Comments on U.S. Environmental Protection Agency's Proposed Rule Addressing Oil and Natural Gas Sector: Emission Standards for New and Modified Sources

80 Fed. Reg. 56,593 (Sept. 18, 2015)

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Table of Contents

INTRODUCTION

The Texas Oil & Gas Association (TXOGA) submits the following comments on EPA's *Oil and Natural Gas Sector: Emission Standards for New and Modified Sources; Proposed Rule,* 80 Fed. Reg. 56,593 (Sept. 18, 2015) (Proposed Rule).

Founded in 1919, TXOGA is the largest and oldest petroleum organization in Texas, representing more than 5,000 members. The membership of TXOGA accounts for over 90 percent of all crude oil and natural gas produced in Texas and is responsible for a preponderance of the State's refining capacity. TXOGA member companies produce a quarter of the nation's oil, a third of its natural gas and account for one-fourth of the U.S. refining capacity.

TXOGA first became involved in the rulemakings related to upstream and midstream oil and gas production in 2012 when EPA finalized Subpart OOOO's requirements and TXOGA petitioned for judicial review and also for reconsideration. Throughout the rulemakings that followed to implement the requested reconsideration, TXOGA endeavored to provide meaningful technical, policy, and legal input to EPA's process. We hope to provide similarly helpful information to EPA in this rulemaking process and appreciate the number of issues on which EPA has solicited comment. Because of the breadth of the issues being addressed by the proposal, and as discussed in our October 26, 2015, request for a comment period extension, TXOGA believes that longer than 75 days is necessary to provide an opportunity for complete input on the proposed regulations. We urge EPA to reopen the comment period to allow for additional input on the proposal.

OVERVIEW OF COMMENTS

TXOGA highlights the following key points from our detailed comments:

- EPA should withdraw its proposal for several reasons, including:

  - That it failed to make an endangerment finding and significant contribution finding for methane and for methane from this source category;
  - The flaws in the cost/benefit analysis. As discussed in detail below, there are several critical inadequacies and omissions in the Agency's cost/benefit analysis that must be corrected.

- If EPA nonetheless proceeds:

  - It is critical to clarify and adopt appropriate regulatory provisions so that it is apparent that methane will not cause a source to become subject to PSD or Title V permitting solely by virtue of its methane emissions and to ensure that methane is not subject to a PSD significance level of zero. Even though EPA should have made a separate endangerment finding and significant contribution finding for methane and for methane from this source category, the issue of permitting still must be clarified.

- The rule should provide options for crediting corporate and state/local LDAR programs as alternative compliance approaches. Owners and operators have made substantial investments in highly effective LDAR programs, which perform as well as or better than would be required under the proposed rule. Allowing these programs to be used to demonstrate compliance or act as an off-ramp is consistent with Clean Air Act mandates as well as numerous prior rulemaking actions in which EPA sought to avoid duplication of requirements and streamline regulatory implementation.

- There should be a one-year phase-in of compliance and the time frame for conducting initial surveys and commencing LDAR should be 180 days after the date production begins or the date a modification begins operations. The proposed rule does not take into account the many practical circumstances under which the start of production may be delayed or ramped up, or a well site temporarily shut in, all of which would result in an inaccurate emission profile under the proposed 30-day requirement. Moreover, as proposed, facilities ramping up production will be required to complete expensive, and more importantly, duplicative surveys.

- The "next gen" compliance options discussed in the preamble should not be adopted. These options would be extremely expensive and the associated costs have not been considered in the cost-benefit analysis for this proposal.

- The digital photography option should be rejected. In addition to posing a security risk and even First Amendment concerns, digital photographs are not the most effective means for assuring compliance and instead will prove to be an unnecessarily costly and burdensome requirement.

- Reporting of "quantitative environmental results" on corporate websites should not be required because EPA is without authority to issue such a requirement. Moreover, requiring companies to include compliance information on their web sites is unnecessarily duplicative and overly burdensome.

- The definition of well site needs to be revised to eliminate non-contiguous centralized tank batteries and should be modeled on 40 C.F.R. Part 63, Subpart HH. As proposed, the definition is overly broad and potentially conflicts with the agency's source determination proposal.

- The definition of modification needs to be narrowed to be more consistent with the statutory definition of modification. The definition should also be revised to exclude refracturing of a well to maintain production, as refracturing does not necessarily result in an increase in emissions and fugitive emissions are determined using emission factors based on component numbers and the type of service, not pressure or volume flow rates of the fluids within those components.

An affected facility exemption should be included for pneumatic pumps emitting less than the 53 mscf/yr allowed for a low bleed pneumatic controller because most pneumatic pumps emit less than EPA allows for a low bleed pneumatic controller.

DETAILED COMMENTS*

I. EPA Should Clarify That the Regulatory Actions in This New Source Performance Standard Related to Methane Do Not Trigger Prevention of Significant Deterioration (PSD) and Title V Permitting Applicability and That the Tailoring Rule Significance Levels for Greenhouse Gases (GHGs) as a Group Apply to Methane.[1]

It is TXOGA's understanding that EPA does not intend for the direct regulation of methane under NSPS to:

(1) cause sources that would be "major" for methane alone to be considered major stationary sources under the PSD program or major sources under the Title V permitting program;

(2) cause sources that are already major stationary sources for purposes of PSD program to require a PSD permit if a modification causes emissions of only methane to increase by the significance level; or

(3) require a new significance level to be set solely for methane.

Unfortunately, the preamble language and regulatory language do not make these intended results explicit,[2] and they must, as the regulation of methane in this rule has the potential for implications not only for the oil and gas sector but also for all industrial operations.

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* TXOGA's indication of support for any particular concept (e.g., agreeing with EPA that it is better to target gross emitters in the fugitive emissions monitoring program) should not be interpreted as indicating TXOGA support for this rulemaking or in any way waiving arguments to challenge this rulemaking as a threshold matter in court.

[1] TXOGA notes that EPA is required to make an endangerment and significant contribution finding for methane and for this source category's emissions of methane before proceeding with this regulatory action. TXOGA adopts the comments of other oil industry trade associations on this issue and nothing in this document should be interpreted as waiving that argument.

[2] EPA states in the preamble:

> In this action, the EPA is proposing to further regulate VOC emissions as well as proposing performance standards for methane emissions from this industry. With respect to the latter, the EPA identifies the air pollutant that it proposes to regulate as the pollutant GHGs (which consist of the six wellmixed gases, consistent with other actions the EPA has taken under the CAA), although only methane will be reduced directly by the proposed standards.

80 Fed. Reg. at 56,600-01 (emphasis added).

A. This Regulatory Action Does Not (and Cannot) Cause Otherwise Minor Sources to Become Major Sources for Purposes of PSD and Title V Based on Methane Emissions or to Cause Existing Major Sources to Trigger PSD Modification Provisions Based Solely on Methane Emissions.

As indicated above, because the proposed preamble and regulatory language (or other docketed materials) do not speak comprehensively to the implications of the direct regulation of methane, it appears that the Agency believes its regulation of methane in the NSPS will not result in methane triggering PSD or Title V permitting requirements. TXOGA agrees that regulation of methane under the NSPS should not cause sources that would otherwise be minor sources for purposes of PSD and Title V to become major sources or that otherwise major sources could trigger PSD solely because of a physical or operational change that increases methane emissions.

In *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (*UARG*), the U.S. Supreme Court rejected EPA's interpretation of the Clean Air Act (CAA or the Act) that would have caused GHGs on their own to cause a source to be subject to PSD and Title V permitting.[3] The Court further found that EPA's authority did not extend to rewriting statutory provisions that were clear on their face as to the major source levels, even if well motivated as an attempt to account for the ubiquitous nature of GHG emissions compared with pollutants that traditionally have been regulated under PSD and Title V.

Whether or not EPA uses this rulemaking to establish a permissible statutory interpretation as to why GHGs do not *on their own* cause a source to trigger PSD or Title V permitting, it is important for EPA to make clear to states and regulated entities that EPA's action of directly regulating methane does not mean that methane on its own can cause a source to be considered major for PSD and Title V purposes or that a PSD major modification can be caused solely due to an increase in methane emissions following a physical operational change.

Even though EPA should have made a separate endangerment finding for methane and a significant contribution finding for methane from this source category, the issue of permitting still must be clarified. EPA could clarify that methane should be treated as part of the group of GHGs by adopting an approach similar to the one it took in the CAA Section 111(b) rulemaking for carbon dioxide emissions from Electric Generating Units (EGUs).[4] There, EPA added a regulatory provision clarifying that the pollutant regulated is GHGs, which was simply taking the

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[3] The Court recognized the "'fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.'" 134 S. Ct. at 2441 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000)). In doing so, the Court stated: "In sum, <u>there is no insuperable textual barrier to EPA's interpreting 'any air pollutant' in the permitting triggers of PSD and Title V to encompass only pollutants emitted in quantities that enable them to be sensibly regulated at the statutory thresholds, and to exclude those atypical pollutants that, like greenhouse gases, are emitted in such vast quantities that their inclusion would radically transform those programs and render them unworkable as written</u>." *Id.* at 2442 (emphasis added).

[4] *See* EPA, *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule*, 80 Fed. Reg. 64,510 (Oct. 23, 2015).

form of a limit on carbon dioxide.[5] As explained in footnote 2, above, EPA has already stated as much in the preamble to this proposed rule. Specifically, EPA should adopt the following language in any final rule:

> **Which pollutants are regulated by this subpart?**
>
> (a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane.
>
> (b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).
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> (2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions,[6] the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.
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> (3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.
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> (4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

We note that such action is appropriate here because treating methane as a "triggering" pollutant would be inconsistent with congressional intent, bringing into the PSD and Title V programs numerous sources that Congress never contemplated as sufficiently large to justify the regulatory burdens associated with these major source programs.[7] The U.S. Court of Appeals for

[5] *See* 40 C.F.R. § 60.5515.

[6] We note that in the regulations for EGUs, EPA added the phrase "for affected facilities" at this point. We note that it is more clear to exclude this phrase since EPA is trying to clarify PSD applicability for all facilities.

[7] The Supreme Court limited its decision in *UARG* as follows: "Finally, the Solicitor General suggests that the incompatibility of greenhouse gases with the PSD program and Title V results chiefly from the inclusion of carbon dioxide in the 'aggregate pollutant' defined by EPA. We decide these cases on the basis of the pollutant 'greenhouse gases' as EPA has defined and regulated it, and we express no view on how our analysis might change were EPA to define it differently." 134 S. Ct. at 2444 n.7. This language from the Supreme Court decision makes it all the more important EPA to state clearly that issuance of these regulations does not mean that methane can serve as the sole

the District of Columbia Circuit (D.C. Circuit) has "clearly discern[ed]" Congress's vision for PSD permitting.[8] "Congress was concerned with large industrial enterprises."[9] Obviously, smaller sources like oil and gas well sites do not fit within this category.

To the extent EPA takes the position that methane can trigger PSD directly as a result of this rulemaking, the Agency cannot do so until it articulates a statutory interpretation that reconciles the group of GHG emissions and CO_2 specifically not triggering PSD but allows methane to do so. As TXOGA suggested in an amicus brief in the *UARG* case, the view that only National Ambient Air Quality Standards (NAAQS) pollutants could trigger PSD, recognizing that locally impacting air pollutants were the focus of the PSD program, could be a basis for excluding these emissions from PSD triggering activities.

A preferred solution would be to remove methane from the proposed rule and maintain the "natural gas as a surrogate for VOC" concept in the 2012 NSPS. Indeed, EPA admits that regulating methane will not result in additional methane reductions.[10] Should EPA determine that regulation of VOC alone is sufficient to achieve the desired VOC and methane reductions, EPA can avoid the PSD and Title V implications by revising the rule accordingly.

In any event, it is critical for EPA to be clear about the implications of this rulemaking and to take whatever steps are necessary to ensure that methane does not trigger PSD or Title V permitting directly.

B. To the Extent EPA Proceeds with Issuance of this NSPS, the Significance Threshold for GHGs as a Group Should Apply to Methane for Anyway Sources.

As written, the Tailoring Rule applies to GHGs in the aggregate and does not speak to whether an individual GHG, such as methane, may be evaluated under the proposed rule. Importantly, EPA also has not established a significant emissions level for methane alone. As discussed above, EPA needs to clarify that the carbon dioxide equivalent ($CO_{2\text{-}e}$) significance threshold is applicable to methane when regulated on its own (*e.g.*, by making the clarification noted in subsection A, above). It is incumbent upon EPA to include a provision in the final Subpart OOOOa rule that explicitly states that the Tailoring Rule applies to avoid unnecessary confusion and uncertainty.

For purposes of determining whether an increase in emissions resulting from a physical or operational change triggers PSD permitting, 40 C.F.R. § 52.21(b)(23)(i) defines what

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basis for a source to trigger PSD or Title V permitting (*i.e.*, methane could only be subject to PSD in the case of an "anyway" source).

[8] *Ala. Power Co. v. EPA*, 636 F.2d 323, 353 (D.C. Cir. 1980).

[9] *Id.* at 354.

[10] *See* EPA, *Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector* at 1-1 (Aug. 2015) ("In addition, we are proposing methane standards for certain emission sources that are currently regulated for VOC (*i.e.,* hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). However, we do not expect any incremental benefits or costs as a result from regulating methane for currently regulated VOC sources.")).

constitutes the "significant" emissions level for specific pollutants. For pollutants that EPA has regulated in the past, it has established a significance level, *e.g.*, 100 tons per year (tpy) for carbon monoxide (CO), 40 tpy for nitrogen oxides (NO_X), 10 tpy for hydrogen sulfide (H_2S). For those pollutants *not listed* in 40 C.F.R. § 52.21(b)(23)(i), 40 C.F.R. § 52.21(b)(23(ii) defines what constitutes a "significant" emissions level: "Significant means, in reference to a net emissions increase or the potential of a source to emit a regulated NSR pollutant that paragraph (b)(23)(i) of this section, does not list, any emissions rate." (emphasis added).

Under 40 C.F.R. § 52.21(b)(49)(i), EPA defined the significant emissions level for GHGs defined as the aggregate group of six[11]:

> *Greenhouse gases* (GHGs), the air pollutant defined in §86.1818-12(a) of this chapter as the aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, shall not be subject to regulation except as provided in paragraphs (b)(49)(iv) through (v) of this section and shall not be subject to regulation if the stationary source maintains its total source-wide emissions below the GHG PAL level, meets the requirements in paragraphs (aa)(1) through (15) of this section, and complies with the PAL permit containing the GHG PAL.

This significant emissions level is defined as follows:

> The term emissions increase as used in paragraphs (b)(49)(iv) through (v) of this section shall mean that both a significant emissions increase (as calculated using the procedures in paragraph (a)(2)(iv) of this section) and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section) occur. For the pollutant GHGs, an emissions increase shall be based on tpy $CO_{2\text{-}e}$, and shall be calculated assuming the pollutant GHGs is a regulated NSR pollutant, and 'significant' is defined as 75,000 tpy $CO_{2\text{-}e}$ instead of applying the value in paragraph (b)(23)(ii) of this section.[12]

To the extent EPA takes the position that PSD will apply to the direct regulation of methane in this regulatory action, it is important that EPA make clear the Tailoring Rule's existing provisions apply to methane as part of the group of GHGs and that methane does not require its own significance level in order to avoid having a zero significance level.

In sum, EPA needs to be explicit that finalization of this proposed rule will not lead to triggering of PSD or Title V except for "anyway sources." This is easily accomplished, as EPA has shown by the language it included in the CAA Section 111(b) rule for EGU CO_2 emissions. Moreover, sound policy and basic principles of government administration dictate that this issue be addressed before EPA issues any final rulemaking.

[11] For purposes of defining GHGs, 40 C.F.R. § 86.1818-12(a) states: "This section contains standards and other regulations applicable to the emission of the air pollutant defined as the aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride."

[12] 40 C.F.R. § 52.21(b)(49)(iii) (emphasis added).

II. EPA Should Revise Its Approach to the Extent Necessary to Ensure that It Will Not Be Forced to Issue Existing Source Standards Under Section 111(d) of the Act.

EPA has indicated that even though it is proposing "new" source standards for methane under CAA Section 111(b), it does not intend to proceed with existing source standards under Section 111(d) at this time.[13] Instead, EPA proposes to exercise its discretion to refrain from promulgating a rule under CAA Section 111(d) for the time being to allow operators to work through voluntary measures to reduce existing sources of methane emissions, which would potentially eliminate the need to regulate methane under CAA Section 111(d).[14] TXOGA supports the concept of using voluntary measures to support a conclusion not only that there is no need for regulation of existing sources but also of new sources. We note that EPA could actually promote voluntary reductions by indicating its view in any final rule (or in advance of a final rule) that voluntary programs can be relied upon to avoid regulation under CAA Section 111(d).

Section 111 of the Act addresses pollutants on a source category-wide basis. Under CAA Section 111(b), EPA lists source categories which in the judgment of the Administrator "causes or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare," and then establishes "standards of performance" for the new sources in the listed category.[15] For existing sources in a listed source category, CAA Section 111(d) sets out procedures for the establishment of federally enforceable 'emission standards' of any pollutant not otherwise controlled under the CAA's State Implementation Plan (SIP) provisions or CAA Section 112. CAA Section 111(d)(1) provides:

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. . . . . .[16]

On July 23, 2015, EPA released a framework under which EPA can partner with oil and gas companies to undertake commitments to reduce methane emissions on a voluntary basis.[17] EPA projects that this framework "has the capability to comprehensively and transparently

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[13] See, *EPA Defends Discretion On Methane Rules For Existing Oil & Gas Sources,* Inside EPA/Climate, Climate Daily News (Jan. 26, 2015).
[14] *Id*.
[15] 42 U.S.C. § 7411(b).
[16] 42 U.S.C. § 7411(d)(1).
[17] *See* EPA, *Natural Gas STAR Methane Challenge: Proposed Framework* (Jul. 23, 2015) (*Methane Challenge*), *available at* http://www3.epa.gov/gasstar/documents/methane_challenge_proposal_072315.pdf.

reduce emissions and realize significant voluntary reductions in a quick, flexible, cost-effective way."[18] On this basis, EPA officials propose to use voluntary measures and the guidelines under Section 182 to address emissions from existing sources in lieu of promulgating a rulemaking under CAA Section 111(d).[19] The *Methane Challenge* will be just one of the measures available to companies to address existing sources.

Thus, although EPA has declined to address it presently, future administrations may be tasked with issuing CAA Section 111(d) standards for existing oil and gas sources if the Section 111(b) standards are finalized.[20]

To be sure, there is no deadline specified for promulgation of emission guidelines under Section 111(d) and EPA has explained the significant degree of discretion it has in establishing the guidelines when issued. Nonetheless, given the uncertainty in both the benefits and costs (discussed below), the lack of an endangerment and significant contribution finding as to methane emissions from the oil and gas sector (which we believe is required as a legal prerequisite to regulating methane emissions from this source category), and the profound implications for numerous small oil and gas source operators (many of whom are TXOGA members), we urge EPA to defer issuance of the Section 111(b) standards at this time.

III. The Proposed Rule's Benefit and Cost Estimates are Highly Uncertain and Conflict With the Administration's Guidelines on Estimating Benefits and Costs; EPA Cannot Rely on These Estimates in Making a Reasoned Decision Under Section 111.

Every aspect of EPA's assessment of the benefits and costs of the proposed rule is based on highly uncertain inputs and assumptions that render the final benefit and cost estimates unreliable and meaningless for decision-making. Key uncertainties are detailed below.

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[18] EPA, *Natural Gas STAR Methane Challenge Program Proposal*, http://www3.epa.gov/gasstar/methanechallenge/ (last visited Dec. 2, 2015).

[19] TXOGA is concerned with EPA's statements in the context of the Clean Power Plan regarding its interpretation of CAA Section 111(d), specifically:

> In a separate, concurrent action, the EPA is also finalizing a CAA section 111(b) rulemaking that regulates CO_2 emissions from new, modified, and reconstructed EGUs. The promulgation of these standards provides the prerequisite predicate for applicability of CAA section 111(d). <u>CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating "any existing source" of certain pollutants "to which a standard of performance would apply if such existing source were a new source</u>."

EPA, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Final Rule*, 80 Fed. Reg. 64,662, 64,715 (Oct. 23, 2015) (emphasis added).

[20] TXOGA notes that these comments should not be interpreted to mean that EPA is compelled to issue a Section 111(d) regulation. Rather, we are highlighting EPA's position as expressed in prior regulatory actions, and we note that the position is being litigated at this time in response to those actions. TXOGA's comment is that to the extent EPA believes a CAA Section 111(d) action is necessary, it should exercise its discretion to defer issuing such regulation and credit voluntary actions.

A. The Benefit and Cost Estimates are Based on Highly Uncertain Projections of the Number of Fractured and Re-fractured Oil Well Completions, Well Pads, Pneumatic Pumps, Compressors and Pneumatic Controllers that Will be in Place in 2020 and 2025.

1. The Projections are Based on Outdated Information Included in the U.S. Energy Information Agency's *2014 Annual Energy Outlook.*

Projecting the number of facilities in 2020 and 2025 that would be expected to change their emissions control activities as a result of this Proposed Rule is highly uncertain and will depend on market conditions. For instance, recent press reports indicate that the number of U.S. oil-drilling rigs – a proxy for drilling activity in the oil industry – has fallen by over 60 percent since October 2014.[21] This drastic reduction, however, is not considered in the Agency's analysis of benefits and costs. As EPA states in its draft *Regulatory Impact Analysis*, the Agency's estimates of the number of new and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the U.S. Energy Information Administration's (EIA's) *2014 Annual Energy Outlook.*[22] Reliance on these outdated projections severely undermines the validity of the resulting benefit and cost estimates for the Proposed Rule. The recent changes in market conditions are likely to have enduring impacts that could significantly alter production strategies and the likely number of affected facilities in the future even if energy prices recover.

2. The Number of Facilities Impacted in 2020 and 2025 Will Vary Significantly Based on Oil and Gas Prices, Technology Development and Changes in Federal and State Policies.

Even if EPA had relied on updated information regarding current trends in oil and gas well production, projecting the number of future affected facilities is highly uncertain. In addition to fluctuating market conditions, the number of affected facilities could vary significantly based on technology developments. The dramatic increases in U.S. oil production from 2009 to 2014 reflect technology innovation and the rapid adoption of new drilling approaches on private lands. The resulting technology improvements unlocked oil from areas that were previously considered out of reach by most drillers less than a decade ago. Very few analysts predicted the significance of the technology change and the consequence of its rapid adoption in the U.S. Technology changes will continue to affect future production in unpredictable ways that may alter the number of affected facilities and the production process. EPA's analysis fails to account for these significant uncertainties.

Similarly, EPA has also not considered the potential impact of changes in federal and state policies affecting access to public and private resources. Policy changes at the federal, state and local level may have profound impacts on the number of affected facilities in 2020 and 2025.

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[21] Dulaney, Chelsey, *U.S. Oil-Rig Count Rises After 10 Weeks of Declines*, Wall Street Journal, Nov. 13, 2015, *available at* http://www.wsj.com/articles/u-s-oil-rig-count-rises-after-10-weeks-of-declines-1447438840

[22] EPA, *Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector*, at 3-9 (Aug. 2015) (RIA).

For instance, EPA's recent decision to revise the ozone NAAQS[23] will result in a significant near-term increase in the number of nonattainment areas and potentially more stringent nonattainment regulatory classifications for existing nonattainment areas. Both outcomes could affect the projected number of affected facilities. Yet, according to the draft RIA, these impacts were not considered in developing the projections because the RIA control strategies for implementing NAAQS are "merely illustrative".[24] Moreover, the background TSD supporting this Proposed Rule states that the number of "controlled" completions and recompletions was estimated based on existing state regulations.[25] Because local ordinances were not included, EPA concludes that the calculated percentage of wells subject to state regulation should be considered a "conservative estimate."[26]

B. While EPA Correctly Notes the Significant Changes in the *2015 Annual Energy Outlook,* EPA Incorrectly Assumes that the Costs Per Facility and Broader U.S. Energy Market Impacts Would Remain the Same.

While EPA alludes to the significant differences between EIA's 2014 and 2015 *Annual Energy Outlook*[27], the Agency makes the unsupportable simplifying assumption that these changes will not affect the costs per facility. Long-term reductions in energy prices, however, will have a clear impact on costs by reducing the offsetting value of the recovered product. This will have a very direct and important impact in raising the overall cost of the rule for affected entities. In light of recent market developments, EPA's failure to conduct even a sensitivity analysis of the impact of a lower price environment on costs is unsupportable.

In addition, EPA has also failed to evaluate the fuller impact of this rule on U.S. energy production in a long-term lower-energy price environment. Lower prices will mean smaller profit margins that will be increasingly sensitive to changes in cost structure. The increased cost of complying with this rule may make more production assets uneconomical in a low-margin, competitive environment. By failing to fully analyze this scenario, EPA is underestimating the potential impact of this rulemaking on U.S. energy production.

C. The Benefit and Cost Analysis is Also Based on Equally Uncertain Estimates of the Before and After-Control Emission Rates From These Sources.

As EPA states in its draft RIA, the Agency's estimates of national emission reductions for the industry are derived by simply multiplying the unit-level emission reductions associated with each applicable control and facility type by the number of affected sources.[28] This approach, while transparent, underscores the deficiencies with the Agency's estimating techniques. Not only is EPA making unsupportable projections with regard to the number of

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[23] *See* EPA, *National Ambient Air Quality Standards for Ozone; Final Rule*, 80 Fed. Reg. 65,292 (Oct. 26, 2015).
[24] RIA, at 4-4 n.25.
[25] EPA, *Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities: Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa* at 20-21 (Aug. 2015) (Background TSD), EPA-HQ-OAR-2010-0505-5120.
[26] *Id.*
[27] RIA, at 3-9.
[28] *Id*. at 3-11.

affected facilities that will be in production in the U.S. in 2020 and 2025, the Agency is also making equally uncertain assumptions regarding their pre- and post-control emission levels.

1. EPA Admits a Critical Lack of Information on the Number of Leaks at Uncontrolled Facilities.

In estimating baseline emission levels, the background TSD and the draft CTG guidelines both rely on outdated information on the percent of components that are leaking. In both of these documents, EPA assumed a 1.18 percent leak rate for natural gas.[29] The importance of this very uncertain assumption is highlighted in footnote 53 of the background TSD which states that EPA generally lacked information on the number of leaks at uncontrolled facilities:

> There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant.[30]

Issuing regulations without a clear understanding of the magnitude of the problem underscores the weak basis and the premature nature of the Agency's decision to regulate.

2. More Recent Data Show That the Actual Number of Leaks At Uncontrolled Facilities is Likely to be an Order of Magnitude Lower Than EPA Estimates.

As noted above, EPA's assumed leak rate of 1.18 percent is based on a 2011 memorandum from an EPA contractor. An evaluation of the memorandum in turn shows that the leak rate assumption is based in part on a 1995 "Protocol for Equipment Leak Emission Estimates," confirming that the Agency is basing its analysis on outdated information.[31]

Recent data collected by TXOGA members show that the frequency of leaks is likely to be an order of magnitude lower than what EPA assumed in its regulatory analysis. Data collected directly in areas subject to State regulation show leak rates that range from 0.05 to 0.20 percent – with an average leak rate that is an order of magnitude lower than the 1.18 percent used by EPA in this Proposed Rule. The significance of this finding cannot be understated. It demonstrates that EPA is basing its assessment of the need for a regulatory program and its proposed control options on inadequate data that incorrectly exaggerate the need and value of regulation. A more accurate assessment of baseline emissions may well show that the proposed regulatory control options are highly cost-ineffective and should be abandoned or severely revamped.

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[29] Background TSD at 71 n.53; EPA, *Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft)* at 9-19 (Aug. 2015).

[30] Background TSD at 71 n.53 (citing Uniform Standards Mem. from Cindy Hancy, RTI Int'l, to Jodi Howard, EPA/OAQPS, *Analysis of Emission Reduction Techniques for Equipment Leaks*, (Dec. 21, 2011), EPA-HQ-OAR-2002-0037-0180) (Uniform Standards Memorandum).

[31] Uniform Standards Memorandum at 31, Attach. 2.

The uncertainty surrounding EPA's unit-level emission factors is highlighted by EPA's decision to convene a "Stakeholder Workshop on EPA GHG Data on Petroleum and Natural Gas Systems" in November 2015[32], a few days before the extended comment period closes. Many stakeholder presentations focus on core questions surrounding the unit level emissions from production compressors and well pads in different production basins as well as the uncertainties in the emission estimation assumptions and planned improvements. The workshop underscores the Agency's need to improve the underlying emission estimates and basis for its proposed regulatory decision. The scheduling of this workshop after the release of the Proposed Rule confirms that the Agency has prematurely and erroneously reached conclusions about the need, benefit, and cost of regulation before acquiring the necessary information.

D. EPA's Analysis Also Fails to Address the Regulatory Conflicts and Expected "Double Counting" of Reduced Emissions From the Department of Interior's Upcoming Rule to Address Venting, Flaring, and Leaks From Wells on Federal Lands.

The Office of Management and Budget (OMB) is currently reviewing an U.S. Department of the Interior (DOI) draft proposed rule to reduce venting, flaring, and leaks of natural gas from onshore wells located on federal and Indian leases. According to the Administration's Unified Agenda, the proposed rule will be released December 2015 and finalized by June 2016, roughly the same time period as this Proposed Rule.[33]

EPA's failure to address DOI's upcoming regulation confirms that EPA is inaccurately portraying the benefits and costs of the Proposed Rule by failing to adequately account for past regulations as well as ongoing regulatory actions that may reduce the need for new regulations.

E. EPA's Monetized Benefit Estimates Rely on a Flawed Social Cost of Methane (SC-CH_4) Estimate at Odds With the Administration's Guidance on Benefit-Cost Analysis.

EPA's estimates of the potential benefits of the Proposed Rule are based entirely on the Administration's recently developed estimate of the SC-CH_4.[34] According to the draft RIA, the SC-CH_4 estimates the monetary value of the global impacts associated with a marginal change in methane emissions in a given year. The SC-CH_4 estimate was first developed by two researchers in EPA's National Center for Environment Economics (NCEE) in 2011[35] and later refined in a 2014 paper[36] using modeling assumptions that are consistent with the Administration's social

[32] Information on EPA's workshop can be found at:
http://www3.epa.gov/climatechange/ghgemissions/Nov2015Workshop.html.

[33] *See* OMB, Reginfo.gov *available at*
http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201510&RIN=1004-AE14.

[34] RIA, at 1-6.

[35] The 2011 working paper was later published in *Energy Policy* in 2012.

[36] 80 Fed. Reg. at 56,654-56 (citing Alex L. Marten, Elizabeth A. Kopits, Charles W. Griffiths, Stephen C. Newbold & Ann Wolverton, *Incremental CH4 and N2O mitigation benefits consistent with the US Government's SC-CO2 estimates*, 15 *Climate Policy* 272-298 (2014, online publication; 2015, print publication) (Marten *et al*.)).

cost of carbon (SCC).[37] However, compared to the Administration's SCC value of $48 per ton for carbon dioxide in 2025 (using a 3 percent discount), EPA estimates that SC-CH_4 in 2025 will be $1,500 per ton (using a 3 percent discount rate) due to the fact that methane is believed to be 28 to 36 times more potent than CO_2.[38] The higher value per ton for SC-CH_4 magnifies the central concerns raised with the Administration's original SCC estimates and underscores their inappropriate application in this rulemaking.

1. EPA's Estimate of the SC-CH_4 Contains Many of the Same Flaws as the SCC.

Because the Administration's SC-CH_4 is based on the same integrated assessment models (IAMs) and assumptions as the SCC estimates, it shares the same fundamental weaknesses that render it unsuitable for regulatory analysis and decision-making. As noted in recent Congressional testimony, the IAMs are too sensitive to the modeler's assumptions to be legitimate tools for regulatory policy. In particular, relatively small changes in key inputs, such as the discount rate, time horizon for the analysis, and assumptions regarding climate sensitivities, can produce significant swings in the overall SCC estimates.

2. Contrary to Administration Guidance, EPA Incorrectly Provides Only a Global Estimate of SC-CH_4.

OMB Circular A-4 is clear in instructing agencies to provide estimates of the costs and benefits to U.S. citizens; benefits beyond the U.S. should be reported separately:

> Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.[39]

OMB's position on this important issue is clear. The requirement to present domestic estimates of the costs and benefits – those that accrue to citizens and residents of the U.S. – ensures symmetry in the cost and benefit estimates such that domestic cost estimates can be compared against domestic benefit estimates. By failing to include an estimate of the domestic-only benefits, the draft RIA only allows for an inappropriate and misleading comparison of potential domestic costs with global benefits.

Presenting a domestic-only estimate would reduce the benefit estimates for this Proposed Rule by more than 75 percent. According to a recent paper by economists Ted Gayer and Kip Viscusi, based on one integrated assessment model that permitted a U.S.-only analysis, the U.S.

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[37] "Specifically, the estimation approach employed by Marten *et al.* used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates (2.5, 3 and 5 percent), and aggregation approach used by the IWG to develop the SC-CO2 estimates." 80 Fed. Reg. at 56,655.

[38] *See* Marten et al. at Table 4-3 listing Martin's SC-CH_4 estimates using a 5, 3, and 2.5 discount rate.

[39] *See* OMB Circular A-4, *Regulatory Analysis* at 15 (Sept. 17, 2003) *available at* https://www.whitehouse.gov/sites/default/files/omb/assets/regulatory_matters_pdf/a-4.pdf.

received only 7 to 10 percent of the estimated global benefit.[40] If one assumes that the domestic share of the benefits is proportional to the current U.S. share of global GDP, then the domestic benefit may represent 23 percent of the global benefit.[41] Employing either of these ratios to the estimated global benefits included in the draft RIA would result in cost estimates for this rulemaking that exceed the projected benefits.

3. Relying on a Global Benefit Estimate Conflicts With the History of Section 111 and the Act's Requirements in Addressing International Air Pollution.

The exclusive presentation and use of a global benefit estimate also conflicts with the statutory basis and historical implementation of CAA Section 111 to regulate domestic sources of air pollution that may impact local air quality and the public health of U.S. citizens.[42] To address international air pollution concerns, the Clean Air Act established separate and specific authorities under CAA Section 115 on "International Air Pollution".[43] Specifically, CAA Section 115 expressly provides the Administrator with the authority to address air pollution that may cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare in a *foreign* country.[44] Under CAA Section 115, however, the Administrator's authority is constrained by the need to first assure reciprocity.[45] Section 115 specifically states that the section shall apply "only to a foreign country which the Administrator determines has given the United States essentially the same rights with respect to the prevention or control of air pollution occurring in that country as is given that country by this section."[46] In presenting only a global benefit estimate and in relying on this estimate to make regulatory decisions, EPA circumvents the clear statutory requirement to show that other major emitting countries have also taken equivalent action to protect U.S. citizens.

4. EPA's Benefit-Cost Analysis Also Conflicts With OMB Guidance by Failing to Include Benefit Estimates that are Based on a 7 Percent Discount Rate.

In instructing agencies with regard to employing appropriate discount rates, OMB Circular A-4 on "Regulatory Analysis" refers to OMB's basic guidance on the use of the discount rates included in OMB Circular A-94[47]. Circulars A-4 and A-94 clearly instruct agencies to employ a real discount rate of 7 percent in its base case analysis:

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[40] Ted Gayer & W. Kip Viscusi, *Determining the Proper Scope of Climate Change Benefits*, Geo. Wash. Regulatory Studies Ctr., at 10 (June 3, 2014) *available at* can be found at https://regulatorystudies.columbian.gwu.edu/regulatory-costs-and-benefits.
[41] *Id.*
[42] *See* 42 U.S.C. § 7411(b).
[43] 42 U.S.C. § 7415.
[44] *Id*. at § 7415(a) (emphasis added).
[45] *Id*. at § 7415(c).
[46] *Id*.
[47] OMB Circular A-94, *Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Program* (Oct. 29, 1992) *available at* https://www.whitehouse.gov/sites/default/files/omb/assets/a94/a094.pdf.

> As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.[48]

OMB is also clear and convincing on the rationale for including this discount rate. The 7 percent discount rate presents an estimate of the average "before-tax" rate of return to private capital that must be dedicated to installing the pollution control equipment needed to comply with this rulemaking.[49] While the results from lower discount rates may also be included in the regulatory analysis, these results should supplement rather than replace a regulatory analysis that employs a 7 percent discount rate.

F. Many of the Uncertainties and Problems Raised by EPA's Benefit Analysis Could be Reduced by Relying on VOC a Surrogate for Methane.

Reliance on VOC as a surrogate for methane would prevent the unnecessary imposition of duplicative regulations on many sources, saving EPA and regulated entities significant resources. As EPA clearly states in the Executive Summary of the draft RIA, the Agency is proposing new methane standards for certain emission sources that are currently regulated for VOC (*i.e.*, hydraulically fractured gas well completions, equipment leaks at natural gas processing plants)."[50] However, the RIA further states that it does not expect "any incremental benefits or costs as a result from regulating methane for currently regulated VOC sources."[51] Why then is the EPA proposing new regulations for these numerous sources?

Proposing to impose additional methane regulations on already-regulated VOC sources despite its expectation of no incremental benefits or costs conflicts with Administration regulatory guidance. Executive Order No. 12866 instructs Agencies to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations".[52] More importantly, this same Executive Order instructs agencies to first "identify the problem it intends to address."[53] If EPA cannot find any additional benefits from further regulation, admittedly, there is no problem worthy of additional regulation.

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[48] OMB Circular A-4 at 33.
[49] *Id*.
[50] RIA, at 1-1.
[51] Draft RIA, at 1-1.
[52] Executive Order No. 12866, *Regulatory Planning and Review*, at § 1(b)(10) (Sept. 30, 1993), reprinted in 58 Fed. Reg. 51,735 (Oct. 4, 1993).
[53] *Id*. at § 1(b)(1).

G. The Cost Analysis to Support BSER Is Inadequate if EPA Adopts the Suggested "Next Generation" (Next-Gen) Compliance Options Described Conceptually in the Preamble.

EPA requests comment on a number of Next-Gen based options throughout the preamble. In particular, EPA identifies potential areas for third-party verification under this proposal, including (1) review and certification of the design of closed vent systems by third party professional engineers, including verification of the control system installation; and (2) an audit program for the collection of fugitive components at well sites and compressor stations.[54]

First, EPA solicits comment on establishing a third party verification program, which would require an independent third party to verify that the regulated entity is meeting specific compliance obligations.[55] The Agency identifies three key components of such a program: (1) the program would require verification of compliance monitoring and reporting; (2) third parties would be required to be accredited and to satisfy certain criteria to establish independence and competence; and (3) the program would require a mechanism to ensure regular and effective oversight of third-party reviewers by the EPA and/or states. The Agency acknowledges that it "is considering a broad range of possible design features for such a program under the following two scenarios: (A) Third-Party Verification of Closed Vent System Design and (B) Third-Party Verification of IR Camera Fugitives Monitoring Program."[56]

More specifically, EPA proposes to include a provision requiring review and certification of the design of closed vent systems by third party professional engineers, including verification of the control system installation. Alternatively, EPA suggests that a continuous pressure monitoring device or system be installed on thief hatches, pressure relief devices, and other bypasses from a closed vent system. The Agency indicates that these approaches could ensure adequate design and sizing of the closed vent system. Without evaluating the costs associated with such controls, EPA requests comment on the criteria by which a PE would be required to verify that the closed vent system is designed to accommodate streams routed to the control system and the types of cost-effective pressure monitoring systems that could be utilized under the alternative approach.

Second, EPA requests comment on the use of an audit program for the collection of fugitive emissions components at wells sites and compressor stations. The Agency explains, "we are anticipating a structure in which the facilities themselves are responsible for determining and documenting that their auditors are competent and independent pursuant to specified criteria."[57] EPA also seeks comment on whether auditors should be required to have accreditation from a recognized auditing body, EPA, or other potentially relevant consensus standards or protocols. The Agency identifies an array of stringent criteria that it declares will ensure independence and competence, including requiring "licensing as a Professional Engineer, knowledge with the requirements of the rule and the operation of monitoring equipment (e.g., optical gas imaging),

[54] *See* 80 Fed. Reg. at 56,648-49.
[55] 80 Fed. Reg. at 56,648.
[56] *Id.*
[57] *Id*. at 56,649.

experience with the facility type and processes being audited and the applicable recognized and generally accepted engineering practices, and training or certification in auditing techniques."[58] Moreover, EPA identifies an exacting set of criteria for establishing auditor independence, including that the auditor and its personnel must not perform any other work for the owner or operator within the 3 years before and after serving as an auditor; all personnel who participate in the audit must sign and date a conflict of interest statement; and owners or operators cannot provide future employment to any of the auditor's personnel who participated in the audit for a period of at least 3 years following the submittal of the final audit report.[59] While EPA acknowledges "[t]here may be other options, in addition to the approaches above, that may increase owner or operator flexibility," the Agency cites concerns over "risks of introducing bias into the program, resulting in less robust and effective audit reports."[60]

One certainty emerges from the Agency's discussion of next-gen options: The implementation of next generation approaches the Agency outlines in the proposal preamble would be extremely expensive, and mandatory nationwide requirements would cause an operational and economic disadvantage for operators and impairment to economic development. Nonetheless, EPA has failed to include these costs in its cost-benefit analysis for the rulemaking. Furthermore, EPA presumes, without support, that third-party audits will improve compliance. EPA cannot drop these costly and onerous requirements into the rule without additional opportunity for notice and comment regarding the associated costs and impacts.

H. Given the Significant Flaws in the Agency's Cost and Benefit Estimates, EPA Cannot Rely on These Estimates to Support a Final Rule and Doing So Would Constitute Both Arbitrary and Capricious Action and a Failure of Reasoned Decisionmaking.

Agency action will generally be found arbitrary and capricious by a reviewing court when the Agency has: (1) relied on factors that Congress did not intend it to consider; (2) failed to consider an important aspect of the issue at hand; or (3) offered an explanation for its decision that runs counter to the evidence before it.[61]

Moreover, the CAA incorporates the same reasoned-decisionmaking standard that serves as a pillar of the Administrative Procedure Act.[62] Under this standard, "[n]ot only must an

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[58] 80 Fed. Reg. at 56,649.

[59] 80 Fed. Reg. at 56,649-50.

[60] 80 Fed. Reg. at 56,650.

[61] *See Burlington Truck Lines Inc. v. United States*, 371 U.S. 156, 168 (1962). Furthermore, an agency may not reverse prior policy decisions without providing a reasoned explanation for the change. *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 514-15 (2009) (an agency changing its course by rescinding a rule is obligated to supply reasoned analysis for the change) (quoting *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 412 U.S. 800, 808 (1973); *see also Atchison, Topeka & Santa Fe Ry. Co. v. Wichita Bd. of Trade*, 412 U.S. 800, 808 (1973) (an agency must "explain its departure from prior norms"); *AT&T Corp. v. FCC*, 236 F.3d 729, 736-37 (D.C. Cir. 2001) (reasoned decision making standard requires explanation for departure from prior decision).

[62] *See, e.g.*, *Am. Farm Bureau Fed'n v. EPA*, 559 F.3d 512, 519-20 (D.C. Cir. 2009) (per curiam) (explaining that, even under the CAA, the Court must examine "the record to ensure the agency has considered the relevant factors and reasonably explained how it reached its conclusions").

Agency's decreed result be within the scope of its lawful authority, but the *process* by which it reaches that result must be logical and rational."[63] As a consequence, the D.C. Circuit has not hesitated to invalidate rules promulgated under the CAA that are "unsupported by adequately reasoned decisionmaking."[64]

The numerous problems with EPA's benefit and cost estimates render them highly misleading and meaningless as a tool for reasoned decision-making. The docketed analysis artificially inflates the overall benefits by consistently employing assumptions -- such as the exclusive use of lower discount rates and the equally exclusive reliance on a global estimate of benefits –to present an overall conclusion that the potential benefits of the proposed rule will exceed the costs. An analysis of these assumptions, however, quickly demonstrates that one can only reach this conclusion by ignoring current Administration policies with regard to benefit-cost analysis, as reflected in OMB Circulars A-4 and A-94, as well as CAA Section 111's statutory/regulatory history and the requirements for reciprocity under CAA Section 115 to address international pollution.

IV. Comments on Specific Aspects of the Proposed Regulations

In evaluating the various technology determinations that EPA proposes in this action, it is important to recognize the applicable statutory provisions, judicial precedents, and EPA rulemaking precedents under the NSPS. In Section A, below, we provide an overview of the best system of emission reduction (BSER) principles and we reference aspects of them for comments on particular BSER determinations as appropriate.

A. The "Best System of Emission Reduction" Controls the NSPS Analysis.

The NSPS program is one of the first technology requirements created under the CAA over 40 years ago. While statutory language has changed in certain respects over time, the interpretations of EPA and the courts continue to be relevant in determining the proper approach to the NSPS standard-setting analysis, and it is against this backdrop and fundamental principles that TXOGA has evaluated the proposal and offers comments. CAA Section 111(a)(1) defines the term "standard of performance" as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation <u>achievable</u> through the application of the <u>best system of emission reduction</u> which (<u>taking into account</u> the <u>cost</u> of achieving such reduction and any <u>non-air quality health and environmental impact and energy requirements</u>) the Administrator determines has been <u>adequately demonstrated</u>.[65]

[63] *Allentown Mack Sales & Serv., Inc. v. NLRB*, 522 U.S. 359, 374 (1998) (emphasis added).
[64] *Am. Farm Bureau Fed'n*, 559 F.3d at 515; *see also Chem. Mfrs. Ass'n v. EPA*, 217 F.3d 861, 866-67 (D.C. Cir. 2000) (invalidating a rule promulgated under the CAA because the EPA failed to engage in "reasoned decisionmaking").
[65] 42 U.S.C. § 7411(a)(1)(emphasis added).

Thus, EPA's determination of BSER, is critical to the establishment of CAA Section 111(b) standards that are consistent with statutory requirements. Courts have found that this determination occurs in a three-step process:[66] (1) EPA identifies a system/systems that has/have been "adequately demonstrated" for the affected sources in the category; (2) EPA determines the emission levels "achievable" using the adequately demonstrated system or systems; and then, finally, (3) EPA "exercise[s] its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations."[67] While any NSPS must be based on the performance of BSER with respect to the type of source to which the standard applies, individual new sources are not required to actually install or operate the particular technology or system identified as BSER, only to meet the numerical performance level established by the NSPS.[68]

Like the five-step analysis for determining best available control technology (BACT), EPA needs to separately analyze each of the three steps in the BSER analysis.

1. The Technology on Which the NSPS Is Based Must Be "Adequately Demonstrated."

The technology on which the NSPS is based must first be determined by EPA to be "adequately demonstrated". Case law explains that an adequately demonstrated system of emission reduction is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[69] D.C. Circuit cases also stand for the proposition that an "adequately demonstrated" system must have an operational history that shows more than mere technical feasibility for a source. There generally should be on-the-ground demonstrations.[70] Finally, to be adequately demonstrated, a technology must be available for all source types in the category. For example, in its 2005 proposed revisions to the NSPS for Subpart Da units, EPA rejected supercritical boiler design, integrated gasification combined cycle (IGCC) technology, and the use of clean fuels as potential bases for its revised standards due in part to the unavailability of these options across source types within the category.[71]

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[66] *See Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

[67] *Id.*

[68] CAA § 111(b)(5); *see also* EPA, *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act*, at 2 *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf ("EPA may not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.").

[69] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 (D.C. Cir. 1973).

[70] *Sierra Club*, 657 F.2d at 341 n.157 (dry scrubbers were not adequately demonstrated for the control of sulfur dioxide emissions from coal-firing EGUs where there was lack of implementation of the technology at full-scale facilities, an inability to adequately extrapolate from experience at prototype facilities, a lack of data for sources firing different types of coal, and unresolved issues regarding waste disposal from the scrubbers); *Essex Chem.*, 486 F.2d at 435 n.19, 438 (control techniques were not adequately demonstrated for certain sulfuric acid plants where the "dual absorption process" had never been shown to perform efficiently in those plants and because the byproducts presented "noteworthy disposal problems.").

[71] *See* 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005).

2. The Numerical Standards Must be "Achievable" Based on Use of the "Adequately Demonstrated" Technology.

After EPA determines which system is adequately demonstrated in step 1, it must determine what levels of emissions are achievable by individual sources applying the system in step 2. EPA then explains how the standard "is achievable under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur."[72] EPA must also show that the standards are achievable "for the industry as a whole," not merely some sources within the industry.[73]

To demonstrate achievability, EPA "(1) identif[ies] variable conditions that might contribute to the amount of expected emissions, and (2) establish[es] that the test data relied on by the Agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[74] Emission standards, therefore, cannot be based on narrowly extrapolated data from a subcategory of sources. Courts have rejected NSPS where EPA based them on data from a narrow set of sources that were not demonstrative of the entire range of sources subject to the standards.[75]

The D.C. Circuit has held that "EPA has a statutory duty to promulgate achievable standards."[76] Setting an achievable standard requires "approaching the task in a systematic manner that identifies relevant variables" that must be "taken [into] account" when analyzing the data.[77] If EPA has not created sufficient record evidence demonstrating that "significant variables relevant to the standard's achievability" were taken into account, the court may remand the rule.[78] The D.C. Circuit has stated that the "promulgation of standards based upon inadequate proof of achievability would defy the Administrative Procedures Act's [APA's] mandate against action that is 'arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.'"[79]

CAA Section 111 case law holds that NSPS must be capable of being met by all new sources within the source category. In *Sierra Club*, the court concluded that to be achievable, the test data supporting the final standards must be representative of the *entire industry*. The court stated that the Agency needs to "establish that the test data relied on by the Agency are representative of potential *industry-wide performance*, given the range of variables that affect achievability of the standard."[80] *National Lime* also supports the conclusion that CAA Section

[72] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46, 433 (D.C. Cir. 1980).
[73] *Id.* at 431.
[74] *Sierra Club*, 657 F.2d at 377 (citing *Nat'l Lime*, 627 F.2d at 433).
[75] *See, e.g., Nat'l Lime*, 627 F.2d at 432-33; *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d a375, 396, 402 (D.C. Cir. 1973).
[76] *Nat'l Lime,* 627 F.2d at 443.
[77] *Id.*
[78] *Id.* at 445-46.
[79] *Id.* at 430 (quoting 5 U.S.C. § 706 (1976)).
[80] *Sierra Club*, 657 F.2d at 377 (emphasis added).

111 standards need to be achievable by all types of sources in a regulated industry.[81] There, the court rejected a NSPS because "the record d[id] not support the 'achievability' of the promulgated standards *for the industry as a whole*."[82] It further noted that "EPA itself acknowledged in this case that standards of performance . . . must . . . [assure achievability of the standard for the industry as a whole] for *all variations of operating conditions being considered* anywhere in the country."[83]

The D.C. Circuit reached the same conclusion that standards must be achievable for the industry as a whole in *Portland Cement Association v. EPA*. There, petitioners argued that EPA failed to consider the impact of NSPS standards on portland cement kilns of older design that, if modified, could become subject to CAA Section 111 standards.[84] The court concluded that petitioners' arguments failed "because contrary to [their] contention, EPA demonstrated how all regulated kilns could meet [the] standards. EPA based its PM and sulfur dioxide limits 'on control technologies that can be applied to *any* kiln type and achieve the same control levels that would be expected with a new kiln at similar costs.'"[85]

3. BSER Requires Consideration of Environmental, Energy, and Economic Concerns.

Step 3 of the BSER analysis requires EPA to select a standard within that range of achievable levels using the adequately demonstrated technology that "represents *the best balance of economic, environmental, and energy considerations*."[86] At this juncture, EPA may also consider the amount of emission reductions and technologies that "promise significant cost, energy, non air health and environmental benefits." These factors are to be considered at the plant level as well as "at the national and regional levels and over time."[87] In weighing these considerations, standards that "give a competitive advantage to one State over another in attracting industry" are not permissible.[88]

The courts have held that the cost of a given NSPS must be reasonable: "to be 'adequately demonstrated,' the system must be 'reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without being exorbitantly costly in an economic or environmental way.'"[89] In *National Lime*, the court remanded a NSPS in part because "there [was] no evidence in the record that the 'costs' of adjusting for . . . routine variations [in conditions] (assuming such adjustments be possible) were considered by the Agency in promulgating its standard."[90]

[81] *See Nat'l Lime*, 627 F.2d at 431.
[82] *Id*. at 431 (emphasis added).
[83] *See*, *id*. at 433 (citation omitted) (emphasis added).
[84] *Id*. at 190.
[85] *Id*. (quoting 75 Fed. Reg. 54,970, 54,995-96 (Sept. 9, 2010) (emphasis in original)).
[86] *Sierra Club,* 657 F.2d at 330.
[87] *Id.* at 330, 346.
[88] *Id.* at 325.
[89] 79 Fed. Reg. 1430, 1464 (Jan. 8, 2014) (quoting *Essex Chem.*, 486 F.2d at 433).
[90] *Nat'l Lime*, 627 F.2d at 431, n.46.

B. EPA Should Issue A Supplemental Proposal in Order to Fulfill the Agency's Statutory Obligation to Provide an Adequate Opportunity for Notice and Comment.

In the Next Generation Compliance section of the preamble to the Proposed Rule EPA proposes or solicits comment on "establishing a third-party verification program," which would involve regulated entities hiring auditors and certifiers with particular qualifications in order to proceed with construction or otherwise satisfy requirements of this rule.[91] Indeed, EPA acknowledges the Agency "is considering a broad range of possible design features for such a program" under two general scenarios: third-party verification of closed vent system design and third-party verification of the IR camera fugitives monitoring program.[92] However, the proposed rule does not contain any substantive provisions that would reflect this programmatic approach to verifying compliance.[93] While there are some situations in which new regulatory language is appropriately introduced in a final rule, in this instance, EPA proposes to add an entirely new third-party compliance *program* in the final rule without taking comment on the regulatory provisions. While it is always appropriate to solicit comment on the concepts of a planned regulatory program, doing so does not substitute for soliciting comment on the regulatory provisions that would implement those concepts. As a result, members of the public would be deprived of a meaningful opportunity to comment on any third-party program should EPA decide to issue such requirements in final form.

With respect to the concept of third party verification in the context of the proposed NSPS, TXOGA has several overarching concerns related to this concept that are not raised in the proposal: First, the proposal is silent as to what substantive criteria the industry must satisfy to comply with the regulation. Second, the proposal does not specify the verification procedures for compliance, if any. Third, the substantive criteria needs to be geared to what is truly necessary to demonstrate compliance to achieve the BSER as codified. The proposal does not outline the criteria to establish that a regulated entity has implemented BSER. These criteria will necessarily be geared toward that particular technology or limitation. In many instances in the proposal, there is no necessary follow up verification except for the standard initial verifications in quarterly or semi-annual reports in typical NSPS.

Moreover, to go beyond the requirements EPA has proposed and fully analyzed in the proposal, EPA must justify why additional procedures are necessary for compliance verification, *i.e.*, why the current certification requirements are insufficient, particularly given the increased costs of compliance with any new verification provisions. These costs must be taken into account in the establishment of the BSER standard in the first place. These additional costs should be taken into account when determining if the cost of the standard is reasonable.

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[91] 80 Fed. Reg. at 56,648-50.
[92] *Id.* at 56,648.
[93] EPA includes a provision verification that optical gas imaging (OGI) equipment meets the required specifications in Section 60.5397a(c)(7)(i), but provides that verification may be performed by the facility, by the manufacturer, <u>or</u> by a third-party. Proposed 40 C.F.R. § 60.5397a(c)(7)(i), 80 Fed. Reg. at 56,668.

The CAA incorporates the Administrative Procedure Act notice requirements by reference and expressly requires EPA to provide notice of its proposed rule through a statement of its basis and purpose, including (a) the factual data on which the proposal is based, (b) the methodology used in obtaining and analyzing data, and (c) the major legal interpretations and policy considerations underlying the proposed rule.[94] Such notice is required in order to give the public a meaningful opportunity to comment.[95] "The significance of rulemaking cannot be underemphasized. It gives parties affected by a decision an opportunity to participate in the decision-making process and forces EPA to articulate the bases for its decisions."[96] EPA should provide adequate notice and opportunity for comment on the details of any provisions that involve regulated entities hiring third parties, particularly given that the details of the regulatory provisions will have a significant impact on the costs of such a program.

C. Fugitive Emissions From Well Sites and Compressor Stations

1. The Affected Facility Definition is Overly Broad and Exceeds EPA's Authority under Section 111 of the Act.

EPA proposes to regulate the collection of "fugitive emissions components" at a "well site."[97] The provisions of Part 60 apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility."[98] "Affected facility" is defined broadly to mean, with reference to a stationary source,[99] "any apparatus to which a standard is applicable."[100] EPA explains that "under the proposed standards, the affected facility would be 'the collection of fugitive emissions components at a well site'"[101] and defines "well site" as:

> one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids,

[94] 42 U.S.C. § 7607(d)(3); *see also* 5 U.S.C. § 553(b)(3), incorporated by reference in 42 U.S.C. § 7607(d)(3) (requiring notice of "either the terms or substance of the proposed rule or a description of the subjects and issues involved"); 5 U.S.C. § 553(c) (requiring agency to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments …").

[95] 42 U.S.C. § 7607(d)(4), (5).

[96] *Donner Hanna Coke Corp. v. Costle*, 464 F. Supp. 1295, 1305 (W.D.N.Y. 1979) (citation omitted); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding "[t]hat EPA allowed petitions for reconsideration is not an adequate substitute for an opportunity for notice and comment prior to promulgation") (citation omitted).

[97] 80 Fed. Reg. at 56,611.

[98] 40 C.F.R. § 60.1(a).

[99] Stationary source includes "any building, structure, facility, or installation which emits or may emit any air pollutant." *Id.* § 60.2.

[100] *Id.*

[101] 80 Fed. Reg. at 56,611.

or produced water from wells not located at the well site (e.g., centralized tank batteries).[102]

Given the above, TXOGA believes that the proposed well site definition is both ambiguous and overly broad, in addition to being unworkable. Indeed, the definition exceeds the authority granted under CAA Section 111 to establish emission standards for new or modified "stationary sources." Accordingly, EPA should narrow, simplify, and clarify the definition to conform to the commonly understood meaning of the term and to be consistent with the meaning of "stationary source" under Section 111 of the Act and the relevant NSPS and permitting regulations. Moreover this definition directly conflicts with the agency's source determination proposal, which includes a geographical restriction on sources for the purposes of aggregation. Indeed, EPA is arguably adopting an approach here that is akin to option 2 in the source determination proposal – the option that it says is not preferred. As discussed below, EPA should be following the well-considered approach under Part 63, Subpart HH.

Specifically, the proposed definition of "well site" is ambiguous and overbroad in that it encompasses not only one or more wells, but also "production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad." As a consequence, the proposed rule envisions a "stationary source" that could encompass a broad and geographically dispersed system of wells and centralized batteries or natural gas treating and processing facilities, whether or not connected by pipeline, provided the collection of sites receives production from such wells. This approach could bring in emission units that are located large distances from the well site and for that reason, is simply unworkable. Moreover, the phrase "one or more areas that are directly disturbed during drilling" introduces significant ambiguity and does not appear to serve any regulatory purpose. It is unclear what the import of "one or more areas" is in the context of a well site, and the reference to drilling activities, which are not regulated or within the scope of EPA's authority since they are not emitting activities, creates additional uncertainty regarding the scope of this definition.

Measured against the statutory and regulatory definitions that have long defined the scope of NSPS requirements, the proposed well site definition fails. It is inconsistent with the statute's definition of "stationary source"—which is "any building, structure, facility, or installation" emitting an NSPS regulated pollutant.[103] It is also inconsistent with how EPA has implemented Part 60. In Section 60.1, the NSPS rules provide that the provisions of this part apply to an "owner or operator of any stationary source *which contains an affected facility*."[104] Section 60.2 defines the a*ffected facility* to mean, "with reference *to a stationary source*, any apparatus to which a standard is applicable."[105]

Under the statute's definition, *affected facility* cannot be defined more broadly than what could be designated as a single stationary source. This makes sense because Section 60.1(c) ties the stationary source definition to Title V, which limits the major source (which is comprised of

[102] *Id.* at 56,612, 56,697.
[103] 42 U.S.C. § 7411(a)(3).
[104] 40 C.F.R. § 60.1(a) (emphasis added).
[105] 40 C.F.R. § 60.2 (emphasis added).

stationary sources) to those sources on contiguous or adjacent property.[106] Specifically, Section 60.1(c) provides that in addition to complying with Part 60, an "owner or operator of an affected facility may be required to obtain" a Title V operating permit.[107] This language establishes the tie between Part 60 and Title V's definition, since a source that could not be aggregated for purposes of Title V, clearly cannot be brought into Part 60. In *Summit Petroleum Corp. v. EPA*, the Court rejected EPA's attempt to aggregate physically independent but "interrelated" natural gas sweetening plant and various sour gas production wells commonly owned but separately located within an area of approximately forty-three square miles.[108] The Court held that "EPA's determination that the physical requirement of adjacency can be established through mere functional relatedness is unreasonable and contrary to the plain meaning of the term 'adjacent.'"[109]

The definition of well-site is also inconsistent with the principles established by Congress in Section 112(n) of the Act, which EPA has implemented in 40 C.F.R. Part 63. In CAA Section 112(n)(4), Congress provided:

> (4) Oil and gas wells; pipeline facilities.-
>
> (A) Notwithstanding the provisions of subsection (a) of this section, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.
>
> (B) The Administrator shall not list oil and gas production wells (with its associated equipment) as an area source category under subsection (c) of this section, except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from

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[106] 42 U.S.C. § 7661(2) ("The term 'major source' means any stationary source (or any group of stationary sources located within a contiguous area and under common control) . . . ."); *see also* 40 C.F.R. § 71.2 ("Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group . . . .").
[107] 40 C.F.R. § 60.1(c).
[108] 690 F.3d 733 (6th Cir. 2012).
[109] *Id.* at 735.

> such wells present more than a negligible risk of adverse effects to public health.[110]

Under this provision, Congress recognized the unique nature of oil and gas wells and pipeline facilities and sought to prevent in appropriate aggregation of these units. Moreover, Congress directly tied the Section 112 definition to Section 111 providing that the term "stationary source" is to "have the same meaning" as that term has under Section 111 in Section 112(a)(3)[111] and directing EPA to make its list of categories for Section 112 regulation "consistent" with the Section 111 list of source categories to the extent practicable in Section 112(c)(1).[112] Thus, any approach in Section 111 must take into account Congress' direction on the stationary source definition in Section 112 for these operations.

Implementing these mandates, EPA adopted a series of definitions in 40 C.F.R. Part 63. Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities. "Facility" is defined in Section 63.761 as:

> any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment *that is located within the boundaries of an individual surface site as defined in this section*. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. *Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility*. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.[113]

Section 63.761 defines "surface site" as "any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed."[114]

> The EPA developed the proposed definition of facility to (1) identify criteria that define a grouping of emission points that meet the intent of the language

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[110] 42 U.S.C. §7412(n)(4).
[111] 42 U.S.C. § 7412(a)(3).
[112] 42 U.S.C. § 7412(c)(3).
[113] 40 C.F.R. § 63.761 (emphasis added).
[114] *Id*.

> contained in section 112(a)(1) of the Act: ''* * * located within a contiguous area and under common control, * * *''; and (2) contain terms that are meaningful and easily understood within the regulated industries. . . . Finally, the terms contained in the definition of facility (e.g., surface site and lease) are well understood within the industry and by enforcement agencies . . . .[115]

In addition to the other problems with the definition, the proposed well-site definition is not consistent with the well understood meaning of the term. Based on the above, EPA should correct these shortcomings by defining "well site" (solely for purposes of this regulation)[116] to mean a crude oil and natural gas production facility (defined in § 63.761) that contains one or more wells within the boundaries of an individual surface site as defined in this section. Such an approach would define the affected facility in terms that are meaningful and commonly understood and in a manner consistent with the statutory definition of "stationary source" ("any building, structure, facility, or installation which emits or may emit any air pollutant").[117] It would also align with the definition of "facility" in the NESHAP standard for the oil and gas source category in Part 63 Subpart HH.

2. The Definitions of "Modification" for Purposes of Existing Well Sites and Compressor Stations Should be Revised to be Consistent with Equipment Leak Provisions in Other NSPS and to Account for Refracturing a Well Site to Maintain Production.

EPA proposes to regulate fugitive emissions following "modification" of existing well sites and compressor stations and includes a new definition of "modification" specific to the provisions setting fugitive emissions standards at well sites and compressor stations and for this purpose only.[118] EPA states that it intends for "such provisions in the specific subparts [to] supersede any conflicting provisions in § 60.14 of the General Provisions."[119] Specifically, EPA offers the following definitions of "modification" for well sites and compressor stations:

> For purposes of § 60.5397a, a "modification" to a well site occurs when:
>
> (i) A new well is drilled at an existing well site;
>
> (ii) A well at an existing well site is hydraulically fractured; or
>
> (iii) A well at an existing well site is hydraulically refractured.[120]

[115] 64 Fed. Reg. 32,610, 32,618 (Jun. 17, 1999) (emphasis added).
[116] We add this qualifier in recognition of the fact that there are other instances where "well site" is defined and that EPA's adoption of this rule should not implicate other regulatory regimes – which may involve other authorities – or set a precedent for other regulatory programs that may exist in the future.
[117] 40 C.F.R. § 60.2.
[118] 80 Fed. Reg. at 56,614.
[119] *Id.*
[120] Proposed 40 C.F.R. § 60.5365a (i)(3), 80 Fed. Reg. at 56,664.

> For purposes of § 60.5397a, a "modification" to a compressor station occurs when:
>
> > (1) A new compressor is constructed at an existing compressor station; or
> >
> > (2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.[121]

EPA identifies two instances in which it believes emissions increases would occur at well sites and compressor stations. First, with respect to well sites, EPA presumes that "[w]hen a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well."[122] Second, with respect to compressor stations, EPA postulates that "fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to an existing compressor, would result in an increase in emissions to the fugitive emissions components."[123]

EPA has defined the term "modification" in the NSPS regulations as:

> any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[124]

While it is true that EPA can provide for deviations from the general modification definition in a particular subpart, it does not follow that EPA can define a modification more broadly than the statutory provisions would allow. The definition of modification in CAA Section 111(a)(4) limits "modifications" to changes that result in an increase in the amount of an air pollutant emitted or which result in the emission of an air pollutant not previously emitted.[125] Thus, in order to consider the proposed listed activities automatically to be a modification, EPA must establish that those activities will by definition cause an emissions increase (as defined in the NSPS regulations) or emission of a new pollutant.

The analysis in the proposal does not establish the requisite increase. A fundamental requirement of rulemaking is that an agency properly support and explain its factual

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121 Proposed 40 C.F.R. § 60.5365a(j), 80 Fed. Reg. at 56,664-65.
122 80 Fed. Reg. at 56,614.
123 *Id.*
124 40 C.F.R. § 60.2 (definition of modification).
125 42 U.S.C. § 7411(a)(4).

conclusions.[126] It is well established that in rulemaking, an "agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[127] Here, EPA bases its cost analysis and proposed standards for fugitive emissions from well sites and compressor stations on fugitive emissions factors from Publication AP-42.[128] Those AP-42 emission factors are based on the number of components in service and not on the pressure or volume flow of the fluids within those components.

Refracturing a well does not categorically mean that emissions will increase. Indeed, EPA should revise the definition of "modification" for well sites to *exclude* refracturing of a well. Since fugitive emissions are determined using emission factors that are based on the number of each component and the service (gas, heavy oil, light oil and water/oil) and not on the pressure or volume flow rate of the fluid contained within those components, the proposal's factual conclusion that increasing pressure increases emissions from the affected facility is incorrect.

Moreover, refracturing a well, which is subsurface work, does not necessarily result in the addition of "fugitive emission components" (*i.e.*, in that adding fugitive components could increase emissions). Subsurface physical activity should not affect surface fugitive emissions unless there is an accompanying surface activity that would cause an increase in emissions. A physical change in, or change in the method of operation of, an existing well's surface equipment does not necessarily occur as a consequence of refracturing. In addition, refracturing may only maintain the production rate at a well, which would not increase the production rate beyond existing equipment capacity. Thus, refracturing should not be considered a "modification."

This conclusion is further supported by the General Provisions for Part 60, which exclude from the definition of modification an "increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility."[129] Since refracturing does not require a capital expenditure, it should not be considered a "modification."

With respect to compressors and compressor stations, fugitive emissions from the collection of fugitive emissions components at a station are a function of the number of such components, not compression capacity. Any change to a compressor that does not result in a net addition of fugitive emissions components should not be a modification because no increase in emissions would occur.

Finally, EPA's rationale for its proposed "modification" provisions for fugitive emissions components at well sites and compressor stations is inconsistent with equipment leak provisions in other NSPS, including Subpart OOOO. Specifically, Subpart OOOO and the proposed

[126] *See Gen. Chem. Corp. v. United States*, 817 F.2d 844, 846 (D.C. Cir. 1987) (per curiam) (finding agency action arbitrary and capricious where agency analysis was "inadequately explained").
[127] *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).
[128] 80 Fed. Reg. at 56,635, 56,639 (citing EPA, *Protocol for Equipment Leak Emission Estimates*, Table 2-4, (Nov. 1995) (EPA–453/R–95–017).
[129] 40 C.F.R. § 60.14(e)(2).

Subpart OOOOa regulate the group of all equipment, except compressors, within a process unit within a natural gas processing plant. Under proposed Section 60.5365a(f)(1), the "[a]ddition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart."[130] Capital expenditure is defined in proposed Section 60.5430a.[131] The addition of some new equipment (valves, flanges, connectors, etc.) does not necessarily result in NSPS applicability for a gas plant. EPA did not include similar language for its proposed fugitive emissions standards for well sites and compressor stations. EPA's component-based approach in the proposal conflicts with the group-based approach in the gas plant provisions. A similar provision should apply to well sites and compressor stations. EPA should provide the option to owner/operator that if a piece of process equipment is added, specifically, a dehydrator unit, process heater, storage vessel, or separator, that would be considered a modification, unless the source owner or operator showed that a capital expenditure was not required.

To the extent that EPA nonetheless proceeds on the path of the proposed rule, and without conceding that such an approach is supportable under applicable statutes or regulations, TXOGA believes that the term compression capacity needs to be defined in the proposal if it is to be used to establish applicability. EPA also requests comment on (1) "whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well" and (2) "whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor."[132] On the first question, only those components connected to the fractured, refractured, or added well should be subject to the fugitive requirements. On the second question, the requirements should only apply to the fugitive sources connected to the added compressor. In addition, EPA has to ensure that it does not sweep in distant sources from the well-site notwithstanding the definition potentially encompassing distant equipment (which we do not believe is authorized).[133]

3. The Proposed Definition of "Fugitive Emissions Component" Needs to be Revised Because It Is Overbroad and Ambiguous.

The proposal would regulate the collection of all "fugitive emission components" at a well site or at a compressor station. Under proposed Section 60.5430a, a "fugitive emissions component" would be defined as:

> *any* component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator

[130] Proposed 40 C.F.R. § 60.5365a(f)(1), 80 Fed. Reg. at 56,664.
[131] Proposed 40 C.F.R. § 60.5430a, 80 Fed. Reg. at 56694.
[132] 80 Fed. Reg. at 56,638, 56,643.
[133] Note that TXOGA is responding to these questions in light of EPA's definition of well site and notes that its responses would differ if TXOGA's definition is accepted by EPA.

> seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.[134]

As written, the proposed definition (1) unreasonably and unnecessarily overlaps with other provisions, and (2) is overly inclusive in that the definition erroneously includes a number of components that should be removed. The result of this broad definition is to bring within the ambit of the NSPS as many components as possible. This renders the definition overly burdensome and arbitrary in that it ultimately impedes the purpose and utility of the proposal.

In general, thief hatches should not be included in the definition of fugitive emission component. By design and function, thief hatches are routinely opened to allow access to the tank for gauging. These are not "fugitive" emissions in the common sense notion of that term. In addition, spring-loaded thief hatches function as pressure/vacuum vents to prevent an over- or under-pressure condition in the tank to prevent a catastrophic release. Again, such hatches are designed to vent as part of *normal operations*. The proposed definition of fugitive emission component provides "[d]evices that vent as part of normal operations, . . . are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission."[135] Storage vessel affected facilities using a control device or routing emissions to a process have closed vent systems, thief hatches, or other openings on a storage vessel separately regulated by Subpart OOOOa and subject to periodic inspections. Pneumatic pumps and compressors are other affected facilities that may have closed vent systems separately regulated. Proposed Section 60.5411a(c)(2) provides, "[y]ou must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections."[136] Proposed Section 60.5416a(c)(1) requires monthly inspections of each closed vent system "for defects that could result in air emissions."[137] For covers, Section 60.5416a(c)(2) also requires monthly inspections "for defects that could result in air emissions."[138] Absent a justification for including these components in the definition of "fugitive emissions component," the definition is overly burdensome. A further issue is that there are not emission factors available for these types of sources. The proposed definition should therefore be revised to remove closed vent systems, thief hatches or other openings on a storage vessel.

It is also unnecessary to include separators, pressure vessels, dehydrators, or heaters, since they would already be included to the extent they are equipped with valves, flanges and

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[134] Proposed 40 C.F.R. § 60.5430a, 80 Fed. Reg. at 56,695 (emphasis added).
[135] *Id*.
[136] Proposed 40 C.F.R. § 60.5411a(c)(2), 80 Fed. Reg. at 56,676.
[137] Proposed 40 C.F.R. § 60.5416a(c)(1), 80 Fed. Reg. at 56,685.
[138] *Id*. at § 60.5416a(c)(2).

connectors, and other components. This equipment should be removed from the definition to eliminate redundancy. Furthermore, crankcase vents should also be removed from the definition of "fugitive emissions component," as such equipment "vents as part of normal operations." To otherwise include crankcase vents in the definition would cause it to become unworkable. In addition, while it makes sense for the definition of "fugitive emissions component" to include each pump, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in crude oil, hydrocarbon condensate or natural gas service, it should not include compressors, which are separately regulated. Fugitive emission component should therefore exclude certain equipment, including equipment in vacuum service, double block and bleed valves, lab sample analyzer vents and distance pieces.

Finally, the rule should also explicitly limit "fugitive emissions component" to those components in natural gas (including fuel gas), crude oil, or hydrocarbon condensate service to ensure that EPA limits the scope of the rule to the source category being regulated. Equipment leak components that are not in produced hydrocarbon service, such as those in methanol, glycol or other oilfield chemical or distillate fuel service, cannot be subject to OGI or Method 21 inspections. Such liquids "have the potential to emit VOC," but have a low vapor pressure and are not significant sources of fugitive emissions.

EPA should revise its proposed Section 5430a definition of "fugitive emissions component" as follows:

> Fugitive emissions component means ~~any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including~~ each pump, pressure relief device, open-ended valve or line, valve, or flange or other connector that is in natural gas (including fuel gas), crude oil, or hydrocarbon condensate service. ~~but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

Since the affected facilities at well sites and compressor stations includes the "collection of all fugitive emissions components," the recommended definition would suffice.

EPA might also address the concerns above by revising the "equipment" definition, which is proposed to be:

> Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of methane and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.[139]

TXOGA is open to other solutions, provided that they do not bring into fugitive monitoring components that are not appropriately included in the rule.

4. Any Fugitive Emissions Monitoring Program Should be Limited to "Gross Emitters."

EPA acknowledges that a broad fugitive emissions monitoring program could prove problematic in terms of implementation and cost and specifically solicited comment on whether the program should be limited to "gross emitters":

> Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to "gross emitters.[140]

TXOGA agrees with EPA that the fugitive emissions program should be limited to "gross emitters." A broad fugitive emissions monitoring program will be extremely costly and yield limited environmental benefit and does not represent the "best balance of economic, environmental, and energy considerations" required under the BSER analysis.[141] EPA is also correct that a small number of components, specifically compressors and flashing tanks, are responsible for the majority of fugitive leaks.

EPA should provide for a Directed Inspection and Maintenance (DI&M) program in lieu of a Leak Detection and Repair (LDAR) program as an efficient and cost effective means of mitigating leaks from gross emitters. The DI&M approach, which has long been voluntarily applied by industry and is well documented through EPA's Natural Gas STAR program, differs from LDAR in that the DI&M program approach efficiently and effectively facilitates identification of components that are the highest emitters. By contrast, LDAR requires leak

[139] Proposed 40 C.F.R. § 5430a (definition of equipment).
[140] 80 Fed. Reg. at 56,637 n. 105.
[141] *Sierra Club v. Costle*, 657 F.2d at 330; *see also* 42 U.S.C. § 7411(a)(1) ("standard of performance" is defined as the degree of emission limitation achievable through the application of the BSER "taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements").

detection surveys of each individual component—a less efficient approach to target gross emitters.

An effective DI&M approach could include screening a site containing equipment that previous experience indicates has a higher probability of leaking with OGI from the site perimeter, not more than 100 feet from fugitive emissions components; identification of components observed by OGI to be leaking ("fugitive emissions"); repair of component or components within 30 days of discovery; and verification of repair with OGI or soap bubbles within 30 days following repair.[142]

Accordingly, TXOGA supports limiting the fugitive emissions program to "gross emitters."

5. TXOGA Supports the Concept on Which EPA Solicits Comment Regarding Providing an Alternative Compliance Approach for Sources Complying with State or Corporate LDAR Programs.

EPA correctly solicits comment on criteria the agency can use to determine whether corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions for purposes of establishing "alternative methods of compliance or otherwise provid[ing] appropriate regulatory streamlining."[143] TXOGA supports the rationale behind the agency's request for comment and recommends that EPA include an alternative compliance mechanism in the final rule.

Alternative compliance will be a critical component of the final rule. As EPA recognizes, many owners and operators have already implemented state and corporate-wide fugitive emissions reduction programs. These programs have evolved based on either state regulatory requirements or programs that companies have developed as responsible corporate citizens to use innovative and often cutting-edge approaches to reduce leaks. Furthermore, corporate programs often better target and detect leaks based on owner or operator experience and, at the same time, achieve the same ends EPA seeks without the complex and administratively burdensome compliance program set forth in the EPA's proposal. EPA should encourage corporate programs that achieve the leak performance aims of the NSPS in recognition of the fact that companies that have implemented programs across their facilities have made substantial investments well in advance of any regulatory requirements and that it will be extremely problematic to suddenly shift gears and implement a different program. Thus, companies with systems for tracking inspections should be allowed to continue to utilize them, and make them available to inspectors as requested, instead of developing entirely new systems. Like the proposal, these systems would also track site location, date, and number of leaks, so the leak rate aims of the NSPS will be met.

An alternative compliance option would allow owners and operators to advance existing LDAR programs, focusing energy and resources on emission reductions. Moreover, owners and

[142] We also note that Method 21 can also be an alternative screening method and should be allowed.
[143] 80 Fed. Reg. at 56,596.

operators are more likely to adopt LDAR programs in advance of the compliance date – assuming EPA appropriately adopts the one-year compliance extension TXOGA recommends in Section IV(C(8)(A), *infra* – if there is an opportunity to streamline requirements and ease the administrative burden of compliance. And, by allowing these sound programs to continue, EPA will ensure that companies that are applying them to both new and existing sources (which is typical) will continue to implement such programs for existing sources.[144]

There are at least three potential options for supporting an alternative compliance approach under the terms of the Clean Air Act. TXOGA requests that EPA to include all of these options in the final rule. As EPA acknowledges in the preamble, the programs that pre-dated EPA's proposed regulation evolved based on either state regulatory requirements or programs that companies have developed as responsible corporate citizens to use innovative and often cutting-edge approaches to reduce leaks.

There is considerable precedent for inclusion of alternative compliance mechanisms in EPA rules. For example, in some instances, EPA has adopted as an "alternative standard" for similar state or local rules.[145] In other instances, EPA has adopted an "alternative means of emission limitation" that allows sources or even equipment manufacturers to apply for an equivalency—based on emissions—for an alternate standard.[146] In other instances, EPA has created a regulatory "off-ramp" for sources that implement pollution control requirements that would be required by a rule and allow them to document the controls, but not be subject to burdensome recordkeeping and reporting requirements.[147] Still in other cases, EPA has allowed compliance with other federal rules to satisfy a particular rule's obligations in order to avoid duplicative reporting and recordkeeping regimes.[148]

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[144] Here again, we note that the same concept should apply to state and corporate programs that cover other aspects of this proposed rule including, for example, RECs, pneumatic controllers, and pneumatic pumps.

[145] 40 C.F.R. § 60.103a(g) ("An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section.").

[146] 40 C.F.R. § 60.103a(j) ("Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section."); 40 C.F.R. § 60.114a ("If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112a, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement."); 40 C.F.R. §60.114b (same); 40 C.F.R. § 60.634 (same); 40 C.F.R. § 60.694 (same); 40 C.F.R. § 60.746 (same); 40 C.F.R. § 60.5402 (same); 40 C.F.R. § 60.480(e).

[147] 40 C.F.R. § 60.5365(h)(1) (providing that gas wells that undergo a green completion following refracturing are not considered modified and therefore are not affected facilities under the NSPS).

[148] 40 C.F.R. § 60.480(e) (As an alternative means of compliance, "[o]wners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482 through 60.487 for an affected facility."); 40 C.F.R. 480a(e) (same); 40 C.F.R. § 60.110a(c) (same); 40 C.F.R. § 60.110b(e) (same); 40 C.F.R. § 60.560(j) (same). Note that this compilation of examples is not comprehensive and merely represents a sampling of the many alternative compliance options provided in the regulations.

As it stands, the proposal will disproportionately increase the costs of compliance for those owners and operators that have already implemented fugitive emissions programs. Consequently, TXOGA urges EPA adopt the following alternative compliance options, which are consistent with EPA's stated intent to continue to encourage corporate-wide voluntary efforts to achieve emissions reductions and streamline regulatory compliance. There are at least three ways the agency could rely on these programs as a compliance alternative:

- Include an alternative standard relying on state and voluntary programs per CAA Section 111(h)(1).
- Provide for alternative compliance relying on state and voluntary programs per Section 111(h)(3).
- Create applicability criteria relying on requirements per Section 111(h)(1).

a. EPA Should Include an Alternative Standard Relying on State and Voluntary Programs Per CAA Section 111(h)(1) or an Alternative Compliance Option Under the Rule.

Under the first approach, EPA would include a provision in the final rule that designates an alternative standard of performance under CAA Section 111(h)(1), which allows EPA to prescribe a performance standard that reflects the best technological system of continuous emission reduction if it is "not feasible to prescribe or enforce a standard of performance."[149] In addition, EPA can avoid the inefficiencies associated with overlapping state programs by incorporating these programs by reference into the final rule, designating them as satisfactory alternatives to compliance with the federal program.

EPA did this, for example, in Subpart Ja, Standards of Performance for Petroleum Refineries with respect to Bay Area Air Quality Management District flare minimization. Specifically, Section 60.103a(g) provides:

> An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to [EPA].[150]

[149] 42 U.S.C. § 7411(h)(1).
[150] 40 C.F.R. § 60.103a(g).

Any fugitive emission monitoring program required by rule, whether or not approved as part of a SIP, that is legally and practically enforceable by a state or local administrative authority should be considered equivalent.

Alternatively, EPA could consider periodic publication of a list of state or local rules, permits by rule, general permits or other permits or programs that would be approved as an alternative to meeting fugitive emissions standards for well sites and compressor stations. EPA already has such a program where it lists combustion control devices that have been tested under §60.5413(d).

TXOGA also supports a provision that allows an owner or operator to elect to voluntarily comply with a state program at all affected facilities if subject to the state regulations at other facilities. This provision would streamline the compliance process for regulated entities and avoid creating a "patchwork" of complicated, and sometimes conflicting, federal and state regulations with which an entity must comply.[151]

This provision could include the required elements of an alternative compliance program that would serve as an alternative standard. For purposes of this proposal, EPA assumes a 1.18 percent component leak rate and estimates that its fugitive emissions program will achieve an 80 percent reduction level with a quarterly monitoring program, 60 percent reduction level with a semi-annual monitoring program, and a 40 percent reduction level with an annual monitoring program.[152] EPA could benchmark an alternative standard off this leak rate and the anticipated emissions reductions EPA expects to achieve through this rulemaking. EPA can readily make a finding of efficacy for those fugitive emissions programs that achieve or exceed this performance requirement.

TXOGA appreciates the need for any alternative standard to be enforceable and welcomes the opportunity to engage with EPA on the details of the elements of monitoring and enforceability.

[151] We also note that the same concept should apply to enforceable state that cover other aspects of this proposed rule including, for example, RECs, pneumatic controllers, and pneumatic pumps.

[152] *See* EPA, *Control Technique Guidelines for the Oil and Natural Gas Industry (Draft)* at 8-6, 9-19 (Aug. 2015) (cost estimates based on the "assum[ption] that 1.18 percent of the components leak"); 80 Fed. Reg. at 56,640 ("[U]sing engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, <u>we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program</u>. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, <u>we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency</u>, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies."); *see also id.* at 56,635.

b. EPA Should Provide for Alternative Compliance Relying on State and Corporate Programs Under CAA Section 111(h)(3).

CAA Section 111(h)(3) provides that, "after notice and opportunity for public hearing," EPA may permit the use of an "alternative means of emission limitation" that will achieve an equivalent reduction in emissions of any air pollutant.[153] Accordingly, relying on Section 111(h)(3), EPA should include a provision in the final rule by which an company could apply to have a fugitive emissions program designated as an alternative means of emission limitation. Should EPA adopt this approach, it should provide that any fugitive emissions program that has equivalent or better performance, based on the 1.18% leak rate assumed in EPA's analysis and anticipated reductions expected. achieves the same performance (*i.e.*, 1.18 percent leak rate and anticipated emission reduction resulting from this rulemaking). TXOGA is open to engaging in a dialogue with EPA regarding the required documentation for owners and operators to demonstrate equivalency as well as mechanisms for enforcement and streamlined approval. We also request that EPA model the concept set forth in NSPS Subpart Ja, which provides in Section 103a(j)(5) that *manufacturers of equipment* used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements for the standard. Under this provision, a manufacturer can obtain a nationwide determination so that each individual source that wants to use the manufacturer's equipment is not required to "apply" with the attendant procedural requirements. A similar approach could be used so that a company with operations in numerous states could have its program sanctioned by EPA and individual sites could then use that program without further approval by the Agency.

c. EPA Should Also Create Applicability Criteria Relying on Requirements Under CAA Section 111(h)(1).

A third option available to EPA is to include a provision similar to the approach used in Subpart OOOO regarding hydraulic fracturing, in which EPA created a regulatory off-ramp for sources that were doing green completions. Here, EPA could find that facilities that have implemented and are complying with state or corporate fugitive emissions programs that achieve the same emission reductions as the federal program are not affected facilities. As with the other options outlined above, this provision would allow owners and operators with successful existing LDAR programs in place to continue to advance these programs and, at the same time, achieve the emission reductions EPA anticipates will be achieved through the federal LDAR program. Here again, EPA could benchmark the performance standard by which applicability of the LDAR provisions would be determined according to the 1.18% leak rate assumed in EPA's analysis and the anticipated leak rates EPA expects to achieve through this rulemaking.

A further option would be for EPA to include a provision like that included in Subpart OOOO, in which EPA created a regulatory "off-ramp" for sources that do green completions. In the context of Subpart OOOOa, EPA could find that facilities that have implemented and are complying with state or corporate fugitive emissions programs that achieve the same leak rate goals as intended by the federal program are not affected facilities.

[153] 42 U.S.C. § 7411(h)(3).

This provision would allow owners and operators with successful existing LDAR programs in place to continue to advance these programs. TXOGA welcomes the opportunity to engage in a dialogue with the agency regarding the appropriate recordkeeping and reporting requirements.

In sum, TXOGA urges EPA to consider including an alternative compliance option in the final rule. Precedent as well as a host of sound policy reasons exist to support adopting all of the approaches outlined above and TXOGA is ready to engage in a dialogue with EPA regarding these and other options to support continued implementation of existing corporate programs. Indeed, the broad scope, complicated frequency, recordkeeping burden, and prescriptive timeframes for inspections outlined in the proposed rule for new, modified, and reconstructed sources will result in an inefficient inspection program, likely diverting resources from current existing source programs that companies are implementing even though they are not required by regulation. We note .

6. TXOGA Agrees that Low-Production Well Sites Should be Excluded from the Standards for Fugitive Emissions.

EPA proposes to exclude "low production well sites" from the fugitive emission standards.[154] A "low production" well is defined "as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613(c)(6)(E)."[155]

In support of this proposal, EPA correctly notes:

> We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved.[156]

EPA solicits comment on the appropriateness of this threshold for applying the standards for fugitive emissions at well sites.[157]

TXOGA supports the concept of a low production well exclusion. Imposing controls on low production wells is not cost-effective and the opportunity for reduction is not meaningful. Nor can it "reasonably be expected to serve the interests of pollution control without being

[154] 80 Fed. Reg. at 56,639 ("We are proposing to exclude low production well sites (i.e., a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for fugitives emissions from well sites.").
[155] 80 Fed. Reg. at 56,639 n.106.
[156] 80 Fed. Reg. at 56,639.
[157] *Id.*

exorbitantly costly."[158] As EPA correctly observes, the burden placed on smaller operators, many of whom are TXOGA members, would be great and the potential for emission reduction trivial.

While TXOGA supports the proposed exclusion, we note that it is important for the rule to define barrel of oil equivalent ("BOE") in terms of units of U.S. petroleum barrels of oil per cubic feet of gas to avoid confusion arising out of the different conversion rates available.

Finally, while we support the exclusion, it is most useful as an off-ramp for leak detections since any low volume production is also indicative that a well is approaching the end of its life. In such cases, any fugitive monitoring is not going to be achieving emission reductions that EPA would estimate for a well at normal production levels. Therefore, monitoring would not be cost-effective under CAA Section 111 and the BSER standards EPA and the courts have established. Similar to allowance for storage vessel control removal, TXOGA recommends cessation of leak detection applicability if less than 15 BOE/day production is sustained continuously for any 12 month period.

7. The Schedule and Frequency of Initial and Periodic OGI Surveys, Fugitive Emissions Monitoring, and Repair Requirements for Well Sites and Compressor Stations is Overly Burdensome.

a. There Should Be a One-Year Phase Upon Initial Issuance of the Regulation.

The initial implementation of the regulation will require training and startup time (including obtaining approval of corporate leak detection programs as discussed above. Accordingly, it is important for EPA to provide an initial one-year phase in of these requirements. This will allow companies to obtain equipment, train personnel, and obtain appropriate contractors. Absent this phase-in, the rule will not be achievable and will fail the BSER test.

b. Initial Surveys and Commencement of Fugitive Emissions Monitoring Should Be Required Within 180 Days After the Date of Startup Or the Date a Modified Affected Facility Begins Operation.

In numerous instances in the proposal, EPA introduces substantial and burdensome initial survey requirements:

> For new well sites, the initial survey would have to be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, the initial survey would be required to be conducted within 30 days of the site modification.
>
> …

[158] *Essex Chem.*, 486 F.2d at 433.

> The proposed standards would require that operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. We are proposing a 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey.
> …
> For new compressor stations, the initial survey would have to be conducted within 30 days of site startup. For modified compressor stations, the initial survey would be required within 30 days of the site modification. After the initial survey, surveys would be required semiannually.
> …
> The proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station. We are proposing 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey.[159]

EPA appropriately solicits comment on whether 30 days is an appropriate period for conducting an initial survey and initiating fugitive emissions monitoring.[160] TXOGA believes that 30 days is not appropriate. These requirements will be costly, the time constraints will overwhelm operators, and will prove impractical.

As an initial matter, the proposed rule does not provide a definition of "the end of" a well completion or the date the site "begins production." These omissions are important because, as written, the rule does not take into account the fact that wells may be shut in temporarily after completion. Nor does it account for the extended flow back period a well may undergo, during which crude oil may be produced to a flowback separator or test separator for a long period of time.

Moreover, the 30-day timeline for conducting an initial survey will not capture that facility's emission profile. This is because production and equipment is often phased in. Similarly, startup may be delayed beyond this 30-day period. Further, construction may not be completed within 30 days given that production is evaluated within the first 30-days of startup to determine whether any storage vessels will be deemed affected facilities and the 60-day window to install a control device, if needed.

We also note that facilities that are ramping up production may install new wells at regular intervals and this 30-day requirement will become extremely costly and result in unreasonable inspection intervals. For owners or operators actively adding well sites, site surveys will necessarily take place at a high frequency – potentially at less than 30 day intervals. The initial survey requirements are compounded by requirements that initial surveys be

[159] 80 Fed. Reg. at 56,612, 56,638-39, 56,613, 56,643.
[160] *Id*.

conducted for tank batteries when those are added. At the same time, area-wide surveys will be conducted that should capture the same information. These requirements seem to be duplicative. Facilities should be able to maintain regular monitoring schedules to avoid the cost of surveying individual well sites on a piecemeal basis when regular area-wide surveys are already being conducted that will capture these same emissions.

Accordingly, EPA needs to base the initial survey on a sufficient period of time after the start up of production. It should not be based on the date of well completion. As a general matter, the period of time for completion of initial surveys and commencement of fugitive emissions monitoring of new or modified well sites and compressor stations should be no less than 180 days after the date of startup or within 180 days after the date a modified affected facility begins operation. Initial surveys of new or modified well sites and compressor stations should not be required any sooner than 180 days after the date of startup or 180 days after the date a modified affected facility begins operation. Over time, as this rule continues to be in effect, 180 days for initial monitoring also helps integrate the new or modified site into the existing schedule for scheduled monitoring for other wells in the area. It will take unnecessary and costly extra resources in equipment and manpower to require initial 30 day monitoring for every new well, when area-wide scheduled monitoring for other sites already subject to leak detection requirements may be set to occur a short time period afterwards. It is more efficient to work new wells into an existing monitoring schedule, than to have randomly occurring monitoring for single new sites.

c. Any Fugitive Emissions Monitoring Requirement Should Be On a Fixed Annual Basis.

The preamble states that the rule proposes "new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) [to] conduct fugitive emissions surveys semiannually with OGI technology and repair the sources of fugitive emissions within 15 days that are found during those surveys."[161] At the same time, EPA proposes "OGI monitoring surveys on an annual basis for new and modified well sites" and requests comment on "OGI monitoring surveys on a quarterly basis for both well sites and compressor stations." [162] Furthermore,

> [u]nder this proposal, the required survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during a survey, while the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey.[163]

These requirements would be carried out through the development and implementation of a monitoring plan.

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[161] 80 Fed. Reg. at 56,595-96.
[162] *Id*. at 56,596.
[163] *Id*.

Any periodic OGI monitoring should be on a fixed annual basis. TXOGA agrees with the information presented by the American Petroleum Institute in support of this provision which show the diminishing returns of OGI and the importance of focusing on the high emitters. In sum, the API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates. We note that EPA's proposed variable approach where annual monitoring could be used when there is a less than 1 percent leak rate is unworkable because it requires the tracking of component counts for validation.

To the extent EPA nonetheless proceeds with a semi-annual requirement, it is essential that any program involve representative monitoring and provide for reduction in frequency when results that indicate low leak rates are obtained.

d. Method 21 Should Be Allowed As an Alternative to OGI and the Method 21 Leak Threshold Should Be 10,000 ppm Or Indication of a Leak as Determined Using the Alternative "Bubble Check" Procedure in Method 21 (see section 8.3.3 of Method 21).

EPA solicits comment on the option for using Method 21 as an alternative to OGI and the leak threshold that would apply.[164] TXOGA supports a Method 21 option because there may be instances in which an owner or operator would elect to use Method 21 due to issues with OGI or other concerns.

The lower detection threshold of OGI and the Method 21 leak thresholds should be 10,000 ppm. It is also important that in allowing Method 21, EPA include the alternative "bubble check" screening procedure for fugitive emission monitoring. The alternative EPA approved procedure provided in Section 8.3.3 of Method 21 is based on the formation of bubbles in a soap solution that is sprayed on a potential leak source. The bubble check procedure may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. For flanges, connectors and certain other fugitive emission components, a leak may be defined by the formation of bubbles in soap solution. Subsequently, the elimination of the formation of bubbles indicates no leak. In sum, the option to perform Method 21, including the alternative bubble check procedure, should be allowed to provide flexibility and a reasonable cost-effective alternative to OGI.

e. EPA Should Require Only a Corporate Monitoring Plan and Not Site-Specific Monitoring Plans.

The proposal would require the fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for

[164] 80 Fed. Reg. at 56,612.

locating sources of fugitive emissions and the detection technology to be used.[165] A company would be able to develop a corporate-wide monitoring plan, although there may be specific information needed that pertains to a single site, such as number and identification of fugitive emission components.[166] The monitoring plan would need to include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, EPA seeks comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.[167]

As discussed above, EPA should be adopting an alternative standard or alternative compliance demonstration mechanism that allows for corporate plans that have already been or will be developed to satisfy the requirements of the rule. In addition, TXOGA believes that the proposed unit by unit elements of the plan are onerous and need to be cut back. The use of corporate monitoring plans that achieve the overall objectives of the rule is far more appropriate and should be allowed.

f. Repair and Re-Monitoring Schedules Need to be Longer Than 15 Days.

Under the proposal, an owner or operator would be required to repair or replace a source of fugitive emissions "as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions."[168] EPA solicits comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites.[169] EPA indicates that it is proposing the 15-day period because that is the period of time it has historically allowed for repair/resurvey in LDAR programs, and that this indicates such timing would be appropriate here as well, in addition to citing the number of components at a well site and the number that would need to be repaired."[170] The same rationale is used to support a 15-day requirement for compressor stations.[171]

At least 30 days should be provided for repair and re-monitoring under these provisions. Moreover, extensions should be available for remotely located well-sites and compressor stations. While EPA has typically had 15-day periods for repair and re-monitoring in other rules, those rules apply at operating plants that contain numerous process units and are continuously staffed. The unique characteristics of the oil and gas industry need to be taken into consideration in establishing schedules. In addition, remote well sites present an even more unique case. The rule needs to take into account the remoteness of sites and the difficulties that owners and operators may face at certain times of year due to weather and resource availability in reaching these sites and achieving repair and re-monitoring.

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[165] *Id*.
[166] *Id*.
[167] *Id*.
[168] 80 Fed. Reg. at 56,612, 56,613, 56,637, 56,642.
[169] *Id*. at 56,637, n.104.
[170] *Id*. at 56,637, n.103.
[171] *Id*. at 56,642, n.114.

8. Digital Photograph Logs and Other Records Should Not Be Required.

For affected well sites and compressor stations subject to initial and periodic fugitive emission surveys, the proposal would require that both records and reports contain one or more digital photographs of each required monitoring survey being performed. These digital photographs must include the date taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file.[172] As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.[173] EPA states that it believes that digital pictures and frame captures can help ensure that OGI for fugitive emissions is being performed properly and requests comment on the viability and benefits of this approach, as well as the areas to which it might be expanded.[174]

The proposal would require digital photographs and logs to be available at the affected facility or the field office, and EPA solicits comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely.[175] And, although the preamble states that a photograph of every component that is surveyed during the monitoring survey is not required,[176] the proposed rule language appears to require digital photographs of each fugitive emissions component and each leak observed.[177]

EPA should delete the requirement for digital photographs in any final rule issued because it will impose significant costs and, more importantly, will not provide an effective means for ensuring that fugitive emission OGI is being performed properly. Furthermore, such a requirement would add an unnecessary burden on owners and operators and provide no real environmental benefit. These photographs will not provide any additional compliance assurance that the survey requirements were met. Indeed, photographs cannot demonstrate that an appropriate survey was conducted and that proper repairs were performed. The operator's certification, relevant procedures, and repair documentation provides the suitable assurance that an OGI survey has been conducted.

Moreover, photographs of fugitive emissions monitoring activities will necessarily capture more information than would otherwise be publicly available. These images may contain confidential business information. If made available to the public, these photographs could inadvertently pose a security risk to the facility and raise concerns over vulnerability to terrorist activities, retaliation attempts, and anti-competitive activities. Oil and natural gas facilities are generally unmanned and are not protected by fences, gates or other security measures. In addition, permitting agencies will inevitably begin receiving FOIA requests for

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[172] *Id*. at 56,615, 56,651; *see also* Proposed C.F.R. § 60.5397a(k)(6), 80 Fed. Reg. at 56,669.
[173] *Id*.
[174] 80 Fed. Reg. at 56,652-53.
[175] *Id*. at 56,615.
[176] *Id*.
[177] Proposed C.F.R. § 60.5397a(k)(6), 80 Fed. Reg. at 56,669.

these photographs for reasons unrelated to fugitive monitoring. If EPA chooses to require that photographs be submitted as part of its electronic reporting requirement, interested members of the public can – and will – submit Freedom of Information Act requests for these photographs for reasons unrelated to fugitive emissions monitoring, making a huge amount of detailed information about these oil and gas facilities available to the general public. TXOGA therefore urges EPA to eliminate the digital photograph recordkeeping requirement in its entirety. To the extent that EPA nonetheless proceeds with requiring digital photographic records, EPA should not require such photographs or other digital images to be uploaded to permitting agencies. Even if digital photographs could be justified, which they cannot, the cost of collecting and storing such images (which would be significant) would mean that it would not survive a BSER cost analysis. We note that EPA has not provided any cost analysis on this issue.

While EPA appears to be concerned that owners or operators would claim that OGI monitoring was conducted without having actually surveyed the well site or compressor station, this concern is not supported by any evidence in the record that companies would commit what is essentially fraud. TXOGA members operate in a highly regulated environment, even those that are smaller businesses. There is no basis for EPA to assume that companies would falsify the required certifications under Section 60.5420a(b)(1)(iv). Numerous federal CAA programs require inspections, LDAR, and other work practices but do not require digital proof of monitoring. This requirement goes far beyond anything that is necessary to provide a reasonable assurance of compliance.[178]

Finally, we note that this requirement could raise First Amendment concerns for owners and operators, as some employees or contractors possess religious beliefs that do not permit them to have their photograph taken. A categorical requirement that photographs be taken with the operator in the photograph as a form of compliance verification may violate these individuals' right to freely practice their respective religions. Companies are not permitted to discriminate on the basis of their employees' religions and cannot impose this requirement on those employees whose religions prohibit photographs. TXOGA urges EPA to rely on other, less oppressive, potentially unconstitutional, and at least controversial requirements.

Simply put, EPA should eliminate any digital photograph requirement from the final rule because it will provide no additional environmental benefit or compliance assurance and represent a substantial burden to regulated entities.

[178] EPA established in the Compliance Assurance Monitoring (CAM) Rule that the criterion against which monitoring is to be evaluated is based on whether it will " provide a reasonable assurance of compliance." 40 C.F.R. § 64.3(a). In addition, Title V establishes that EPA's authority for monitoring to conditions that are "conditions as are necessary to assure compliance." 42 U.S.C. § 7661c(a).

9. Audit Programs and Independent Third-Party Verifications

a. There Is No Need for an Expensive Third-Party Audit Program and it Will Not Achieve the Ends EPA Seeks.

EPA solicits comment on establishing third-party verification of the required fugitive emissions monitoring program, though this is not included in the proposed rule regulatory provisions.[179] According to the preamble, the third-party audit program would provide a structure in which the facilities themselves are responsible for determining and documenting that their auditors are "competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators."[180] EPA also requests comment on one or more alternative approaches, such as "requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols."[181] EPA also states that there would be a need for a mechanism "to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration."[182]

EPA postulates that a third-party audit program would provide verification to a regulator that a regulated entity is meeting one or more of its compliance obligations such that the regulator could give "significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight."[183] Specifically, EPA states that "[w]hile requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance."[184]

EPA's premise that third-party audits will improve compliance is a mere assertion that is not supported in the record. While it may be true that audits improve compliance, EPA has not supported the conclusion that *third party audits* increase compliance. What is indisputable is that a third-party audit requirement will dramatically increase the costs of the program. Indeed, expensive, consultant-driven audits will have a negative competitive impact on smaller, less-funded operators in an already-competitive industry with declining oil and gas prices. Any approach should recognize that audits will already strain available resources and that third party auditing requirements will potentially threaten viability of some operators without a corresponding increase in compliance. Any requirement for third-party audits will need to demonstrate that there is a quantifiable increase in emissions reductions that is justified based on a cost-effectiveness analysis.

[179] 80 Fed. Reg. at 56,648-50.
[180] *Id*. at 56,648-49.
[181] *Id*. at 56,649.
[182] *Id*. at 56,648.
[183] *Id*.
[184] *Id*.

Because EPA has also failed to include in the proposal an analysis of the cost of a third-party verification system or any proposed regulatory provisions, a third-party audit program cannot be included in the final rule. As discussed above in Section III(G), *supra*, commenters cannot evaluate based on the information EPA has provided the costs of a third party audit program or the regulatory and compliance implications of such a program. The proposal does not provide adequate notice of the requirements because it contains no details regarding how the verification system would work. Thus, commenters are unable to provide meaningful comment on the scope of the program, estimated cost levels, workability, and other factors that would need to be considered.[185] EPA has failed to demonstrate the benefit to using third-party verifiers, or provide an analysis of associated cost and impacts, thus the record does not support including such a requirement in the final rule.

b. Auditor Competence

The preamble stipulates that to ensure the competence of the auditor, certain criteria should be met, for example:

> Competence of the auditor can include safeguards such as licensing as a Professional Engineer (PE), knowledge with the requirements of rule and the operation of monitoring equipment (*e.g.*, optical gas imaging), experience with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and training or certification in auditing techniques.[186]

With respect to auditor competence, PE licensure does not equate to competence in the upstream oil and gas industry nor in fugitive emissions mitigation and OGI. The most important criteria related to OGI technician competence are training and experience with OGI technologies, in general, and direct hands-on experience in the oil and gas industry, in particular. It should not be necessary that an OGI technician hold a bachelor of science in Engineering and for those engineers who are employed as OGI technicians, it should not be necessary to hold PE licensure. Such a stringent requirement would eliminate nearly all currently practicing and highly competent OGI technicians and would be the equivalent of requiring an ultrasound technician to hold a medical degree. A focused and reasonable training program would be reasonable to assure competency in the proper operation of OGI instrumentation, optimal ambient conditions for OGI surveys, and operation of oil and gas well site and compressor station equipment and operations.

c. Auditor Independence

EPA also stipulates that to ensure the independence of the auditor, certain criteria should be met, including "provisions and safeguards in the contracts and relationships between the owner and operator of the affected facility with auditors."[187] Such criteria can include:

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[185] *See Donner Hanna Coke Corp.*, 464 F. Supp. at 1305; *see also Kennecott Corp.*, 684 F.2d at 1019.
[186] 80 Fed. Reg. at 56,649.
[187] *Id*.

> The auditor and its personnel must not have conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years; the auditor and its personnel must not provide other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report; and all auditor personnel who conduct or otherwise participate in the audit must sign and date a conflict of interest statement attesting the personnel have met and followed the auditors' policies and procedures for competence, impartiality, judgment, and operational integrity when auditing under this section; and must receive no financial benefit from the outcome of the Audit, apart from payment for the auditing services themselves.[188]

EPA postulates that these provisions will "minimize audit bias." EPA also suggests that reports would be submitted to EPA simultaneously with submittal to the owner/operator.[189] EPA fears of auditor bias are grossly overblown, particularly in light of the fact that EPA has not demonstrated that a third party audit, much less one subject to these extreme independence-verification provisions, would actually improve compliance. EPA's suggestion that previous inclusion of such requirements in consent decrees is some indication that they are effective is not only inappropriate, but it also makes no sense.[190] The fact that a company might agree in the context of a consent decree to a particular requirement does not indicate that the requirement is effective, reasonable, cost-effective, or otherwise sufficient to satisfy the elements that EPA must establish to show that it has met the statutory criteria for a standard under Section 111.

It is worth noting that EPA has not demonstrated a rationale justifying an arbitrary exclusion period defining independence. Excluding auditing contracting firms or auditors based on performance of past research, development, design, construction services, or consulting for the owner or operator within the last 3 years is not practical and would unnecessarily narrow the pool of qualifying and competent auditors available to the industry. Independence can be achieved without an arbitrary exclusion period (*i.e.*, 3 years). For example, the Board of Environmental, Health & Safety Auditor Certifications (BEAC) sets guidelines for achieving independence that do not involve exclusion periods.

A third-party or internal audit program should be optional for owners and operators. EPA should not prevent companies from conducting internal audits using competent and objective auditors.

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[188] *Id*. (emphasis added).
[189] *Id.* at 56,650.
[190] *Id*.

D. Hydraulically Fractured Oil Well Completions

1. EPA Should Not Prescribe Threshold Criteria to Define Technologies That Are "Technically Feasible" for Reduced Emission Completion (REC).

EPA should not prescribe a particular technological system that must be used to comply with a standard of performance for REC. Rather, EPA should set the standard of performance for REC, consistent with Section 111(a)(1) of the Act, and owners and operators should have the flexibility to meet that standard using any means that are feasible. Furthermore, EPA should not prescribe arbitrary criteria or thresholds defining feasibility. Owners and operators should be allowed to select any measure or combination of measures that will achieve the emissions level of the standard.

Proposed Section 60.5375a(a)(1)(ii) requires that a REC be conducted, except if it is "technically infeasible" to route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.[191]

We are concerned that the term "technically feasible" could be broadly interpreted in practice after the rule is issued. Feasibility of meeting REC provisions of Section 60.5375a(a)(1)(ii), most importantly the feasibility of capturing and routing the recovered gas from a hydraulically fractured well to a gathering system pipeline, includes economic and many other considerations in addition to "technical" considerations.

EPA solicits comment on criteria that could help clarify availability of gathering lines, stating that availability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells and that there are several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line.[192] EPA notes that Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline and solicits comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold as well as on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.[193] Further, EPA solicits comment on:

> whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for

[191] Proposed Section 60.5375a(a)(1)(ii), 80 Fed. Reg. at 56,665.
[192] 80 Fed. Reg. at 56,634.
[193] *Id*.

> such a threshold. In addition, we solicit comment on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.[194]

As noted by EPA, there are numerous technical and other factors contributing to the complexity and overall feasibility of conducting REC.

Regarding gathering pipeline availability, development of surface equipment and pipeline infrastructure may lag behind well completion schedules for many reasons. Wells may be drilled, completed using hydraulic fracturing and then shut in for a time. Operators may be obligated to put an oil well on production before a gas pipeline is in place in order to hold the lease. Wells may flow back for an extended period to prove technical and/or economic viability of producing the well to surface equipment. New oil wells may produce unexpected volumes of associated gas.

In the preamble to the final Subpart OOOO rulemaking, EPA responded to commenters concerned that "language in 40 CFR 60.5375(a)(1) and (2), stating that source owners or operators should ''minimize the emissions associated with venting of hydrocarbon fluids and gas'' and that "[a]ll salable gas must be routed to the gas gathering line as soon as practicable" is vague." EPA agreed that prescribing specific equipment to accomplish a reduced emissions completion is not necessary and has revised the rule language to not prescribe specific equipment. The operational standards provided in the NSPS allow the operator flexibility to perform the REC using equipment and practices best determined by the operator.[195]

EPA has noted its belief that owners and operators of gas wells subject to 40 CFR 60.5375(a) that require REC for a portion of the flowback period will exercise due diligence in coordinating the completion event with availability of a flow line to convey captured gas to market. However, there may be cases in which, for some reason, the well is completed and flowback occurs without a suitable flow line available. In those isolated cases, we believe 40 CFR 60.5375(a)(3) provides for gas not being collected and instead combusted or vented pursuant to that section.[196]

Availability of gathering system pipelines is most often out of the control of the producer. Gathering system pipelines that would be used for REC and sales of natural gas are in many cases operated by a third party.[197] There are right of way issues when crossing private, tribal, state or federal lands administrated by the Bureau of Land Management that can take years to resolve. Contractual issues may also arise. An existing pipeline may be at or near capacity, affecting reliable availability. There may be multi-jurisdictional issues for sites located near the boundary of Indian Country.

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[194] *Id*.
[195] 77 Fed. Reg. at 49,517..
[196] *Id*.
[197] This issue is not exclusive to oil wells; gathering system accessibility at the time of a REC is also a concern for gas wells.

Feasibility of routing recovered gas from a well completion flow back to a gas gathering system pipeline cannot hinge on an arbitrary distance from the well to that pipeline or any other threshold criteria. Each and every well presents unique circumstances related to reservoir characteristics, surface conditions and numerous technical and non-technical factors.

The cited Administrative Rules of Montana, ARM 17.8.1603, apply to production, not to hydraulically fractured well completions. ARM 17.8.1603(a) requires

> volatile organic compound (VOC) vapors greater than 500 British thermal units per standard cubic foot (BTU/scf) from oil and gas wellhead equipment must be routed to a gas pipeline, or, if a gas pipeline is not located within a 1/2 mile of the oil and gas well facility, VOC vapors greater than 500 BTU/scf must be captured and routed to emissions minimizing technology or to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system; . . .

Montana's requirement is based on the intrinsic properties of the produced gas (heating value, BTU/scf) and not the volume produced. As a consequence, even crude oil wells producing very small amounts of associated gas would be required to compress and pipe such gas to a local pipeline. The technical and economic feasibility of meeting ARM 17.8.1603(a) aside, EPA should not require producers to connect to a pipeline gathering system purely based on an arbitrary linear distance to such system. As noted above, pipeline gathering systems are typically owned and operated by an entity other than the producer. Also as discussed above, there are many factors considered in whether or not connection to an existing pipeline is feasible.

Establishing a bright line for overall feasibility of conducting REC for oil wells is not practical. Owners and operators should have the option, based on technical, economic and other factors, to use a completion combustion device to reduce methane and VOC emissions from hydraulically fractured oil well completions.

EPA should revise the term "technically feasible" in proposed Section 60.5375a(a)(1) to simply "feasible" and EPA should not set threshold criteria for "feasibility" but rather should leave that to case-by-case assessment.

2. EPA Should Clarify That if There Is No Separator Phase, Corresponding Requirements Are Inapplicable.

EPA solicits comment on:

> (1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells. We solicit further information that would help inform our consideration of

> this issue as we seek to ensure we have adequately established appropriate requirements for all well completions subject to the NSPS.[198]

EPA also solicits comment on the types of oil wells for which owners and operators will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (*e.g.*, horizontal, vertical, directional).[199]

TXOGA notes that in some instances, when fracturing a well at an existing site, an operator may proceed directly from the initial flowback phase to the production phase, without having a separation stage. Under these circumstances, there is no separator flowback phase. TXOGA interprets the proposed regulatory provisions to make these recordkeeping requirements inapplicable. Simply put, there would be no process for which to create a record. It would be helpful for EPA to confirm this interpretation in the preamble to the final rule, such that owners and operators need only comply with the requirements applicable to each stage of the process that in fact occurs. Here, the only requirements applicable to the initial flowback phase and production phase apply.

3. TXOGA Supports the Proposed GOR Threshold and Recommends a Definition of GOR Be Included in Any Final Rule.

EPA is proposing that wells with a "gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS."[200] EPA solicits comment on whether a GOR of 300 is the appropriate applicability threshold, and if the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. Specifically, EPA states,

> We believe that having no threshold may create a significant burden for operators to control emissions for these wells with just a trace of gas. EIA data show that the number of 'oil only' wells drilled from 2007–2012 was less than 20 percent. The potential emission characteristic of oils with a GOR of 300 is relevant when deciding whether this is a reasonable threshold.[201]

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[198] 80 Fed. Reg. at 56,634.
[199] *Id*. at 56,633 n.89.
[200] *Id*.
[201] 80 Fed. Reg. at 56,633.

EPA notes that on February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.[202]

TXOGA supports the GOR threshold and recommends that EPA provide a definition of GOR in Section 60.5430a to mean the volume of natural gas produced at the surface at standard conditions, standard cubic feet (scf), divided by the volume of hydrocarbon liquids produced at the surface at stock tank conditions, stock tank U.S. petroleum barrel, bbl. This definition would be consistent with, and further clarify, the definition set out in 40 C.F.R. part 63 Subpart HH—NESHAP from Oil and Natural Gas Production Facilities, Section 63.761. The proposed definition is also widely understood in the industry and consistent with a series of articles published by William D. McCain *et al.*, which are cited extensively by EPA in its rulemaking pertaining to Subpart HH.

4. EPA Should Provide a New Low-Pressure Well Definition.

EPA addresses low pressure wells in the following way:

> Consistent with the current VOC standards for hydraulically fractured gas wells, we are proposing that 'low pressure' wells would remain affected facilities and would have the same requirements as subcategory 2 wells (wildcat and delineation wells). The term 'low pressure gas well' is unchanged from the currently codified definition in the NSPS; however, we solicit comment on whether this definition appropriately indicates hydraulically fractured oil wells for which conducting an REC would be technologically infeasible and whether the term should be revised to address all wells rather than just gas wells.[203]

EPA should provide a new definition of "low pressure oil well" to differentiate oil wells versus gas wells. The definition of "low pressure well" set out in proposed Section 60.5430a and taken from the definition of "low pressure gas well" in Subpart OOOO (Section 60.5430) is not appropriate for a low pressure oil well. In the current subpart OOOO, the term low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the true vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.[204]

Low pressure oil wells may not produce enough gas to merit sales; hence there would not be a gas gathering system available for a REC nor sufficient gas to operate a separator. In addition, TXOGA requests that EPA include an exemption for wells on mechanical artificial lift. While the universe of wells that would need this exemption may be narrow, we request that EPA develop an exemption that addresses the mechanical artificial lift issue, since there are situations where BSER is not a combustion device because of the level of flow.

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[202] *Id*. at 56,633 n.92 (citing API Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule (Feb. 24, 2015), EPA-HQ-OAR-2014-0831).
[203] 80 Fed. Reg. at 56,611.
[204] 40 C.F.R. § 60.5430.

E. EPA Should Implement Revisions to the Requirements and Definitions for Storage Vessels, Covers, Closed Vent System and Controls.

1. The Approach to Thief Hatches and Closed Vent Systems Should Be Revised.

EPA provides in the proposal that for storage vessel affected facilities for which a control device is used to control VOC emissions, owners and operators must equip the storage vessel with a:

> cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412a(c) and (d).[205]

In addition, EPA would require that the cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) must form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system; that each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening and that each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated.[206]

Each closed vent system must be designed:

> to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process. (2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater."[207]

> If the control system (closed vent system and control device, including pressure relief devices and thief hatches on storage vessels) cannot accommodate the peak instantaneous flow rate of flash emissions, working losses, breathing losses and any other additional vapors, this may cause pressure relief devices and thief hatches to "pop" and they may not properly reseat, resulting in immediate and potentially continuing excess emissions. Through our energy extraction

[205] Proposed 40 C.F.R. § 60.5395a(b)(1), 80 Fed. Reg. at 56,667.
[206] Proposed 40 C.F.R. §60.5411a(b), 80 Fed. Reg. at 56,676.
[207] Proposed 40 C.F.R. §60.5411a(c) , 80 Fed. Reg. at 56,676.

> enforcement initiative, we have seen this to be the case, due in large part to undersized control systems that may have been inadequately designed to accommodate only working and breathing losses of a storage tank.[208]

Production tanks receiving produced liquids, including crude oil, hydrocarbon condensate, produced water or mixtures thereof are generally equipped with a "thief hatch." Thief hatches, which are designated as openings to a "cover," function to provide access to the tank, for example to "gauge" the liquid level. Many tanks are equipped with spring loaded thief hatches that also function as pressure/vacuum vents to protect the integrity of the tank by avoiding excess pressure or vacuum. The spring loaded or weighted thief hatches are designed to vent to atmosphere in the event the pressure within the tank exceeds the set point pressure, in terms of ounces per square inch (osi). Tanks may also be equipped with separate pressure relief devices that may relieve pressure to atmosphere or to a control device.

In developing these regulations, EPA needs to be aware that thief hatches present a unique situation. While it is true that they may "leak," they are also intended to open in certain situations (e.g., as pressure relief). Thus, there is a technical analysis that needs to be made as to whether or not an emissions is a "leak." This is particularly true for lower throughput volume tanks. In addition, it may be difficult, due to the intermittent nature of leaks, to determine that there is in fact a leak. Thus, one might be investigating as the 15-day deadline passes (and it is important for any deadline not to commence until there is confirmation that it is a leak and not a normal, expected emission). This issue needs to be addressed in any final rule.

Thief hatches may leak as a consequence of physical or chemical degradation or fouling of the seal material, either of the vacuum or pressure seal, or both. Both weighted and spring loaded thief hatches and pressure relief devices may fail to reseat after a relief event. In any case, the "continuous impermeable barrier" standard for covers is not achievable in practice and EPA cannot establish that this standard "is achievable under the range of relevant conditions" outlined above.[209].

EPA should define closed vent system to be consistent with definitions in NSPS Subparts VV (40 C.F.R. § 60.481) and VVa (40 C.F.R. § 60.481a) and to include thief hatches and other cover openings. The term "closed vent system" should be defined to mean "a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, access hatches, and other cover openings, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process."

To be consistent with NESHAP Subpart HH (40 C.F.R. § 63.761), EPA should define "control device" to mean "any equipment used for recovering or oxidizing hydrocarbon vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (*i.e.*, injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used,

[208] 80 Fed. Reg. at 56,649.
[209] *Nat'l Lime*, 627 F.2d at 433.

including piping, connections, and flow inducing devices, is not considered to be a control device or closed-vent system." This additional definition is needed due to EPA not being clear with respect to boilers and process heaters. Proposed rule language seems to treat boilers and process heaters as control devices which they are not and should not be subject to control device testing and monitoring required in the rule. The HH definition makes it clear when process heaters and boilers are not control devices.

Additional changes to the rule will be necessary to address the revised definition of closed vent system to include thief hatches.

2. Third-Party Engineering Evaluation of Storage Vessel Vapor Collection and Control Systems Should Not Be Required.

EPA has viewed emissions from storage vessels observed by OGI during inspections pursuant to its energy extraction enforcement initiative as indications of inadequate design and potential violations of the Act, rather than operation and maintenance issues.

> One potential remedy for the inadequate design and sizing of the closed vent system would be to require an independent third-party (independent of the well site owner/operator and control device manufacturer), such as a professional engineer, to review the design and verify that it is designed to accommodate all emissions scenarios, including flash emissions episodes. Another element of the professional engineer verification could be that the professional engineer verifies that the control system is installed correctly and that the design criteria is properly utilized in the field.[210]

The EPA requests comment on these approaches. Specifically, EPA requests comment as to whether criteria should be specified by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system, or whether "we might cite to current engineering codes that produce the same outcome." [211]

The BSER for storage vessel affected facilities has been established, and EPA should not prescribe a particular system that must be used to comply with that standard. As EPA has acknowledged, the Agency "may not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions."[212] The Agency, cannot, therefore, prescribe specific steps an owner or operator must take to satisfy the standard.

Moreover, EPA has not established a correlation between PE licensure and competence in engineering design of air pollution control systems. Requiring professional engineer (PE) licensure for the design of, or verification of "adequate design" of, production tank vapor

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[210] 80 Fed. Reg. at 56,649.
[211] *Id.*
[212] EPA, *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act*, *supra* n.68, at 2.

collection systems by a PE is a matter under the authority of state boards of professional engineers or other state entities and not the federal government.

3. EPA Should Revise Its Approach to the Requirement for Closed Vent Systems to be Operational at Least 95% of the Year.

EPA should provide operational flexibility, allowing gas/vapor to be routed to a flare or other combustion device in cases where gas/vapor cannot be routed to the pipeline or process for any reason. As proposed, 40 C.F.R. § 60.5411a(c) provides each closed vent system for storage vessel affected facility "that routes emissions to a process must be operational 95 percent of the year or greater."[213]

Many production sites are designed and intended to primarily route produced natural gas from surface separation and/or captured vapor from storage tanks to a gas gathering system under normal circumstances. However, due to circumstances beyond the control of the facility owner/operator, access to such pipeline may be restricted or unreliable. In those cases, gas may be routed to a flare or other combustion device.

Closed vent systems that do not include flow-inducing devices and that do not have bypasses are passive in nature. Such systems are always operational. It is the control device and/or the process to which gas/vapor is routed that must be operational. To provide flexibility, EPA should specify that the process to which emissions are routed must be operational 95 percent of periods when emissions may be vented from the affected facility.

4. EPA Should Not Include a Pressure Continuous Monitoring System (CMS) Requirement in the Rule.

EPA states that another approach to detecting overpressure in a closed vent system would be to require a continuous pressure monitoring device or system, located on the thief hatches, pressure relief devices and other bypasses from the closed vent system.[214] The preamble posits anecdotally that EPA inspections have shown thief hatch pressure settings below the pressure settings of the storage tanks to which they are affixed, which results in emissions escaping from the thief hatch and not making it to the control device.[215] We note that setting the relief pressure below the pressure rating of a tank may be done to ensure safety. As tanks age, having a safety factor is intended to ensure the long term integrity of the tank.

EPA also requests comment on the types of cost-effective pressure monitoring systems that can be utilized to ensure that the pressure settings on relief devices are not below the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required.[216] Fundamentally, EPA has not provided statistical information to support the application of a CMS. Further, it is unclear what would be learned or accomplished

[213] 80 Fed. Reg. at 56,676.
[214] *Id.* at 56,649.
[215] *Id.*
[216] *Id.*

by such monitoring, particularly when considering the very low increments of pressure at issue and the relative costs.

The cost of a tank pressure CMS, including the capital cost of pressure transducers and other instrumentation and data acquisition hardware, installation costs, software, Supervisory Control And Data Acquisition (SCADA) integration and IT, quality assurance and quality control measures, and routine operation and maintenance costs *etc.* would be prohibitive, particularly if required over a large geographically dispersed asset with numerous tank systems. EPA must address cost considerations in pursuing its Next Generation strategy.

Vertical fixed roof tanks operate within a narrow and low pressure/vacuum range. A pressure sensing instrument would have to detect pressure (and vacuum) conditions hovering around zero pounds per square inch gauge pressure. Also, the pressure setpoints of spring loaded thief hatches and pressure relief devices are not precise. We are aware that Noble Energy, as part of its Consent Decree, is required to install such a system, but the performance and reliability of a tank pressure CMS is unproven in practice.[217] The technological challenges and prohibitive cost outweighs the potential, and unproven, benefit.

Proper operation of storage vessel affected facilities in compliance with the promulgated standards representing BSER should be determined and documented by the inspection and recordkeeping regimen prescribed in the rule.

This requirement represents another point where EPA is required under the statute to take into account the cost of compliance and provide an exclusion that covers circumstances where the cost of compliance would be great and the expected emission reductions trivial.[218]

5. EPA Should Revise Certain of the Compliance Requirements for Storage Vessels.

For storage vessel affected facilities, owners and operators are required to reduce VOC emissions by 95.0 percent, as specified in proposed Section 60.5395a(a).[219] Continuous compliance provisions of proposed Section 60.5415(a)(e)(3), however, incorrectly specify that owners and operators must reduce methane and VOC emissions as specified in proposed Section 60.5395a(a).[220]

EPA should strike reference to methane in proposed Section 60.5415(e)(3), as the referenced standards specified in proposed Section 60.5395a(a) pertain only to VOC.

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[217] *See* Consent Decree, *United States et al. v. Noble Energy, Inc.*, No. 1:15-cv-00841 (D. D. Col.), *available at* http://www2.epa.gov/sites/production/files/2015-04/documents/noble-cd.pdf.

[218] *See, e.g.*, 42 U.S.C. § 7411(a)(1) (the best system of emission reduction should "tak[e] into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements")

[219] Proposed 40 C.F.R. § 60.5395a(a), 80 Fed. Reg. at 56,667.

[220] 40 C.F.R. §60.5415(e)(3), 80 Fed. Reg. at 56,683.

Moreover, the proposal would add in proposed Section 60.5395a(b) that process devices must reduce emissions by 95 percent, a provision that was not included in the Subpart OOOO. To be consistent with CVS, the rule would need to state that process devices must operate 95 percent of the time as they are not emissions control devices and should not be subject to emission control verification requirements.

6. EPA Should Add Certain Definitions for Storage Vessel Affected Facilities Routing Emissions to a Process.

EPA should add a definitions of "closed vent system" and "control device" consistent with NESHAP Subpart HH (40 C.F.R. § 60.761).

Closed-vent system should be defined to mean "a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (*e.g.*, to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards."

Control device should be defined to mean "any equipment used for recovering or volatile organic compound (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (*i.e.*, injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or closed-vent system."

Routing emissions to a process should not trigger initial or continuous compliance requirements applicable to control devices.

7. EPA Should Exclude Certain Produced Water Recycling Tanks and Other Process Tanks.

EPA recognizes that its proposed rule could inadvertently subject water recycling tanks to the NSPS and is "considering changes in the final rule to remove tanks that are used for water recycling from potential NSPS applicability."[221] EPA solicits comment on approaches that could be taken to amend the definition of "storage vessel" or other changes to the NSPS that would resolve this issue without excluding storage vessels appropriately covered by the NSPS. In addition, EPA solicits comment on location, capacity, or other criteria that would be appropriate for such purpose.[222]

EPA should consider adding a definition of "process vessel" in Subpart OOOOa to include water recycle tanks and other tanks. The definition of "storage vessel" set out in Subpart

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[221] 80 Fed. Reg. at 56,648.
[222] *Id*.

OOOO and the proposed Subpart OOOOa already excludes "process vessels such as surge control vessels, bottoms receivers or knockout vessels." There is no definition of process vessel in the proposal.

NSPS Subpart Kb, 40 C.F.R. § 60.111b, provides a definition of "process tank" to mean

> a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.[223]

Sour water disposal, secondary recovery (waterflood) and carbon dioxide enhanced recovery operations, for example, utilize tanks to recycle large volumes of water, which is reinjected into subsurface formations. Low volume concentrations of VOC and methane, but high volume throughput may result in high apparent working and breathing losses. Recycle tanks are generally connected to a pipeline or directly to injection wells and are operated within a narrow range of liquid levels. Operation at near constant levels minimizes working losses and operation at near-constant temperature minimizes breathing losses. In addition, such tanks provide surge capacity and may operate as oil-water separators in hydrocarbon skimming.

EPA should not establish a size threshold for water recycle tanks. Tanks associated with water recycling operations are not necessarily "very large vessels having capacities of 25,000 barrels or more," but may have design capacities of 1,000 barrels or less. EPA should consider a gas-to-water ratio (GWR) threshold in terms of standard cubic feet of gas per U.S. petroleum barrel of water. Tanks receiving water that is already stabilized such that only working and breathing losses occur could be categorically excluded.

Fundamentally, it is critical for EPA to exclude these tanks from regulation because the cost-effectiveness at the concentration levels at issue are simply not consistent with NSPS case law and EPA's historic approach to implementing NSPS rules from a cost perspective.

F. TXOGA Supports and Requests Revisions of Certain Provisions Related to Natural Gas-Driven Chemical/Methanol Pumps or Diaphragm Pumps.

TXOGA adopts the comments of the American Petroleum Institute on the cost-effectiveness of controls for pneumatic pumps and believes that the proposal does not satisfy the cost evaluation and effectiveness requirements mandated under Section 111 of the Act.

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[223] 40 C.F.R. § 60.111b.

1. TXOGA Supports EPA's Proposal Placing No Control Requirements On Pneumatic Pumps if Regulated Alone.

TXOGA supports EPA's proposal providing that owners and operators are not required to install a control device solely for the purposes of complying with the standard for pneumatic pumps.[224] EPA should, however, require that emissions from certain affected pneumatic pumps be routed to a control device only if such control device is located within the boundary of the surface site and under the control of the operator and only if such control device is required by NSPS OOOO/OOOOa for a storage vessel affected facility or other affected source. Controls should not be required for pneumatic pump affected facilities operated at a site with no other sources affected by NSPS OOOO/OOOOa. At a minimum, EPA should limit compliance requirements pursuant to the pneumatic pump standards for those control devices not already required for an affected facility other than pneumatic pumps. In addition, EPA should exclude certain pneumatic pumps from regulation, including small or limited use pumps and pumps for which controls would not be technically feasible.

The proposed standards would require the methane and VOC emissions from new, modified and reconstructed natural gas-driven chemical/methanol pumps and diaphragm pumps located at any location (except for natural gas processing plants) throughout the source category to be reduced by 95 percent if a control device is already available on site.[225] Owners and operators are not required to install a control device solely for the purposes of complying with the 95.0 percent reduction standard.[226] The proposal results in an overlap of requirements for control devices not already regulated by Subpart OOOO or OOOOa and those control devices otherwise required by the rule for an affected facility other than pneumatic pumps. The former should not be subject to standards for closed vent systems and control devices, nor to requirements for inspections, monitoring, recordkeeping or reporting. In fact, as noted above, EPA should limit applicability of the control standard for pneumatic pumps only to those sites where an NSPS OOOO/OOOOa control device is in operation.

For cases where a control device previously required for an affected facility other than a pneumatic pump is no longer required by Subparts OOOO/OOOOa for any reason, EPA should clarify that such control device would also no longer be required for any pneumatic pump affected facility.

Regarding technical feasibility and cost effectiveness, many pneumatic pumps are small and operate intermittently. EPA should exclude those pumps with an annualized emission rate less than 52.56 thousand standard cubic feet (Mscf), which is equivalent to the 6 standard cubic foot per hour (scfh) exemption threshold for pneumatic controller affected facilities. In addition, EPA should provide an exclusion from control requirements for certain pneumatic pumps for which routing emissions to a control device is not technically feasible.

[224] Proposed 40 C.F.R. § 60.5393a(b)(2), 80 Fed. Reg. at 56,666.
[225] 80 Fed. Reg. at 56,595.
[226] Proposed 40 C.F.R. § 60.5393a(b)(2), 80 Fed. Reg. at 56,666.

Pneumatic pump applicability in Section 5365a(h) should include exclusions for both small chemical/methanol injection pumps and larger diaphragm type pumps. Both exclusions should be equivalent to the emissions allowance for pneumatic controllers which is ≤ 6 scf/hr of natural gas annualized. On an annualized basis, the 6 scf/hr natural gas allowance equates to 52,560 scf/yr. For small piston type injection pumps that mostly operate well below 6 scf/hr (EPA factor in the TSD of 2.48scf/hr) no control will be required in any event. For larger diaphragm type pumps, EPA's emission rate factor in the TSD of 22.45 scf/hr of natural gas equates to about 97 days of continuous operation based on an annual limit of 52,560 scf/hr allowed for pneumatic controllers. Since many diaphragm pumps are often limited use pumps for purposes such as liquid transfer, an exemption is also appropriate for limited use situations. Allowing up to 90 days of continuous use or 2160 hours/yr of operation before any control requirement will not exceed the equivalent natural gas emissions allowed/yr for a pneumatic controller. Suggested rule text changes then for 5365a(h) are then:

> (h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump **with emissions greater than 52,560 scf per yr of natural gas (where natural gas is a surrogate for methane and VOC)** or a natural gas driven diaphragm pump **operating more than 2160 hrs/yr.**
>
> (2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump **with emissions greater than 52,560/yr of natural gas (where natural gas is a surrogate for methane and VOC)** or natural gas-driven diaphragm pump **operating more than 2160 hrs/yr.** for which a control device is located on site.

We note that EPA should make any conforming changes to 60.5365a(d)(1) and (2) to ensure that natural gas is being treated as a surrogate for methane and VOC and is not treated as an independently regulated pollutant.[227]

2. EPA Should Not Regulate "Gas Assisted" or "Energy Exchange" Glycol Pumps Via Subpart OOOOa.

EPA is requesting comment and additional information on the level of uncontrolled emissions from glycol pumps, how these pumps are vented through the dehydrator system, and the amount and characteristics of VOC and methane emissions from uncontrolled glycol dehydrators.[228]

> Our understanding is that emissions from glycol dehydrator pumps are not separately quantified because these emissions are released from the same stack as

[227] TXOGA does not concede that natural gas could in fact be treated as a "pollutant" within the meaning of the provisions of the Clean Air Act.
[228] 80 Fed. Reg. at 56,627.

> the rest of the emissions from the dehydrator system, which are regulated under the NESHAP at 40 CFR part 63 HH and HHH.[229]

"Gas assisted" or "energy exchange" pumps are a cost-effective and proven technology widely used by the industry for remote locations where there is no power available. Through EPA's Natural Gas STAR program and other published studies it is well understood that gas (methane) entrained in the rich glycol is released in the rich glycol separator, if present, or in the glycol regeneration process via the reboiler. For glycol dehydration units that are uncontrolled, methane may be emitted to the atmosphere either from the rich glycol separator vent, if present and when the relief pressure setting is exceeded and/or from the reboiler still vent.

Emissions from "gas assisted" or "energy exchange" pumps are vented through glycol dehydration units and not directly to atmosphere. Such emissions are controlled for affected glycol dehydration units located at area and major sources under 40 C.F.R. Part 63 Subpart HH—NESHAP from Oil and Natural Gas Production Facilities.[230]

Emissions from glycol pumps are already regulated via regulation of glycol dehydration unit process vents by federal NESHAP standards and many state/local standards and regulations.

3. EPA Should Not Impose Tagging and Certification Requirements for Uncontrolled Pumps.

EPA proposes that each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in proposed Section 60.5420a(c)(16)(i).[231] In proposed Section 60.5365a(d)(1), pneumatic pumps operating at 6 scfh or less are not considered affected facilities. Applying this reasoning, uncontrolled pumps that do not exceed the 6 scfh threshold set forth in proposed Section 60.5365a(d)(1) should not be affected facilities and should not be subject to these tracking requirements.

G. Companies Should Not Be Required to Provide Records to EPA Electronically for Review Remotely.

EPA solicits comment regarding how records should be made accessible for review:

> Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office. We solicit comment on whether these records

[229] *Id*.
[230] 40 C.F.R. §§63.764(c) and (d).
[231] Proposed 40 C.F.R. § 60.5393a(b)(3), 80 Fed. Reg. at 56,666.

> also should be sent directly to the permitting agency electronically to facilitate review remotely.[232]

TXOGA opposes sending records directly to the permitting agency electronically to facilitate remote review. There is no basis for companies to be required to "resubmit" information that is already being submitted. Accordingly, we would not support EPA's suggested electronic reporting of records at this time. Subpart OOOOa should determine when E-reports are required. The problem with the EPA's electronic reporting tool is that it is on a site-by-site basis, which is not well suited to Subpart OOOOa regulated sites, since they need to be able to submit reports on an area-wide basis. Many of TXOGA's members are smaller companies that are simply not in a position to bear the costs of this reporting. Moreover, the existing conflicts between state and federal reporting requirements will exacerbate this burden. Only the essential reports should be required to be submitted and then only one time. Finally, state permitting authorities are already overwhelmed with materials and the cost of maintaining this information will be a high burden for state agencies and for EPA. Moreover, EPA has not included the costs of this in its analysis nor has it provided regulatory language. Therefore, issuing a final rule on this issue would require another round of notice and comment to allow for meaningful comment on the method and degree of any submittal requirement.

H. EPA Should Not Require Reporting "Quantitative Environmental Results" Via Corporate Web Sites.

TXOGA opposes EPA's suggestion that companies should be required to report "quantitative environmental results on their corporate web sites. This is a highly burdensome requirement that goes beyond EPA's statutory authority. Specifically, EPA:

> solicits comment on requiring owners and operators of affected facilities to report quantitative environmental results on their corporate maintained web sites. Such results might include monitoring data (including fugitives), quantification of excess emissions and corrective actions, results of performance tests, affected facility status with respect to a standard contained in a rule, and third-party certifications. The EPA requests comment on whether all owner and operators should be required to do this, or only a subset (e.g., based on size of entity, complexity or number of operations, web presence, etc.) and what data we should require them to report; keeping in mind that monitoring and reporting requirements that may be sufficient for government regulators may be insufficient for the public. Government regulators may be satisfied with a regulation that requires a facility to monitor specified parameters (e.g., operating temperature) to generally assure that the facility is operating properly, and to perform a formal compliance test (e.g., measuring actual smokestack emissions) only upon the government's request.[233]

[232] 80 Fed. Reg. at 56,616.
[233] 80 Fed. Reg. at 56,652.

EPA has provided no rationale to support what would plainly be a high burden on companies. Moreover, EPA has provided no statutory support or other citation that would give it authority to impose such a requirement. Requiring companies to include compliance information on their web sites does not fall within the definition of a "standard of performance" within the meaning of Section 111 of the Act. Furthermore, CAA Section 114 gives the Administrator authority to require submittal of information to EPA but does not authorize EPA to require generation of web sites and dissemination of information to the public.[234] If such authority had been contemplated, Congress would have included it in the statute.

In addition, any requirement that environmental performance be reported on corporate web sites raises First Amendment concerns. Any required form of speech through a company's web site would be a content base restriction subject to strict scrutiny.[235] Although TXOGA does not concede that environmental performance reporting via corporate web sites would constitute commercial speech, any regulation of commercial speech will be judged by whether it "directly advances the governmental interest asserted, and whether it is not more extensive than is necessary to serve that interest."[236] This requirement would not survive strict scrutiny or pass the test for commercial speech. This data is already provided to the Agency as required under the regulations and is generally available to the public. Requiring companies to include compliance information on their web sites is unnecessarily duplicative, does not advance the government's interest, and is overly burdensome.[237] TXOGA therefore urges EPA not to move forward with this requirement.

CONCLUSION

TXOGA respectfully requests the Agency to adopt the changes recommended above. Please contact Cory Pomeroy at cpomeroy@txoga.org or Shannon Broome at shannon.broome@kattenlaw.com with any questions regarding these comment.

[234] *See* 42 U.S.C. § 7414.
[235] *See Reed v. Town of Gilbert*, 135 S. Ct. 2218 (2015) (content-based regulations of speech are subject to strict scrutiny).
[236] *Cent. Hudson Gas & Elec. Corp. v. Pub. Serv. Comm'n* , 447 U.S. 557, 566 (1980).
[237] Costs for building and maintaining such a web site could easily each $15,000 or more annually per company, depending on the number of reports and site configuration.