a definition for well liquids unloading event, EPA should eliminate use of the term zero emissions or zero emissions standard in reference to wellbore liquids removal.** AXPC notes that API recommends removal of the requirement to demonstrate that an operator cannot preclude venting to the atmosphere.[80] AXPC supports that position. However, **if EPA retains those requirements, then EPA should only require: (1) maintaining documentation that the operator cannot preclude venting to the atmosphere due to technical, safety or economic considerations; and (2) the implementation of Best Management Practices (BMPs) where that demonstration has been made.** Importantly, AXPC believes that wellbore liquids removal operations that are routed to combustion device or a flare do not "vent to atmosphere." In fact, routing emissions from wellbore liquids removal operations to a combustion device or a flare may (in certain circumstances) be the best mechanism to reduce emissions from well liquids unloading. By using the term "zero emissions," which EPA has indicated in other contexts that combustion devices do not fall into, EPA has limited the value and usefulness of this control methodology. Thus, AXPC strongly believes that wellbore liquids removal

[80] *See* API Supplemental Proposal Comments § 9.3.

operations that are routed to a combustion device should not be considered to be venting to the atmosphere, and under AXPC's proposal, would not be considered well liquids unloading. EPA should clarify in the final rule that well liquids unloading being routed to a control device is not intended to vent and thus not subject to the well liquids unloading requirements.

Third, EPA must revise the language in the regulations to be consistent with its preamble. In the preamble, EPA states that: "for wells that utilize methods that vent to the atmosphere, the proposed rule would require: (1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety or economic reasons…." However, EPA appears to have inadvertently failed to include "economic" considerations in the rule language. The rule language currently references only "technical or safety reasons." **Consistent with EPA's preamble, EPA should revise the rule to reference "technical, safety, or economic reasons."** The inclusion of "economic" is also critical in light of the framework for the New Source Performance Standards. AXPC provides additional discussion of economic considerations in BESR in Section I.B of these Comments.

II.J. <u>Reciprocating Compressors</u>

AXPC generally supports the inclusion of requirements for reciprocating compressors in NSPS OOOOb and EG OOOOc, with the following comments and exceptions.

As an initial matter, AXPC notes that **the proposed regulatory text in §60.7370b(a)(1)(iii) includes a reference to §60.5385b(a)(3) – a provision which does not exist**. **AXPC requests that EPA correct this error.**

Regarding the proposed standard, EPA should clarify in the regulation its intent that the 2 scf/minute (scfm) threshold applies to each compressor cylinder (also known as a "throw"). EPA's preamble to the Supplemental Proposal states that "[t]he volumetric flow rate measurement from *each reciprocating rod packing* must be maintained to be less than or equal to a flow rate of 2 scfm." And EPA's description of how reciprocating compressors may result in leaks (that the affected facility requirements are designed to address) states that "over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking <u>from the compression cylinder</u>." And in the November 2021 Notice, EPA's preamble language made clear that it applied to each individual cylinder. Specifically, EPA stated in the November 2021 Notice that "[w]e are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing." And, importantly, EPA does not describe any intent to have changed where the 2 scfm is measured in its preamble to the Supplemental Proposal. That it applies to each cylinder is supported by EPA's description of how reciprocating compressors work, its description of flow through the compression cylinder, and its description that "the rod packaging system needs to be replaced to prevent excessive leaking from the compression cylinder." Unfortunately, EPA's proposed regulation simply states: "[t]he volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm)." Without revision, this could be confusing and less than clear that it applies to each cylinder. **EPA should clarify that it applies only to each cylinder as follows: "[t]he volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) for each compressor cylinder."**

AXPC also supports American Petroleum Institute's (API) comment that that reciprocating and centrifugal compressors should be subject to a work practice standard and not an emission limit for

the reasons stated by API.[81] Under a work practice standard, the operator would screen the compressor to determine the volumetric leak rate from each cylinder and replace the rod packing where the volumetric leak rate exceeds the applicable threshold. So long as the operator timely replaces rod packing, there is no deviation.

Additionally, AXPC proposes an alternative to conducting the annual inspection via Method 2D. **AXPC proposes, that in lieu of annual Method 2D test, an operator can utilize an OGI camera as a screening tool to scan the rod packing vent during the required fugitive emission surveys – *e.g.*, quarterly for compressor stations subject to NSPS OOOOb or EG OOOOc**. **Under this alternative, if the operator detects no emissions with an OGI camera during a routine fugitive emissions survey, no action is required because the volumetric flow rate from the compressor cylinder is assumed to be well below the proposed 2 scfm limit, given that OGI cameras are capable of detecting hydrocarbon emissions well below a 2 scfm flowrate. However, if the operator observes emissions with the OGI camera, the operator would confirm within 30 days that the emissions are below the 2 scfm limit via a high volume flow sampler using Method 2D.** AXPC believes this proposal is very conservative given that OGI cameras can detect emissions much lower than the proposed 2 scfm. AXPC believes this is a cost-effective alternative because it allows operators to take advantage of staff already onsite to conduct the fugitive emission survey, and the OGI camera can detect emissions well below the proposed threshold. Further, this approach may alleviate high volume flow sampler supply issues noted just below.

APXC supports EPA's exclusion of reciprocating compressor at well sites. Specifically, EPA's proposal makes clear that reciprocating compressors at a well site are not affected facilities. In Section II.L.i of these Comments, AXPC proposes to clarify the definition of centralized production facility.

Finally, AXPC proposes that operators be able to simply replace rod packing every 8,760 hours instead of conducting monitoring as currently proposed. High volume flow samplers have not been commercially available for long and while they are becoming more available, there is significant concern about being able to obtain those samplers timely and in sufficient quantity to comply with the rule.

II.K. <u>EPA should replace "root cause analysis" with "investigative analysis" throughout the final rule.</u>

EPA's Proposal requires that operators conduct a "root cause analysis" in response to receiving notification of a super-emitter emissions event[82] and following detection of emissions via an alternative screening technology.[83] EPA does not define the term "root cause analysis" which can take on many meanings. **AXPC proposes that EPA replace "root cause analysis" with "investigative analysis" throughout the final rule, both in NSPS OOOOb and EG OOOOc**.

We agree that EPA's investigative actions listed §§60.5371b(c) and .5388c(c) are appropriate and practicable as far an investigating and conducting initial corrective actions for super-emitter events. However, EPA's use of the term "root cause analysis" is problematic, as the term is vague and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs. It has a somewhat different meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make

[81] *See* API Supplemental Proposal Comments § 10.1.
[82] Proposed 40 C.F.R. §§ 60.5317b(c), .5388c(c).
[83] *Id.* §§ 60.5398b(4)(b)(C)(iv), .5398c(4)(b)(C)(iv).

it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when the super-emitter program is implemented. To address this concern, we recommend the actions EPA as outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §§60.5371b and .5388c.For similar reasons, AXPC proposes that EPA replace "root cause analysis" with "investigative analysis" in §§60.5398b and .5398c.

II.L. Definitions

II.L.i. Centralized Production Facility

EPA defines a "centralized production facility" in relevant part as "one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells." This definition is important because requirements may differ if an affected facility is located at a well site or a centralized production facility. For example, reciprocating compressors located at a well site are not affected facilities, while those located at centralized production facility are affected facilities. EPA's definition of a well site does not provide complete information for an operator to determine if a location is a well site or a centralized production facility. **AXPC requests that EPA clarify that a centralized production facility is a facility serving wells in which all wells are located off-site (*i.e.*, not on the same location as the centralized production facility).** EPA's discussion of centralized production facilities in the November 2021 Notice does not make clear why EPA chose to define a centralized production facility as one servicing any offsite well, rather than a centralized facility receiving liquids from exclusively offsite wells.

II.M. CEDRI Reporting Template

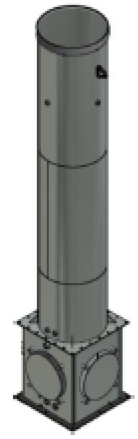
AXPC requests that EPA facilitate a robust and transparent stakeholder process to finalize the CEDRI reporting template for NSPS OOOOb as soon as practicable following publication of the final rule in the Federal Register. Operators rely on this template to inform recordkeeping and reporting processes, and operators cannot wait until close to the due date of the first annual report to have the final reporting template. Specifically, AXPC requests that EPA post the draft CEDRI reporting template to EPA's CEDRI website and solicit and incorporate comments on the template.

APPENDIX 1

Cimarron Energy Inc., Model: ECD-3-48HV-90 Design Capacity Flow Curve

*AXPC provides this design capacity flow curve for the purpose of demonstrating that combustion control device manufacturers rate a control device's design capacity relative to pressure. In providing this document, AXPC's intent is not to provide an endorsement or recommendation of the use of this control device or other control devices sold by the manufacturer.

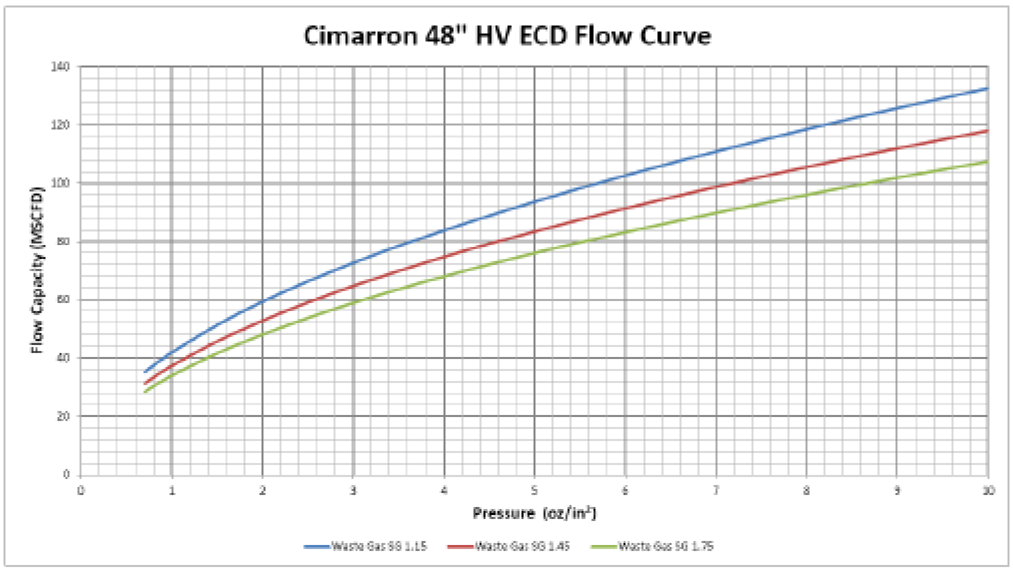
Model: ECD-3-48HV-90



Operational Design

Lower Operating Pressure: 1 oz/in^2
Upper Operating Pressure: 10 oz/in^2
TVOC Destruction Efficiency: >98% DRE when operating within pressure range

Calculated Flow Capacity Curve



Mechanical Design

Overall Dimensions:	56" Square Base x 303" Height
Weight:	Approx. 4,380 pounds (excludes Concrete Pad)
Burner:	90 Orifices (F-90)
Stack:	Insulated
Stack Internal Operating Temperature:	800 – 2000°F
Design Structure Wind Loading:	90 mph 3sec Wind Gust per ASCE 7-05
Ambient Temperature:	-20 to 120 °F
Electrical Area Classification:	Non-hazardous